National Parks Conservation Association Et Al

Exhibits

OIL AND GAS SECTOR

REASONABLE PROGRESS

FOUR-FACTOR ANALYSIS OF CONTROLS

FOR FIVE SOURCE CATEGORIES:

NATURAL GAS-FIRED ENGINES

NATURAL GAS-FIRED TURBINES

DIESEL-FIRED ENGINES

NATURAL GAS-FIRED HEATERS AND BOILERS

FLARING AND INCINERATION

Prepared for National Parks Conservation Association

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EXECUTIVE SUMMARY

States are required to revise and submit revisions to their regional haze state implementation plans to make reasonable progress toward the national visibility goal, with the next revision due to the U.S. Environmental Protection Agency by July 31, 2021. In this second round of regional haze plans, each state needs to look broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of emission reducing measures. Oil and gas development is a significant source of visibility-impairing emissions in many states, including emissions of nitrogen oxides (NOx), volatile organic compounds (VOCs), sulfur dioxide (SO_2), and particulate matter (PM).

This report conducts a four-factor analysis of reasonable progress controls for five air emission source categories within the oil and gas development industry: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired heaters and boilers, and flaring. This report includes a compilation of information on available pollution control options for visibility-impairing pollutants, provides cost of controls (where available) and documents the cost effectiveness of controls for various size units and a range of operating levels. The report also provides information for specific pollution controls regarding the three other reasonable progress factors: the time necessary for compliance to install the controls, the energy and non-air quality environmental impacts of the controls, and the remaining useful life of both the source category and the pollution control in question, if it differs from that of the source category.

With respect to the cost of controls, the authors used control cost data that were relied upon by federal, state, and local air agencies. Also, capital costs of control were amortized based on the expected useful life of the unit unless a shorter useful life of the specific pollution control was expected, all of which is documented in the report. The authors did not escalate costs to current dollars, because in many cases, the cost information was more than five years old, and EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis. Last, the authors compiled information on federal, state, and local air emission limitations that were required to be met by existing sources and thus required a retrofit of pollution controls to the source category. This assessment includes an evaluation of the lowest emission limits required of existing sources by state and local agencies and correlates those emission limits to specific pollution controls. Looking to state regional haze plans, the authors note that determinations of cost effectiveness for a particular source category should be based on the costs that similar sources have had to incur to meet Clean Air Act requirements.

Although the authors attempted to identify the pollution control methods that were both cost effective and the most effective at reducing visibility-impairing emissions and evaluated varying levels of operation, it is recognized that air pollution control determinations to retrofit existing sources cannot always be implemented via a "one-size-fits-all" approach. Thus, in some cases, a few different options for retrofit pollution controls are recommended for a source category, with the primary reasons for differentiating recommended pollution controls being based on size of the unit and/or operating capacity factor. Below the authors summarize the pollution controls that are presumed to be the best control options for each source category, with a focus on NOx pollution controls.

Summary of Cost Effective Control Options for Air Emissions Sources of the Oil and Gas Sector

SOURCE CATEGORY	NOx POLLUTION CONTROL	NOx COST EFFECTIVENESS ($/TON)	PERCENT NOx REMOVAL, AND EMISSION RATES	OTHER POLLUTION CONTROLS
Natural Gas (NG)-Fired RICE Compressors	Replace with Electric Compressors	$1,228–$2,766/ton (2011 $)	100% Removal of NOx and All Other Pollutants	Power Compressors with Renewable Energy
NG-Fired RICE Rich Burn >50 hp	Nonselective Catalytic Reduction (NSCR) and Air Fuel Ratio Controller (AFRC)	$44–$3,383/ton (2009$)	94–98% 11–67 ppmv 0.16–1.0 g/hp-hr	VOC Controls integrated into NSCR.
NG-Fired RICE Lean Burn >50 hp	Low Emission Combustion (LEC)	$47–$941/ton (2001$)	87–93% 75–150 ppmv 1.0–2.0 g/hp-hr	Oxidation Catalyst for VOC Emissions
	Selective Catalytic Combustion (SCR)	$628–$13,567/ton (1999$–2001$)	90–99% 11–73 ppmv 0.15–1.0 g/hp-hr	
NG-Fired Combustion Turbines	SCR (alone or with Dry Low NOx Combustion)	$566–$13,238/ton (1999–2000$)	80–95+% 3-15 ppmv	Oxidation Catalyst for VOC Emissions
	Dry Low NOx Combustion	$208–$2,140/ton (1999$–2000$)	80–95% 9-25 ppmv	
Diesel-Fired RICE	Use Electric Engines and Tier 4 Gen Sets -------------------- OR Replace Older Engines w/ Tier 4	$564–$9,921/ton (2010$)	94% 0.5 g/hp-hr --------------------- 49%–96% 0.3-3.5 g/hp-hr	Catalytic Diesel Particulate Filter For PM (81%-97.5% control) Use of Ultra-Low Sulfur Diesel Fuel
	Replace w/ NG RICE	Implemented by several companies	85–94%	
	Retrofit with SCR	$3,759–$6,781/ton	90%	
Heaters/Boilers >20 MMBtu/hr	Ultra-Low NOx Burners (ULNB)	$545–$3,270/ton (2018$)	93% 6 ppmv	Other Options: Lower heater-treater temperatures Install insulation on separators
	SCR	$1,025–$6,149/ton (2018$)	97% 2.5 ppmv	
Heaters/Boilers >5 and ≤20 MMBtu/hr	ULNB	$727–$5,232/ton (2018$)	93% 6 ppmv	
Heaters/Boilers ≤5 MMBtu/hr	Replacement of Heater with New Unit with ULNB	$4,055-$10,809/ton (2005$)	82–89% 9-20 ppmv	

Note: The range of cost effectiveness for each control reflects a range of capacities of emission units and also reflects a wide range of operating hours per year. Refer to the report for more details.

As shown in the table above, there are technically feasible and cost effective options to control NOx, VOCs, PM, and SO2 from these four source categories of combustion-related emissions from the oil and gas sector and, in most cases, there are many examples of state and local air agency rules that require these or similar levels of control for existing sources. While many of these state and local rules were adopted to address the National Ambient Air Quality Standards (NAAQS), cost effectiveness of controls is generally part of the rulemaking process under reasonably available control technology (RACT) and best available retrofit control technology (BARCT – which applies in California) determinations. Given that state and local air agencies have found the costs of these controls to be reasonable for imposition of various pollution control requirements, these costs should be considered reasonable to impose to meet other Clean Air Act requirements including under the Regional Haze Program.

For flaring of waste gases, the following control options are recommended:

- Prevent flaring of excess gases through capture and use requirements instead of flaring
- Prevent flaring at gas sweetening and other processing plants by proper maintenance, training, installing duplicative equipment to minimize upsets
- Require documentation of flaring episodes with all relevant info to estimate emissions and to assess causes and actions to mitigate
- Thermal incineration should be considered in lieu of flaring due to ability for improved VOC destruction and available NOx and SO2 controls (if sour/acid gas is being combusted)

The ultimate goal to reduce VOC, NOx, PM, and SO2 emissions from excessive flaring should be to eliminate or minimize flaring to the maximum extent possible and to use, and not waste, excess gas produced.

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LIST OF TERMS

2SLB	Two-stroke lean-burn
4SLB	Four-stroke lean-burn
4SRB	Four-stroke rich-burn
A/F	Air-to-fuel ratio
ACT	Alternative control techniques
AFRC	Air/fuel ratio controller
APCD	Air pollution control district
AQMD	Air Quality Management District
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
BART	Best Available Retrofit Technology
BAT	Best Available Technology
BSFC	Brake-specific fuel consumption
BLM	U.S. Bureau of Land Management
CARB	California Air Resources Board
CEPCI	Chemical Engineering Plant Cost Index
CAA	Clean Air Act
CDPF	Catalyzed diesel particulate filter
CDPHE	Colorado Department of Public Health and Environment
CI	Compression ignition
CEMS	Continuous emissions monitoring system
CO	Carbon monoxide
CO_2	Carbon dioxide
CSAPR	Cross-State Air Pollution Rule
DRE	Destruction and removal efficiency
DPF	Diesel particulate filter
DOE	U.S. Department of Energy
DLNC	Dry low NOx combustors
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FGR	Flue gas recirculation
4CAQTF	Four Corners Air Quality Task Force
GPU	Gas production unit
Gen Set	Generator-Set Engine
g/bhp-hr	Grams per brake horsepower-hour
g/hp-hr	Grams per horsepower-hour
HAP	Hazardous air pollutant

LIST OF TERMS

HC	hydrocarbon
H_2S	Hydrogen sulfide
hp	horsepower
kW	Kilowatt
INGAA	Interstate Natural Gas Association of America
IR	Ignition timing retard
LB	Lean-burn
LEC	Low emission combustion
LNB	Low NOx burners
MCF	Thousand cubic feet
MW	Megawatt
MMBtu	Million British Thermal Unit (heat input)
MMscf	Million standard cubic feet
NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPS	National Park Service
NSPS	New Source Performance Standards
NOx	Nitrogen oxides
NMHC	Non-methane hydrocarbons
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standards
OTC	Ozone Transport Commission
PEMS	Parametric emissions monitoring system
PM	Particulate matter
$PM_{2.5}$	Particulate matter with an aerodynamic diameter equal to or less than 2.5 microns
ppm	Parts per million
ppmv	Parts per million by volume
ppmvd	Parts per million dry volume
PSC	Prestratified charge
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
RACT	Reasonably Available Control Technology
RECLAIM	Regional Clean Air Incentives Market
RHR	Regional Haze Rule
RB	Rich-burn
RICE	Reciprocating internal combustion engine(s)

LIST OF TERMS

SMAQMD	Sacramento Metropolitan Air Quality Management District
SCAQMD	South Coast Air Quality Management District
SCR	Selective catalytic reduction
SI	Spark ignition
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SOx	Sulfur oxides
TCEQ	Texas Commission on Environmental Quality
TSD	Technical support document
THC	Total hydrocarbons
ULSD	Ultra-low sulfur diesel
ULNB	Ultra-low NOx burners
VCAPCD	Ventura County Air Pollution Control District
VOC	Volatile organic compound

I. BASIS FOR REASONABLE PROGRESS CONTROLS

Under the Regional Haze Rule (RHR), states are required to revise and submit periodic comprehensive revisions to their regional haze plans, with the next revision due to be submitted to the U.S. Environmental Protection Agency (EPA) by July 31, 2021.[1] This next round of regional haze plans is referred to as the regional haze plan for the second implementation period. States' regional haze plans address regional haze in all Class I areas within the state and in all Class I areas located outside the state that may be affected by emissions from within the state.[2] Each state's plan and plan revision must include, among other things, a long term strategy which is to be determined as follows:

> Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to [40 C.F.R. § 51.308] (f)(2)(i) through (iv). In establishing its long-term strategy for regional haze, the State must meet the following requirements:
>
> (i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.
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> . . .

40 C.F.R. § 51.308(f)(2)(i).

The requirement for evaluation of emission reduction measures quoted above is generally referred to as a "four-factor analysis" or a "reasonable progress analyses" of controls. To reiterate, the four factors that must be considered when evaluating reasonable progress controls for a source are (1) cost of compliance, (2) time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of the source. In the first round of regional haze plans, States were required to evaluate and impose emission limitations that reflect "best available

[1] 40 C.F.R. § 51.308(f).

[2] *Id.*

retrofit technology" (BART) at all BART-subject sources (which were clearly defined by regulation). States also were required to identify sources to control in order to make reasonable progress towards the national visibility goal; for these sources states tended to focus on the larger single sources of emissions, as was also the focus of BART controls. In the second round of regional haze plans, each state needs to look more broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of controls. Each state must adopt emission-reduction measures in its regional haze plan developed for the second implementation period to make reasonable progress towards the national visibility goal. The Clean Air Act (CAA) mandated that regional haze plans must address sources of "emissions from which may reasonably be anticipated to cause or contribute to ***any*** impairment of visibility" (emphasis added)).[3]

Air emissions from oil and gas development, production, treatment, and transmission represent a significant quantity of regional haze-impairing emissions in many states. Air emissions from oil and gas development that can impact visibility include nitrogen oxides (NOx), sulfur dioxide (SO_2), directly emitted particulate matter (PM), volatile organic compounds (VOCs), and ammonia. NOx, SO_2, VOCs, and ammonia, initially emitted as gases, often convert into fine (i.e., less than 2.5 micrometers in diameter) particulate matter ($PM_{2.5}$) in the atmosphere, which can travel far and which are very efficient in scattering light and impacting visibility. Oil and gas development often occurs on federal, state, and/or private lands near or even adjacent to Class I areas. Oil and/or gas development tends to be clustered in certain areas where such fossil fuels are found. Many of the air emissions sources associated with gas and/or oil production are minor sources, not large enough in emissions to trigger new source review permitting. However, such sources collectively are often significant contributors to visibility impairment in Class I areas due to sheer numbers of emission sources or proximity to Class I areas, or both.

In the United States, oil and gas production has been increasing and is projected to continue to increase in the future. States with significant increases in oil production since 2013 include Colorado with almost a tripling of production since 2013, New Mexico with more than a doubling of production since 2013, Texas with a 73% increase in production since 2013, and North Dakota with a 48% increase since 2013.[4] States with significant increases in gas production include, among others, Ohio with annual gas production in 2018 that is more than 14 times higher than it was in 2013, West Virginia with a 143% increase in gas production since 2013, North Dakota with a doubling of production in 2018 compared to 2013, Pennsylvania with a 91% increase in gas production since 2013, and New Mexico with a 27% increase in gas production since 2013.[5] The U.S. Energy Information Administration (EIA) currently projects crude oil production in the United States to be 25% higher in 2021 than it was in 2018[6] and marketed gas production in the United States to be 13% higher in 2021 than it was in 2018.[7] In many areas of the country, these increases in production are projected to continue well into the future. For

[3] 42 U.S.C. § 7491(b)(2).
[4] EIA, Crude Oil Production, Annual-Thousand Barrels, 2013 to 2018, *available at:* https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.
[5] EIA, Natural Gas Gross Withdrawals and Production, Marketed Production, Annual Million Cubic Feet, 2013 to 2018, *available at:* https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.
[6] EIA Short-Term Energy Outlook, U.S. Liquid Fuels, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/us_oil.php.
[7] EIA, Short-Term Energy Outlook, Natural Gas, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/natgas.php.

example, the New Mexico Oil and Gas Association recently presented a report to state lawmakers indicating that there will be "solid growth for the next decade or so" in the Permian Basin.[8]

There are several combustion-related sources of visibility-impairing emissions associated with oil and gas development. Various engines, typically fired by natural gas or diesel, are used in the drilling and completion phase, in the processing of natural gas, and at compressor stations. On-site power sources are often used, in the form of natural gas-fired engines, diesel generators, and/or combustion turbines. Natural gas-fired boilers and heaters are also used throughout the oil and gas production and process segments of the industry, to generate power, and to create steam and process heat. Those engines and combustion turbines emit significant quantities of NOx and VOCs and also of SO_2 and PM for diesel-fired engines. Flaring of excess and waste gas can be a significant source of SO_2 and NOx emissions.

This report presents a four-factor analysis of reasonable progress controls for NOx and VOCs, and SO_2 and PM as appropriate, for five significant air emissions source categories associated with oil and gas development: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired boilers and heaters, and flaring/incineration of waste or excess gas. This report (1) proposes pollution controls and/or measures for such sources considering the control technology available and the most effective controls; (2) compiles cost data with a focus on data relied upon by federal, state, and local air agencies in regulatory decisions; (3) evaluates non-air quality environmental and energy impacts of controls; and (4) considers the remaining useful life of the equipment.

It is important to note that, while New Source Performance Standards (NSPS) exist for these source categories, the existence of an NSPS does not negate the need for a four-factor analysis of controls to achieve reasonable progress towards the national visibility goal for several reasons. First, it has been many years since the NSPS standards for RICE units, gas turbines, and small boilers have been re-evaluated. Although EPA correctly states in its 2019 Regional Haze guidance that "[t]he [CAA] requires EPA to review, and if necessary, revise NSPS every 8 years,"[9] EPA has not always updated the NSPS emission standards for a source category in accordance with this timetable. Second, the NSPS emission standards only apply to a facility if it is constructed, modified, or reconstructed after the applicability date.[10] The applicability date of an NSPS (or of a revised NSPS emission standard) is set as either the date of publication of any proposed or of any final rulemaking establishing the standard. Third, when EPA adopts or revises NSPS for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally applicable emission standards and not a source-specific evaluation of controls.

Further, while EPA's Regional Haze guidance states that, if a new or modified unit is subject to and complying with an NSPS promulgated or reviewed since July 31, 2013, it is unlikely that new or existing controls are available or more effective, no such assumption should be made without considering the

[8] As discussed in Report: New Mexico oil, gas boom to continue, by Susan Montoya Bryan/Associated Press, September 3, 2019, Albuquerque Journal, *available at:* https://www.abqjournal.com/1361629/report-new-mexico-oil-gas-boom-to-continue.html.

[9] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 23, note 44.

[10] *See* 40 C.F.R. § 60.1(a); *see also* definitions in § 60.2 and regulations on "modification" and "reconstruction" in §§ 60.14 and 60.15.

specific emission and operational characteristics of the source in question. EPA's statements are problematic and need clarification. One cannot simply determine the last time the NSPS for a source category was amended and assume that if the amendments occurred within the last eight years, the NSPS is up to date. Section 111(b)(1)(B) of the CAA requires EPA to review and revise each NSPS at least every eight years, to essentially determine if the NSPS currently reflect the "degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[11] EPA amends its NSPS for various reasons (e.g., changes in test methods or protocols, clarifications), but thorough reviews and revisions generally occur much less frequently — in many cases less frequently than every eight years as required by the CAA. Table 1 below shows the NSPS applicable to RICE units, turbines, and small boilers and provides the most recent date of EPA's comprehensive review and revision. The NSPS rules applicable to RICE units and gas turbines were last subject to a comprehensive revision to reflect the best-demonstrated technology well before July 31, 2013.

Table 1. NSPS Categories that Address RICE, Natural Gas Turbines, and Small Boilers

NSPS Subpart in 40 C.F.R. Part 60	Emission Source(s)	Date of Promulgation of Most Recent Revisions
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	2/27/06 (reflects most recent review of the emission standards)
GG	Stationary Gas Turbines	9/20/79 (first promulgation of NSPS for gas turbines and revised standards promulgated at Subpart KKKK)
IIII	Stationary Compression Ignition Internal Combustion Engines	6/28/11 (reflects most recent adoption of emission standards for this source category)
JJJJ	Stationary Spark Ignition Internal Combustion Engines	1/18/08 (NSPS for source category first promulgated, and reflects most recent review of emission standards)
KKKK	Stationary Combustion Turbines constructed, reconstructed or modified after 2/18/05	7/6/2006 (first promulgation of NSPS Subpart KKKK, and reflects most recent review of emission standards)
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction. Modification, or Reconstruction Commenced after 8/23/11 and on or before 9/15/15	6/3/2016 (reflects most recent review the emission standards)
OOOOa	Crude Oil and Natural Gas Production, Transmission, and Distribution from which Construction. Modification, or Reconstruction Commenced after 9/18/15	6/3/2016 (NSPS Subpart first promulgated)

[11] *See* Section 111(a)(1) of the Clean Air Act, 42 U.S.C. § 7411(a)(1).

Thus, while the NSPS may be a place to start in evaluating pollution controls for air emissions sources associated with the oil and gas industry, it is also necessary to evaluate if more stringent requirements and pollution controls have been required in state rules or local air rules, air permits, or other requirements. Review of state regulations and state implementation plans, particularly to address national ambient air quality standards (NAAQS) which requires reductions in emissions from existing sources, is necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided below reflects a comprehensive review of the pollution controls and techniques and associated emissions levels applicable to each of the source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the reasonable useful life of the emission source being evaluated.

II. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES

Reciprocating internal combustion engines (RICE) are used in a variety of applications, including gas compression, pumping, and power generation. RICE can either be: (1) spark-ignited and fueled by natural gas, propane, or gasoline; or (2) compression-ignited and fueled by diesel. Spark-ignition engines fueled by natural gas, propane, and gasoline can operate lean (i.e., with a higher air-to-fuel ratio) or rich (i.e., with a lower air-to-fuel ratio). Compression-ignition diesel-fueled engines operate lean. A rich-burn engine operates with excess fuel during combustion, whereas a lean-burn engine operates with excess air.

Natural gas-fired RICE are the focus of this section and are used throughout the oil and gas industry, as described by EPA:

> Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles). The size of these engines ranges from 50 brake horsepower (bhp) to 11,000 bhp. In addition, some engines in service are 50–60 years old and consequently have significant differences in design compared to newer engines, resulting in differences in emissions and the ability to be retrofitted with new parts or controls.
>
> At pipeline compressor stations, reciprocating engines are used to power reciprocating compressors that move compressed natural gas (500–2000 [pounds per square inch gauge (psig)]) in a pipeline. These stations are spaced approximately 50 to 100 miles apart along a pipeline that stretches from a gas supply area to the market area. The reciprocating compressors raise the discharge pressure of the gas in the pipeline to overcome the effect of frictional losses in the pipeline upstream of the station, in order to maintain the required

suction pressure at the next station downstream or at various downstream delivery points. The volume of gas flowing and the amount of subsequent frictional losses in a pipeline are heavily dependent on the market conditions that vary with weather and industrial activity, causing wide pressure variations. The number of engines operating at a station, the speed of an individual engine, and the amount of individual engine horsepower (load) needed to compress the natural gas is dependent on the pressure of the compressed gas received by the station, the desired discharge pressure of the gas, and the amount of gas flowing in the pipeline. Reciprocating compressors have a wider operating bandwidth than centrifugal compressors, providing increased flexibility in varying flow conditions. Centrifugal compressors powered by natural gas turbines are also used in some stations and are discussed in another section of this document.[12]

Natural gas-fired reciprocating engines are also used at well sites across the oil and gas industry in various applications including, e.g., reciprocating compressors and pump engines used to lift oil out of a well.

Natural gas-fired RICE can be classified as two-stroke or four-stroke engines. In a two-stroke engine, the power cycle occurs in a single crankshaft revolution and two strokes: an intake/compression stroke; and a power/exhaust stroke. In a four-stroke engine, the power cycle is completed with two crankshaft revolutions and four strokes: an intake stroke; compression stroke; power stroke; and exhaust stroke. Natural gas-fired RICE units encompass three engine types or classes:

1. Two-stroke lean-burn (2SLB)
2. Four-stroke lean-burn (4SLB)
3. Four-stroke rich-burn (4SRB)

NOx emissions from RICE are highly dependent on combustion temperature, with higher temperatures resulting in more NOx emissions. Rich-burn engines operate with an air-to-fuel ratio (A/F) that is rich with fuel resulting in higher fuel use, increased combustion temperatures, increased engine power, and decreased engine efficiency relative to a lean-burn engine. Lean-burn engines operate with an A/F that is lean with fuel resulting in less fuel use, decreased combustion temperatures, decreased engine power, and increased engine efficiency relative to a rich burn engine.

UNITS

NOx emissions from RICE are generally expressed as emission rates in grams per brake horsepower hour (g/bhp-hr) or as a concentration in parts per million by volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 15% oxygen. Emission rates expressed in g/bhp-hr and grams per horsepower-hour (g/hp-hr) are assumed to be roughly equivalent for the RICE applications in this section. The following conversion factors from EPA's Updated Information on NOx Emissions and Control Techniques document[*] are used in this section:

[12] EPA, AP-42, Fifth Edition, Volume 1, Chapter 3: Stationary Internal Combustion Sources.

Uncontrolled rich-burn Spark-Ignition (SI) engines and rich-burn engines controlled with nonselective catalytic reduction (NSCR)……………………….67 ppmv = 1 g/bhp-hr Uncontrolled lean-burn engines, lean-burn engines controlled with selective catalytic reduction (SCR), and rich-burn engines controlled with prestratified charge™ (PSC) technology……………………….73 ppmv = 1 g/bhp-hr Lean-burn engines controlled with Low Emission Combustion (LEC) Technology……………………………………………………………………………..75 ppmv = 1 g/bhp-hr * EPA, Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques, September 2000 (EPA-457/R-00-001)

A. RICH-BURN RICE: COMBUSTION CONTROLS

Emission control technologies for RICE depend on the A/F and therefore different controls apply to different engine types. NOx emissions reductions from these engines can be achieved through combustion controls or through post-combustion (add-on) controls. The following retrofit combustion control technologies for rich-burn RICE are described by EPA in its *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines*, and EPA's descriptions are reprinted below:[13]

Rich-Burn A/F Adjustments

> Adjusting the A/F toward fuel-rich operation reduces the oxygen available to combine with nitrogen, thereby inhibiting NOx formation. The low-oxygen environment also contributes to incomplete combustion, which results in lower combustion temperatures and, therefore, lower NOx formation rates. The incomplete combustion also increases [carbon monoxide (CO)] emissions and, to a lesser extent, [hydrocarbons (HC)] emissions. Combustion efficiency is also reduced, which increases brake-specific fuel consumption (BSFC). Excessively rich A/F's may result in combustion instability and unacceptable increases in CO emissions.
>
> The A/F can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished with an automatic A/F control system.
>
> The achievable NOx emission reduction ranges from approximately 10 to 40 percent from uncontrolled levels. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 14.0 g/hp-hr (640

[13] EPA-453/R-93-032 *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines* (July 1993), *available at*: https://www3.epa.gov/airquality/ctg_act/199307_nox_epa453_r-93-032_internal_combustion_engines.pdf [hereinafter referred to as "EPA 1993 Alternative Control Techniques Document for RICE"].

> to 940 ppmv). Available data show that the achievable NOx reduction using A/F varies for each engine model and even among engines of the same model, which suggests that engine design and manufacturing tolerances influence the effect of A/F on NOx emission reductions.[14]

NOx Removal Efficiency:	*10-40%*
Controlled NOx Emission Rates:	*9.5 to 14.0 g/hp-hr*
	640 to 940 ppmv

Rich-Burn Ignition Timing Retard (IR)

> Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offer the potential for reduced NOx formation. . . .
>
> Ignition timing can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished using an electronic ignition control system.
>
> The achievable NOx emission reduction ranges from virtually no reduction to as high as 40 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 15.8 g/hp-hr (640 to 1,060 ppmv). Available data and information provided by engine manufacturers show that, like AF, the achievable NOx reductions using IR are engine-specific.[15]

NOx Removal Efficiency:	*0-40%*
Controlled NOx Emission Rates:	*9.5 to 15.8 g/hp-hr*
	640 to 1,060 ppmv

A/F adjustment and IR can be employed together to reduce NOx emissions from rich-burn RICE. According to EPA, the achievable emissions reductions are similar to that for A/F adjustments (i.e., 10-40%) but may offer the potential to minimize some of the adverse impacts of other operating parameters (e.g., CO emissions, engine response, fuel consumption).[16]

Limited cost data indicate that combustion controls for rich-burn RICE costs between $400 to $1,000 per ton of NOx reduced for engines greater than 500 horsepower (hp).[17]

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[14] *Id.* at 2-5.
[15] *Id.* at 2-5 and 2-9.
[16] *Id.* at 2-9.
[17] *Id.* at 2-30. *See also* California Air Resources Board (CARB) Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines, November 2001, Table V-2 at V-3, *available at*: https://ww3.arb.ca.gov/ractbarc/rb-iceall.pdf [hereinafter referred to as "CARB 2001 Guidance"]. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.

B. RICH-BURN RICE: PRESTRATIFIED CHARGE (PSC)

Prestratified charge (PSC) is a combustion modification that converts rich-burn engines to lean-burn engines by retrofitting the air injectors to make a leaner A/F ratio. PSC is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

> This add-on control technique facilitates combustion of a leaner A/F. The increased air content acts as a heat sink, reducing combustion temperatures, thereby reducing NOx formation rates. Because this control technique is installed upstream of the combustion process, PSC® is often used with engines fueled by sulfur-bearing gases or other gases (e.g. sewage or landfill gases) that may adversely affect some catalyst materials.
>
> Prestratified charge applies only to four-cycle, carbureted engines. Pre-engineered, "off-the-shelf" kits are available for most new or existing candidate engines, regardless of age or size. According to the vendor, PSC® to date has been installed on engines ranging in size up to approximately 2,000 hp.
>
> The vendor offers guaranteed controlled NOx emission levels of 2 g/hp-hr (140 ppmv), and available test data show numerous controlled levels of 1 to 2 g/hp-hr (70 to 140 ppmv). The extent to which NOx emissions can be reduced is determined by the extent to which the air content of the stratified charge can be increased without excessively compromising other operating parameters such as power output and CO and HC emissions. The leaner A/F effectively displaces a portion of the fuel with air, which may reduce power output from the engine. For naturally aspirated engines, the power reduction can be as high as 20 percent, according to the vendor. This power reduction can be at least partially offset by modifying an existing turbocharger or installing a turbocharger on naturally aspirated engines. In general, CO and HC emission levels increase with PSC®, but the degree of the increase is engine-specific. The effect on BSFC is a decrease for moderate controlled NOx emission levels (4 to 7 g/hp-hr, or 290 to 500 ppmv), but an increase for controlled NOx emission levels of 2 g/hp-hr (140 ppmv) or less.[18]

PSC NOx Removal Efficiency:	*87% (85-90%, EPA 2000)*[19]
Controlled NOx Emission Rates:	*2 g/hp-hr*
	140 ppmv

PSC NOx reduction efficiency depends on how much the air content can be increased without adversely affecting the performance of the engine; achieving lower NOx rates with PSC will result in sacrifices in engine power output. PSC, generally, can only achieve a NOx emission rate as low as 2 g/bhp-hr. EPA re-affirmed the limitations of PSC in its 2000 Updated Information on NOx Emissions and Control Techniques for RICE, stating:

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[18] EPA 1993 Alternative Control Techniques Document for RICE at 2-9 to 2-10.

[19] EPA-457/R-00-001 *Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques,* September 2000, *available at*: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF [hereinafter referred to as "EPA 2000 Updated Information on NOx Emissions and Control Techniques"].

> The 1993 ACT document found that the achievable NOX emission level for PSC is 2.0 g/bhp-hr, based on the vendor's guarantees. This value is generally consistent with the information gathered for this project and is a representative value for the NOX emission level that can be achieved using PSC control technology.[20]

Limited cost data indicate that PSC achieving 80% NOx reduction efficiency costs between $200 to $800 per ton of NOx reduced for engines ranging in size from 50–1,500 hp.[21]

Even the best-case NOx emissions reductions for PSC are generally lower than the emissions reductions that can be accomplished with the nonselective catalytic reduction (NSCR) technologies discussed below. And NSCR also generally costs less, with capital and annual costs less than PSC for almost all engine sizes, according to data from EPA.[22] However, for fuels with higher sulfur content (e.g., waste gases), PSC technology can be effective at achieving NOx emissions reductions where higher sulfur fuels would adversely impact catalyst material used in post-combustion control technologies such as NSCR.

C. RICH-BURN RICE: NONSELECTIVE CATALYTIC REDUCTION (NSCR)

The use of NSCR technology began in the 1970s with the application of 3-way catalysts to gasoline-fueled motor vehicles in order to simultaneously control carbon monoxide, VOCs, and NOx emissions. In automobiles, the technology is known as a "catalytic convertor." Since then, NSCR has been widely applied to stationary engines. NSCR is usually also accompanied by an air/fuel ratio controller (AFRC), which is used to adjust the combustion parameters across the operating range of the engine in order to maintain the conditions needed for the efficient operation of the NSCR system (e.g., sufficient excess oxygen in the exhaust gas).

NSCR is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

> Nonselective catalytic reduction is essentially the same catalytic reduction technique used in automobile applications and is also referred to as a three-way catalyst system because the catalyst reactor simultaneously reduces NO_X, CO, and HC to water (H_2O), carbon dioxide (CO_2), and diatomic nitrogen (N_2). The chemical stoichiometry requires that O_2 concentration levels be kept at or below approximately 0.5 percent, and most NSCR system require that the engine be operated at fuel-rich A/F's. . . .
>
> Nonselective catalytic reduction applies only to carbureted rich-burn engines and can be retrofit to existing installations. Sustained NOx reductions are achieved with changes in ambient conditions and operating loads only with an automatic A/F control system. . . .

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[20] *Id.* at 4-21.

[21] *See* CARB 2001 Guidance at Table V-2 at V-3. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.

[22] *See* EPA's 1993 Alternative Control Techniques Document for RICE Table 2-12 at 2-30.

> Catalyst vendors quote NOx emission reduction efficiencies of 90 to 98 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr (20 to 110 ppmv). . . .
>
> The predominant catalyst material used in NSCR applications is a platinum-based metal catalyst. The spent catalyst material is not considered hazardous, and most catalyst vendors accept return of the material, often with a salvage value that can be credited toward purchase of replacement catalyst.[23]

NSCR NOx Removal Efficiency:	*90-98%*
Controlled NOx Emission Rates:	*0.3 to 1.6 g/hp-hr*
	20 to 110 ppmv

According to EPA, when California air district standards were tightened to 96% NOx reduction and emission limits of 25 ppmv (0.37 g/bhp-hr), facilities shifted from PSC to NSCR to meet the standard.[24] This level of NOx control can be met with an NSCR retrofit to an existing unit. For example, retrofit installations of NSCR on five Caterpillar rich burn engines in Texas achieved a NOx reduction of 96% or greater on all of the engines.[25] On two of those engines, testing conducted after more than 4,000 hours of operation with NSCR indicated the NSCR controls were still achieving a 95% NOx reduction.[26] Employing NSCR to reduce NOx emissions from EPA's uncontrolled emission rate of 15.8 g/bhp-hr to 1.0 g/bhp-hr corresponds to a NOx emission reduction efficiency of 94%. Unless otherwise noted, the analyses provided further below in this section assume a 94% NOx reduction efficiency to meet a 1 g/bhp-hr emission rate. Lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency (see Section II.G., below).

NSCR can effectively reduce CO, HC, VOCs (include formaldehyde), as well as NOx emissions, if properly optimized for control of all these pollutants. Such systems must control the A/F carefully to provide enough oxygen to ensure that CO and VOCs are oxidized but also limit oxygen enough to ensure the NOx is effectively reduced. The oxygen content of the exhaust gas needs to be within a narrow window to ensure effective control of all three pollutants, and thus an AFRC is necessary along with an oxygen sensor to provide feedback to the AFRC to ensure the proper fuel-rich operation.

HOURS OF OPERATION FOR RICE

Stationary RICE are used in a variety of applications throughout the oil and gas sector, from providing on-site power, driving pumps or compressors, and drilling operations at well sites to driving pipeline compressor stations to powering pumps, compressors, and refrigeration at gas processing plants. Because of the varying uses for RICE units, RICE units used in the oil and gas sector cover the full

[23] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[24] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-19.
[25] OTC Technical *Information Oil and Gas Sector Significant Stationary Sources of NOx Emissions* October 17, 2012, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf at 45.
[26] *Id.*

range of operating schedules. In providing cost estimates herein, this report presents cost effectiveness analyses to reflect operating as few as 2,000 hours per year and as high as 8,000 hours per year. For example, compressor stations typically operate continuously, although not all compressor engines at a compressor station operate continuously. On the other hand, RICE units used for backup onsite electrical generation may not operate much at all in a year. Thus, a low-end operating capacity factor and a high-end capacity factor were assumed to reflect a range of costs across varying levels of operation.

A cost effectiveness analysis of NSCR was performed in 2010 for EPA, to help determine national impacts associated with EPA's final rule for Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP).[27] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for retrofitting NSCR on existing 4SLB engines from industry groups, vendors, and manufacturers of RICE control technology. E^C/R Incorporated performed a linear regression analysis[28] on the data set to determine the following linear equation for annual cost, which includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

NSCR Annual Cost = $4.77 x (hp) + $5,697 (2009$)

The capital cost equation for retrofitting an AFRC and NSCR on a 4SRB engine was determined by E^C/R Incorporated to be, as follows:

NSCR Capital Cost = $24.9 x (hp) + $13,118 (2009$)

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E^C/R document does not explain why it assumed a 10-year life of controls for estimating the annualized capital costs. The life of a RICE unit is generally much longer than ten years, and is often at least thirty years.[29] The assumed 10-year life was not based on the catalyst replacement timeframe, because the E^C/R operating costs took into account the cost for replacing the catalyst every three years, as well as replacing the thermocouple every 7.5 years, the crankcase filters every three months, the oxygen sensor on a quarterly basis, and rotating the catalyst for cleaning annually.[30] Thus, the assumed 10-year life of an NSCR system seems arbitrary. In cost analyses done in 2000 for EPA, an equipment life of NSCR of fifteen years was assumed.[31] The state of Colorado also recently assumed a 15-year life of

[27] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf.

[28] *Id.* The report notes that the linear equation has a correlation coefficient (R) of 0.7987, concluding that it "shows an acceptable representation of cost data."

[29] *See, e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950's to 1970's still operating at such facilities.

[30] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.

[31] *See* August 11, 2000, E.H. Pechan & Associates, Inc., NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States, at 5 and at A-2, *available at*: https://www3.epa.gov/ttn/ecas/regdata/cost/pechan8-11.pdf. *See also* EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

NSCR for RICE units.[32] Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,[33] it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented herein, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report, to be consistent with EPA's Control Cost Manual which recommends the use of the bank prime interest rate.[34] The bank prime rate fluctuates over time, and the highest it has been in the past five years is 5.5%.[35] In its cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA also used an interest rate of 5.5%.[36] Thus, a 5.5% interest rate has been used for the revised cost calculations presented herein.

Table 2 shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA's 2010 RICE NESHAP, adjusted to reflect a 5.5% interest rate and 15-year life of controls.

Note that lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency than the 94% assumed in the table below (see Section II.G.) and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

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[32] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category, circa 2008 [hereinafter referred to as "CDPHE RP for RICE"], at 8, *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf.

[33] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

[34] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[35] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.

[36] *Available at:* https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Table 2. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary Spark-Ignition (SI) Engines[37]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,251/ton	$813/ton
	200	$5,859	$898/ton	$224/ton
	500	$6,971	$427/ton	$107/ton
	1,000	$8,824	$270/ton	$68/ton
	2,500	$14,382	$176/ton	$44/ton

TABLE NOTES:

- Cost data are assumed to be in 2009$, based on E^C/R Incorporated analysis of vendor and industry group data for engines ranging from 50–3,000 hp (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 94% NOx removal efficiency.

Colorado requires emissions from rich-burn RICE greater than 500 hp be controlled using NSCR with an AFCR. This requirement applies statewide to engines for which control costs are below $5,000 per ton of NOx reduced.[38] In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the RICE Stationary Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[39] In its evaluation, Colorado reported that, "[f]ew of the statewide rich burn RICE demonstrated control costs exceeding the $5,000 cost off-ramp. Consequently, the state concluded that such NSCR controls are installed on the majority of rich burn RICE over 500 HP statewide."[40] Colorado further reports that "[n]one of the operators of rich burn RICE outside the [Denver] metro-area ozone non-attainment area submitted information demonstrating control costs in excess of $5,000 per ton cost threshold, consequently, the majority of natural-gas fired RB RICE over 500 HP must operate an NSCR with an AFR controller."[41]

Colorado's Reasonable Progress Evaluation for RICE listed the capital and annual operating costs for retrofitting existing engines with NSCR and an AFCR, which are reiterated in Table 3.

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[37] *See* Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010). Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.

[38] Colorado Regulation Number 7, *see* Section XVII.E.3.a.

[39] CDPHE RP for RICE.

[40] *Id.* at 4.

[41] *Id.* at 8.

Table 3. Capital and Operating Costs of NSCR with AFCR[42]

SOURCE CATEGORY	CAPITAL COSTS, 2003$*	ANNUAL OPERATING AND MAINTENANCE COSTS, 2003$*
RICH-BURN RICE > 500 hp	$35,000	$6,000
TABLE NOTES: *Colorado's cost estimates are from its "Denver Early Action Compact Analysis of Stationary Sources," dated 2003. Colorado does not specify, but it is assumed the cost data are from the 2003 timeframe.		

Colorado determined the annualized costs of control assuming a 15-year life of controls and indicating that, "[g]enerally the operational life of a catalyst is approximately 5 to 15 years, depending on factors such as how it is maintained and the particular duty cycle of the engine."[43] Colorado's use of a 15-year life of controls is also consistent with previous EPA analysis.[44] The annualized capital cost in Colorado's analysis of $4,851 appears to assume roughly a 10% interest rate, with total annualized costs – i.e., annualized capital costs plus annual operating and maintenance costs – of $10,851.[45] To be consistent with EPA's Control Cost Manual, which recommends the use of the bank prime interest rate, a lower interest rate than 10% is assumed in determining annualized costs of controls for this report.[46] As previously discussed, it is more appropriate to use a lower interest rate of 5.5%.[47] Thus, the cost data were revised to be consistent with the EPA's Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs.[48]

Colorado presented the cost effectiveness of retrofitting RICE greater than or equal to 500 hp with NSCR and an AFCR based on 2008 NOx emissions reductions for 305 RICE units located outside the nonattainment area of the state. However, the more generalized approach used in this report of assuming 94% control effectiveness is consistent with Colorado's requirement that these engines – controlled with NSCR and an AFCR – meet an emission limit of 1 g/hp-hr.[49] Again, using EPA's uncontrolled emission rate of 15.8 g/bhp-hr, the NOx emissions reduction efficiency of meeting a 1 g/hp-hr NOx limit for these engines is approximately 94%.[50]

The following table shows the cost effectiveness of a 500 hp RICE unit operating at 2,000 hours per year and at 8,000 hours per year and employing NSCR and an AFRC to meet a 1 g/hp-hr NO_x limit, based on a 15-year life and 5.5% interest rate.

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[42] *Id.*
[43] *Id.* at 10.
[44] EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).
[45] CDPHE RP for RICE at 8.
[46] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[47] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[48] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[49] *See* Colorado Regulation Number 7, *see* Section XVII.E.2.b.
[50] EPA 1993 Alternative Control Techniques Document for RICE.

Table 4. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC To Meet a 1 g/hp-hr NO_x Limit [51]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2003$
RICH-BURN	500	$9,487	$582/ton	$145/ton

TABLE NOTES:

- Cost data are assumed to be in 2003$, based on Colorado's Reasonable Progress Evaluation for the RICE Source Category.
- Analysis assumes 15-year life of controls and 5.5% interest rate.
- Analysis assumes 94% NOx removal efficiency.

NSCR for Smaller Rich-Burn RICE and Cyclically-Loaded RICE (< 500 hp)

California Air Districts have long been regulating NOx emissions from RICE, including engines smaller than 500 hp, and the California Air Resources Board (CARB) issued guidance to Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE.[52]

In the 1990s, when EPA first issued its Alternative Control Techniques document for stationary RICE, over 90% of all natural gas-fueled RICE were well pumps with an average size of 15 hp operating, on average, 3,500 hours per year.[53] Today, these smaller well pump engines likely make up a smaller share of nationwide RICE applications across the oil and gas industry, with continued growth in gas production and associated compression and processing applications. However, NOx emissions from these smaller pumping engines, on a regional scale, can be significant. For example, NOx emissions from artificial lifts (e.g., beam pumping used to push oil to the surface) in the New Mexico counties of the Permian Basin make up 13% of all NOx emissions.[54] The average rated horsepower of these engines is 21 hp and the magnitude of these NOx emissions – inventoried in 2014 – was close to 4,000 tons.

[51] *See* CDPHE RP for RICE. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.
[52] CARB 2001 Guidance.
[53] EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.
[54] IWDW 2014 Oil and Gas Emissions Inventories, *available at:* http://views.cira.colostate.edu/wiki/wiki/9170/2014-oil-and-gas-emissions-inventories.

CARB's 2001 guidance discusses RICE units derated[55] to less than 50 hp, indicating that, "[o]ne of the largest categories of the derated engines are cyclically-loaded units used to drive reciprocating oil pumps."[56]

Two specific concerns with respect to the applicability of NSCR to certain types of smaller pump engines used in the oil and gas sector include: (1) the impact that moisture and sulfur in the fuel have on the catalyst; and (2) the impact that variable engine loading has on maintaining sufficient temperatures. Some fuel gases contain high amounts of moisture and sulfur which can result in damage to (deactivation of) the catalyst. The sulfur content of pipeline-quality natural gas is low but some oil field gases can contain high sulfur concentrations. And in applications where engines are periodically idle or where the load is cyclical, it can be more difficult to maintain an adequate exhaust gas temperature. For example, for an oil well pump, the engine may operate at load for a time-period lasting from several seconds to around 20 seconds, followed by an equal amount of time idle. These limitations can generally be minimized through design and maintenance activities, e.g., by treating the field gas to reduce the moisture and sulfur content, heating the catalyst to avoid deactivation, thermally insulating the exhaust pipe and catalyst to maintain a proper temperature, etc.[57]

CARB recognized that these characteristics (e.g., cyclic loads and variable fuel composition) would, "tend to discourage the use of catalysts with air-to-fuel controllers." But CARB specifically noted that, "a review of source test data in [CARB's 2001 Guidance] indicates that there have been instances where these engines have been successfully controlled in the past by cleaning up the field gas, and 'leaning-out' the engine or installing a catalyst in some cases."[58]

Specifically, cyclic engines that drive certain oil pumps (e.g., beam- or crank-balanced pumping engines) fueled by oil field gas operate in a way that may adversely impact the effectiveness of NSCR control. Following are specific pump engine types, as defined in Santa Barbara County Air Pollution Control District (APCD) Rule 333 Control of Emissions from Reciprocating Internal Combustion Engines:[59]

> "Air-balanced pumping engine" means a noncyclically-loaded engine powering a well pump, with the pump using compressed air in a cylinder under the front of the walking beam to offset the weight of the column of rods and fluid in the well, eliminating the need for counterweights.

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[55] CARB describes a derated engine as, "one in which the manufacturer's brake horsepower rating has been reduced through some device which restricts the engine's output." CARB 2001 Guidance at IV-1.
[56] *See* CARB 2001 Guidance at IV-1.
[57] *Id.*; *also see* South Coast Air Quality Management District Preliminary Draft Staff Report for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (July 2019), D-4, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-pdsr_07172019.pdf?sfvrsn=6.
[58] *See* CARB 2011 Guidance at IV-1.
[59] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2, *available at:* https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.

"Beam-balanced pumping engine" means a cyclically-loaded engine powering a well pump, with the pump counterweight on the back end of the walking beam. The counterweight is moved mechanically without a cylinder supplying air pressure.

"Crank-balanced pumping engine" means a cyclically-loaded engine powering a well pump, with the pump counterweight attached to a gearbox which is attached to the walking beam with a pitman arm. The counterweight is moved mechanically, in a circular motion, without a cylinder supplying air pressure.

"Cyclically-loaded engine" means an engine that under normal operating conditions has an external load that varies by 40 percent or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines.

In Santa Barbara County APCD, cyclic rich-burn engines (beam- and crank-balanced pump engines) greater than 50 hp are expected to meet a NOx limit of 300 ppmv, corrected to 15% oxygen, by adjusting the A/F mixture (to operate lean) and properly tuning and maintaining the engines; these engines are not required to install add-on NSCR control. However, according to CARB's guidance, cyclic rich-burn engines have met emission limits as low as 50 ppmv (< 1 g/bhp-hr) by "using NSCR or by leaning the air/fuel mixture in conjunction with treating the field gas to reduce moisture and sulfur content."[60] Specifically, the following engine test data demonstrate emission rates under 50 ppmv (corrected to 15% oxygen) for pump engines:

Table 5. Pump Engine Test Data[61]

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE[62]	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
Santa Barbara	Air-balanced oil pumps	195 hp	NSCR	18	2-14
Santa Barbara	Beam- and crank-balanced oil pumps	131 hp	Leaning of A/F mixture	4	12-35
Santa Barbara	Beam- and crank-balanced oil pumps	39-46 hp	Leaning of A/F mixture	16	8-28
Santa Barbara	Beam- and crank-balanced oil pumps	39-49 hp	Leaning of A/F mixture	18	7-33
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	5	50

[60] *See* CARB 2001 Guidance at IV-5.

[61] *Id.*at IV-5 to IV-6.

[62] Oil pump engines, sometimes derated, are typically less than 50 hp, however there do appear to be some engines used for oil pumping applications that are larger, as shown in this table. And in addition, the underlying source test data in CARB's 2001 Guidance from Santa Barbara County and Ventura County also include a few data points for rich-burn engines less than 50 hp with NSCR, e.g., four 48 hp engines in Santa Barbara County with NSCR, and a 48 hp engine and 25 hp engine in Ventura County with catalyst control. *See* CARB 2001 Guidance Tables D-2 and D-3.

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE[62]	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	3	25
TABLE NOTE: the field gas used in these engines was either naturally low in sulfur or treated to pipeline-quality natural gas					

CARB concluded that, "[b]ecause of the demonstrated success of meeting the 50 ppmv NOx limit for cyclic rich-burn engines fueled by low-sulfur or treated field gas, we recommend that the districts consider the cost effectiveness of field gas treatment and emission controls in setting limits for these engines on a site-specific basis."[63] Essentially, CARB guidance proposed considering in its cost effectiveness analysis, the additional cost of field gas treatment including the material and labor costs of piping the treated fuel from the gas processing unit to the engine.

As of January 1, 2017, the San Joaquin Valley Air Pollution Control District (SJVAPCD) requires emissions from rich-burn RICE meet the following NOx limits:

Table 6. NOx Emission Limits for All Rich-Burn Non-Agricultural Operations Engines Rated at > 50 bhp[64]

ENGINE TYPE		NOx LIMIT [ppmvd corrected to 15% O2]	EQUIVALENT NOx LIMIT Converted to g/bhp-hr
4SRB	Cyclic Loaded, Field Gas Fueled	50	0.7
	Limited Use	25	0.4
	All other	11	0.2
TABLE NOTES: Conversions to g/bhp-hr limits are based on: 67 ppmv = 1 g/bhp-hr (per EPA's 1993 Alternative Control Techniques Document, page 4-11)[65]			

SJVAPCD completed a cost effectiveness analysis for the second phase of its internal combustion engine rule (Rule 4702) in 2003.[66] The District analyzed a broad array of control scenarios to meet these NOx limits including installing NSCR on both cyclic and non-cyclic rich-burn RICE of wide-ranging power output and capacity utilization.

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[63] *See* CARB 2001 Guidance at IV-6.
[64] SJVAPCD Rule 4702 Internal Combustion Engines, Tables 1 and 2, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.
[65] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), at B-3, *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.
[66] *Id.*

SJVAPCD found that the costs to install and operate NSCR at cyclically-loaded RICE units to meet the limit in Table 6 above were cost effective, with costs ranging from $394/ton to $20,272/ton (1999$), which reflected costs of NSCR assuming a 10-year life and a 10% interest rate.[67]

To use more current data on NSCR costs applied to cyclically-loaded units, the E^c/R cost equations provided in Section II.C. above were used to estimate cost effectiveness for cyclically-loaded RICE units. As previously stated, the E^c/R cost equations take into account the addition of an AFRC as well as the costs of the NSCR. It was assumed that the NSCR system would achieve 90% control of NOx at cyclically-loaded engines as is required by the Santa Barbara emission limit.[68] To reflect varying levels of operation, emission reductions were based on operating 2,000 hours per year, 4,500 hours per year, and 8,000 hours per year. Texas Commission on Environmental Quality (TCEQ) data for artificial lifts operating in the Permian Basin indicates that such units operate 4,380 hours per year, although a much higher annual hours of operation of 7,106 has been assumed for artificial lift engines in the Greater San Juan Basin.[69] Thus, to give a range of cost effectiveness of NSCR at cyclically-loaded units, cost effectiveness of NSCR was determined for a low, medium, and high number of operating hours per year. As with other NSCR cost effectiveness analyses, a 15-year life and a 5.5% interest rate were assumed. The results of this cost effectiveness analyses are presented in Table 7.

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[67] *Id.* at B-2 and at Table 3.
[68] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2.
[69] November 2016, RAMBOLL ENVIRON, San Juan and Permian Basin 2014 Oil and Gas Emission Inventory Inputs Final Report, at 25 and Appendix A at A-1, *available at*: https://www.wrapair2.org/pdf/2016-11y_Final%20GSJB-Permian%20EI%20Inputs%20Report%20(11-09).pdf.

Table 7. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn Cyclically-Loaded RICE Units with NSCR and AFRC, Based on EPA RICE NESHAP Cost Equations for NSCR[70]

ENGINE TYPE	SIZE (hp)	ANNUALIZED COSTS OF NSCR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 4,500 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,383/ton	$1,504/ton	$846/ton
	75	$5,396	$2,295/ton	$1,020/ton	$574/ton
	100	$5,489	$1,751/ton	$778/ton	$438/ton
	250	$6,045	$771/ton	$343/ton	$193/ton
	500	$6,971	$445/ton	$198/ton	$111/ton

TABLE NOTES:

- Cost data are assumed to be in 2009$, based on E^C/R Incorporated analysis of vendor and industry group data (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 90% NOx removal efficiency.

CARB's 2001 Guidance and the cost effectiveness analysis in this section for RICE units smaller than 500 hp show that application of NSCR to engines less than 500 hp can be cost effective. For RICE units used in oil pumping applications CARB describes situations where NSCR has been applied to cyclic rich-burn RICE to meet limits as low as 50 ppmv, citing certain types of "grasshopper" oil well pumps in Santa Barbara County.[71] And for oil pumping RICE units less than 50 hp CARB identified electrification (discussed in Section II.F, below), in addition to A/F adjustments and catalytic control, as technically feasible approaches to reducing NOx emissions from engines of this size.[72]

Further, SJVAPCD Rule 4702 for Internal Combustion Engines has a provision for RICE units at least 25 bhp, up to, and including 50 bhp that requires units that are sold after July 2012 to meet the applicable requirements and emission limits of EPA's NSPS for spark-ignition internal combustion engines in 40 CFR Subpart Part 60, JJJJ, for the year in which the ownership of the engine changes.[73] In the response to comments on its NSPS Subpart JJJJ rulemaking,[74] EPA provides many examples of the successful application of NSCR on small rich-burn engines and variable-load engines (noted as pumpjack engines or

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[70] *Id*. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and control efficiency of 90%.

[71] CARB 2001 Guidance at IV-5. "Source tests of NSCR-equipped cyclic engines in Santa Barbara County have shown that these engines can be effectively controlled with or without air/fuel controllers provided the oil well pumps are air-balanced units."

[72] CARB 2001 Guidance at II-1.

[73] SJVAPCD Rule 4702 Internal Combustion Engines Section 5.1

[74] 73 Fed. Reg. 3,568-3,614 (Jan. 18, 2008).

compressor engines) that justify its standards as achievable and demonstrated for very small rich-burn RICE.[75]

Application of NSCR to rich-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms in this section are of a cost basis that is from the 1999–2009 timeframe, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (67 ppmvd) and even lower NOx emission limits were cost effective to require such a level of control on existing rich-burn RICE. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The Chemical Engineering Plant Cost Index (CEPCI) has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[76] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of NSCR for rich-burn RICE include the following:

- 0 to 5% increase in fuel consumption resulting in increased CO_2 emissions[77]
- 1 to 2% reduction in power output[78]
- Increased solid waste disposal from spent catalysts.[79]

The impacts on increased fuel consumption and increased solid waste disposal are taken into account in the cost effectiveness analysis. Further, NSCR has been installed extensively on RICE units in the United States, and these non-air quality environmental and energy impacts are not generally considered to be impediments to implementing the control.

NSCR can be installed fairly quickly. The Institute of Clean Air Companies indicates that “off-the-shelf” NSCR converters can be installed in six to eight weeks. For NSCR installations that are more site-specific, NSCR can be installed in approximately fourteen weeks.[80]

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[75] *See* EPA’s Response to Public Comments on Spark-Ignition (SI) New Source Performance Standards (NSPS)/National Emission Standards for Hazardous Air Pollutants (NESHAP), posted to EPA’s docket on January 2, 2008, Docket ID EPA-HQ-OAR-2005-0030-0249, at 95-100, *available at*: https://www.regulations.gov/document?D=EPA-HQ-OAR-2005-0030-0249.

[76] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

[77] *See* EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.

[78] *Id.* Table 2-4 at 2-8.

[79] CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).

[80] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006 at 9, *available at:* https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

D. LEAN-BURN RICE: LOW EMISSION COMBUSTION (LEC)

Low emission combustion (LEC) retrofit kits are designed to achieve extremely lean A/F in order to minimize NOx emissions. The various retrofit technologies can include:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- AFRC[81]

According to EPA, "[n]ew spark-ignition engines equipped with LEC technology are, by definition, lean-burn engines."[82] A wide range of emission rates are achievable with LEC technology, with emissions generally no higher than 2 g/hp-hr and often significantly lower. EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[83] LEC is described by EPA in its Alternative Control Techniques Document, as follows:

> Low-emission combustion designs are available from engine manufacturers for most new SI engines, and retrofit kits are available for some existing engine models. For existing engines, the modifications required for retrofit are similar to a major engine overhaul, and include a turbocharger addition or upgrade and new intake manifolds, cylinder heads, pistons, and ignition system. The intake air and exhaust systems must also be modified or replaced due to the increased air flow requirements.
>
> Controlled NOx emission levels reported by manufacturers for [LEC] are generally in the 2 g/hp-hr (140 ppm) range, although lower levels may be quoted on a case-by-case basis. Emission test reports show controlled emission levels ranging from 1.0 to 2.0 g/hp-hr (70 to 140 ppmv). Information provided by manufacturers shows that, in general, BSFC decreases slightly for [LEC] compared to rich-burn designs, although in some engines the BSFC increases. An engine's response to increases in load is adversely affected by [LEC], which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.[84]

LEC NOx Removal Efficiency:	*87%*
Controlled NOx Emission Rates:	*1-2 g/hp-hr*
	70 to 140 ppmv

[81] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[82] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-3.
[83] *Id.* at 4-12.
[84] EPA 1993 Alternative Control Techniques Document for RICE.

In its Updated Information on NOx Emissions and Control Techniques Document for RICE, EPA states the following test data for LEC:

> In all, the sources of NOx emission test data [] include the results of 476 individual tests conducted on 58 engines. (This count does not include the aggregated data in some of the sources discussed [], such as the May 2000 EPA memo and the AP-42 sections.) In these tests, NOx emissions ranged from 0.1 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests measured NOx emissions greater than or equal to 4 g/bhp-hr.[85]

EPA also indicates that, "LEC is expected to be the most common control method for meeting the [1991 CARB Best Available Retrofit Control Technology (BARCT) for Stationary IC Engines], although SCR may be used as an alternative if LEC is unsuitable for a particular model engine."[86]

And according to the Interstate Natural Gas Association of America (INGAA), "LEC is the preferred approach to reduce lean-burn engine NOx emissions, but EPA or states may consider additional controls such as selective catalytic reduction (SCR)."[87]

EPA further states in its Updated Information on NOx Emissions and Control Techniques for RICE:

> Low-emission combustion retrofit equipment and services are generally available, particularly for the most plentiful engine models. Cooper Energy Services, maker of Cooper-Bessemer, Ajax, Superior, and Delaval engines provides CleanBurn™ retrofits for all of its larger models and offers these services for engines manufactured by other companies, as well. Dresser-Rand, manufacturer of Ingersoll-Rand, Clark, and Worthington engines also offers retrofit services for its lean-burn engines. The Waukesha Engine Division of Dresser Industries manufactures two engine families that are available either in rich-burn or LEC configurations. The company offers LEC retrofit services for those engines originally sold in the rich-burn configuration. At least three third-party vendors (Diesel Supply Company; Enginuity, Inc.; and Emissions Plus, Inc.) offer retrofit services for a wide variety of engine makes and models. These vendors will work with any model engine, although economies of scale can reduce capital costs for plentiful engines. For other engines, customized precombustion chambers can result in somewhat higher costs.[88]

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[85] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-9.
[86] *Id.* at 4-11.
[87] INGAA, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry (July 2014), *available at*: https://www.ingaa.org/File.aspx?id=22780.
[88] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-4.

California Air Districts have long been regulating NOx emissions from RICE, including lean-burn RICE. CARB issued guidance to Air Districts in 2001 on the reasonably available control technologies (RACT) and the best available retrofit control technologies (BARCT) for controlling NOx emissions from a broad range of stationary RICE.[89] In its analysis, CARB determined that LEC was a RACT level of control, and CARB set a NOx RACT limit of 125 ppmv.[90] CARB established a BARCT NOx limit for two- and four-stroke lean-burn engines rated at or higher than 100 hp of 65 ppmv or 90% reduction in NOx emissions.[91] CARB indicated that this lower NOx BARCT limit could also be met with LEC for many engines, although some engines might require some supplemental measures such as ignition system modifications and engine derating and others might require SCR to meet the BARCT NOx limit.[92] LEC can achieve 80 to 90% NOx reductions or even higher.[93]

The only exemptions CARB proposed from the NOx BARCT limit were for lean-burn engines rated less than 100 hp. With respect to these smaller engines, CARB determined that there are a relatively small number of such two-stroke lean-burn engines that cannot cost effectively install LEC or other NOx controls necessary to meet the NOx limits set for lean-burn RICE (both RACT and BARCT limits).[94] CARB described these engines as "located in gas fields statewide and [] used to drive compressors at gas wells."[95] CARB determined that, "the only cost effective way to control emissions from the[se] small two-stroke engines is by properly maintaining and tuning these engines which includes replacing oil-bath air filters with dry units and periodically cleaning the air/fuel mixer and muffler."[96] CARB ultimately recommend that the air districts, "require the replacement of these engines at the end of the two-stroke engine's useful life with prime movers having lower NOx emissions."[97]

CARB conducted cost effectiveness analyses for LEC on lean-burn RICE at a wide variety of engine power output ratings. CARB's analyses of capital and annual operating costs for retrofitting existing engines with LEC (and other NOx controls) were based on, "a mixture of quotes and extrapolations of cost from information provided by industry sources, associations, local governments, and the U. S. EPA."[98] CARB's cost data for LEC are presented in the table below.

[89] CARB 2001 Guidance.
[90] *Id.* at IV-6.
[91] *Id.* at IV.9.
[92] *Id.* at II-2, IV-10.
[93] EPA has said NOx reductions with LEC could be as high as 93%. *See* EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) at 5-67.
[94] *Id.* at II-2.
[95] *Id.* at IV-7.
[96] *Id.*
[97] *Id.*
[98] *Id*. at V-2.

Table 8. Capital Costs of LEC, 2001$[99]

POWER OUTPUT (hp)	LEC CAPITAL COSTS
50-150	$14,000
151-300	$24,000
301-500	$42,000
501-1,000	$63,000
1,001-1,500	$148,000

CARB calculated cost effectiveness for LEC assuming 80% NOx control, a 10-year life of the controls, and a 10% interest rate.[100] As previously discussed, to be consistent with EPA's Control Cost Manual which recommends the use of the bank prime interest rate, it is more appropriate to use a lower interest rate of 5.5%.[101] Thus, the CARB LEC cost data were revised to be consistent with the EPA's Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs. It must be noted that CARB's assumed 10-year life of LEC controls seems unreasonably short, as EPA has assumed a 15-year life of all controls for stationary internal combustion engines in other cost analyses.[102] Thus, the CARB LEC cost data were revised to assume a 15-year life of LEC controls.

CARB's cost analysis also assumed that the engines are run at rated power (100% load) for only 2,000 hours annually, which is equivalent to a capacity factor of roughly 25%. To reflect the cost effectiveness values for a range of operating hours, CARB's cost analysis was revised to reflect costs at 91% capacity factor, or 8,000 operating hours per year.

Last, CARB's cost effectiveness analysis only assumed an 80% NOx removal efficiency with LEC. As discussed above, an 80% NOx control efficiency is the low-end of NOx removal rates that can be achieved with LEC at lean-burn engines. CARB's BARCT limit is based on 90% NOx reduction. Thus, CARB's cost analyses were also revised to include cost effectiveness for 90% NOx control as well as 80% NOx control. These revised cost effectiveness calculations—assuming a 5.5% interest rate, 15-year life of LEC, capacity factors of 2,000 operating hours and of 8,000 operating hours, and both 80% NOx control and 90% NOx control—are presented in Table 9 below.

[99] *Id.* Note that the cost basis is not identified, and it is assumed to be 2001 dollars based on the date of the analysis. Also note that for engines with power output of 1,001-1,500 hp, a mid-range cost of $148,000 was assumed, similar to the assumption made by EPA when using CARB's cost data in its 2016 CSAPR TSD.
[100] CARB 2001 Guidance at V-4.
[101] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[102] EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

Table 9. Cost Effectiveness to Reduce NOx Emissions by 80%–90% from Lean-Burn RICE with LEC Operating at 2,000 and 8,000 Hours per Year[103]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF LEC, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 2,000 HOURS/YEAR, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 8,000 HOURS/YEAR, 2001$
LEAN-BURN	50	$1,857	$941/ton-$837/ton	$235/ton-$209/ton
	200	$3,184	$403/ton-$359/ton	$101/ton-$90/ton
	500	$5,572	$282/ton-$251/ton	$71/ton-$63/ton
	1,000	$8,358	$212/ton-$188/ton	$53/ton-$47/ton
	1,500	$19,635	$332/ton-$295/ton	$83/ton-$74/ton

The above analyses demonstrate that, with the exception of lean-burn engines rated at 50 hp that only operated 2,000 hours per year, the cost effectiveness of LEC at lean-burn engines is essentially between $80–$400/ton for a wide range of engine sizes and a wide range of operating hours.

In its Technical Support Document for Non-EGU NOx emissions for the CSAPR rule, EPA presented an equation for estimating the capital cost of LEC on natural gas lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from CARB's 2001 Guidance:[104]

$$\text{Capital cost} = \$16{,}019\ e^{0.0016 \times (\text{hp})}$$

Thus, the above equation can be used to estimate capital costs for LEC based on the hp rating of the unit. CARB did not identify any operating expenses with LEC, and thus the appropriate capital recovery factor can be multiplied by the results of the equation above for any size lean-burn engine to estimate annual costs of control with LEC.

CARB's cost estimates for LEC are relatively consistent with EPA's prior cost analyses of LEC lean-burn engines. For example, EPA's 1993 Control Techniques Document for RICE found the cost effectiveness for medium-speed engines operating at a 91% capacity factor was in the range of $310–$590/ton (1993$, assuming a 7% interest rate and a 15-year life).[105] EPA subsequently updated the cost information on LEC technology for lean-burn SI engines because "developments in LEC technology have brought retrofit costs down in recent years."[106] Specifically, in EPA's Updated Information on NOx

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[103] Cost information for LEC from CARB 2001 Guidance at Tables V-1 and V-2. Annualized cost of control assumed a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques for RICE (EPA-453/R-93-032).

[104] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-5. Note that the CSAPR TSD also presented an equation for annual costs, but it reflected annualized capital costs assuming a 7% interest rate and a 10-year life. Thus, the annualized cost equation is not provided here because it is not reflective of the current recommended interest rate for cost calculations of 5.5% or a 15-year life of controls.

[105] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-13 at 2-36.

[106] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-33.

Emissions and Control Techniques for RICE, its analysis of LEC retrofit for lean-burn SI engines showed, "cost effectiveness below $500 per ton of NOx reduced [in 1997$] for all engines larger than 2,000 bhp," which reflected an 80% capacity factor, 88% control, and a 7% interest rate. [107]

The 2001 CARB cost analyses for LEC is the most current comprehensive analyses for the costs of LEC available. It is recommended that the CARB cost data, as reflected in the equation given above (from EPA's CSAPR TSD), be used to calculate capital costs based on horsepower rating of an engine, assuming a 15-year life, 5.5% interest rate, and 90% NOx control. CARB's BARCT NOx limit of 125 ppmv should be considered as an achievable NOx emission limit with LEC at a lean-burn engine.

<u>Application of LEC to lean-burn RICE is cost effective for a wide range of engine sizes and types.</u>

While the cost estimates and cost algorithms in this section are of a cost basis that is close to twenty years old, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission rates reflective of LEC at lean-burn engines (<2 g/bhp-hr (150 ppmv)) have been considered as cost effective to require such a level of control on existing lean-burn RICE over 100 hp. This will be discussed further in Section II.G. below. For the reasons previously discussed in this report, it is not possible to accurately escalate these costs from 2001 to a current dollar basis. Nonetheless, the fact that numerous state and local agencies have imposed NOx limits that reflect the application of LEC demonstrates that it is a control that has been extensively retrofitted to existing lean-burn engines.

The environmental and energy impacts of LEC for lean-burn RICE are minimal and include the following:

- A decrease in fuel consumption of 0 to 5% resulting in decreased CO_2 emissions, as well as a corresponding decrease in emissions of other air pollutants[108]
- No effect on power output.[109]

E. LEAN-BURN RICE: SELECTIVE CATALYTIC REDUCTION (SCR)

Selective catalytic reduction (SCR) is an add-on (post combustion) NOx reduction technology that has been in use as early as the 1970s and has been applied to numerous source categories including stationary RICE units. In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described SCR systems as follows:

> Selective catalytic reduction is an add-on control technique that injects ammonia (NH3) into the exhaust, which reacts with NOx to form N2 and H20 in the catalyst reactor. The two primary catalyst formulations are base-metal (usually vanadium pentoxide) and zeolite. Spent catalysts containing vanadium pentoxide may be considered a hazardous material in some areas, requiring special disposal considerations. Zeolite catalyst formulations do not contain hazardous materials.

[107] *Id.* at 5-9.
[108] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.
[109] *Id.*

> Selective catalytic reduction applies to all lean-burn SI engines and can be retrofit to existing installations except where physical space constraints may exist. There is limited operating experience to date, however, with these engines. A total of 23 SCR installations with lean-burn SI engines were identified in the United States from information provided by catalyst vendors, in addition to over 40 overseas installations. To date [1993] there is also little experience with SCR in variable load applications due to ammonia injection control limitations. Several vendors cite the availability of injection systems, however, designed to operate in variable load applications. Injection systems are available for either anhydrous or aqueous ammonia. As is the case for NSCR catalysts, fuels other than pipeline-quality natural gas may contain contaminants that mask or poison the catalyst, which can render the catalyst ineffective in reducing NOx emissions. Catalyst vendors typically guarantee a 90 percent NOx reduction efficiency for natural gas-fired applications, with an ammonia slip level of 10 ppm or less. One vendor offers a NOx reduction guarantee of 95 percent for gas- fired installations. Based on an average uncontrolled NOx emission level of 16.8 g/hp-hr (1,230 ppmv), the expected controlled NOx emission level is 1.7 g/hp-hr (125 ppmv). Emission test data show NOx reduction efficiencies of approximately 65 to 95 percent for existing installations. Ammonia slip levels were available only for a limited number of installations for manually adjusted ammonia injection control systems and ranged from 20 to 30 ppmv. Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases slightly due to the backpressure on the engine caused by the catalyst reactor.[110]

There have been many advances in SCR systems and catalysts since EPA's 1993 Alternative Control Techniques Document. In 2012, the Ozone Transport Commission (OTC) issued a Technical Information Document on significant stationary sources of NOx emissions in the Oil and Gas Sector (hereinafter referred to as the "2012 OTC Report").[111] The OTC is a multi-state organization created under the CAA to address ozone problems in the Northeast and Mid-Atlantic U.S.[112] According to the 2012 OTC Report, many of the issues with variable load operation have been addressed by catalysts that have been designed to operate over a wide range of exhaust temperatures and for combustion devices with variable loads.[113] For example, in the 2012 OTC Report,[114] several vendors were listed that could provide such SCR systems and catalysts effective for the NOx control issues of lean-burn engines, such as Johnson Matthey,[115] Miratech Corporation which offers an SCR system for lean-burn engines used in natural gas compression,[116] CleanAir Systems which offers a lean-burn SCR called "E-Pod SCR" that is advertised to achieve up to 95% NOx reduction and reduce particulates, HC, and CO[117], and Caterpillar

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[110] EPA 1993 Alternative Control Techniques Document for RICE.
[111] *See* Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf.
[112] *See* https://otcair.org/about.asp.
[113] *See* 2012 OTC Report at 25-26.
[114] *Id.* at 26-27.
[115] *See* https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissions-control/selective-catalytic-reaction.
[116] *See* https://www.miratechcorp.com/products/cbl/.
[117] *See* http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf.

which offers SCR systems for several of its engines.[118] Although EPA's 1993 Alternative Control Techniques Document indicates achievable NOx emission rates of 1.7 g/hp-hr, the OTC identified NOx rates achievable with SCR at lean-burn engines of 0.2 to 1.0 g/bhp-hr, with the lower NOx rates achievable at four-stroke lean-burn engines and/or engines that also have some combustion control upgrades.[119] Moreover, two air districts in California—South Coast Air Quality Management District (SCAQMD) and SJVAPCD—have adopted NOx emission limits of 11 ppmv, which equates to 0.15 g/hp-hr, for lean-burn engines.[120] Based on this more recent information, the NOx reduction efficiency and achievable NOx emission rates are:

- *NOx Removal Efficiency:* *90-95+%*
- *Controlled NOx Emission Rates:* *0.15 to 1.0 g/hp-hr (11 to 73 ppmv)*

SCR can be applied to lean-burn spark-ignition engines, diesel compression-ignition engines, and dual-fuel compression-ignition engines. And while diesel engines are the most prevalent applications of SCR at RICE units, SCR has also been applied at lean-burn spark-ignition engines fired with natural gas, including at natural gas pipeline compressor stations.[121] Outside of the U.S., EPA stated in its 2000 update that "there are over 700 IC engines controlled with SCR systems in Europe and Japan, including approximately 80 to 100 2-stroke engines."[122] Thus, for those engines for which effective LEC retrofits are not available, SCR is available to achieve high levels of NOx control.

As previously stated, CARB issued guidance to California Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE.[123] For two- and four-stroke lean-burn engines greater than 100 hp, CARB set a BARCT limit 65 ppmv or 90% reduction in NO_x emissions.[124] CARB indicated that "[i]t is expected that the most common control method used to meet the BARCT emission limit [] will be the retrofit of low-emission combustion controls. Other techniques may also be used to supplement these retrofits, such as ignition system modifications and engine derating. For engines that do not have low-emission combustion modification

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[118] *See* https://www.cat.com/en_GB/search/search-results.html?search=selective+catalytic+reduction&pagePath=%252Fcontent%252Fcatdotcom%252Fen_GB%252Fproducts%252Fnew%252Fpower-systems%252Foil-and-gas.

[119] *See* 2012 OTC Report at 27-28 and 40-41.

[120] *See* SQAQMD Rule 1110.2, Table I and SJVAPCD Rule 4702, Table 2. The SCAQMD 11 ppmv limit applies to engines at facilities that are not in the Regional Clean Air Incentives Market (RECLAIM) as of January 5, 2018, and SCAQMD has indicated there are 18 engines currently meeting the 11 ppmv limit. *See* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/par1110-2-wg2-final.pdf?sfvrsn=6 at Slide 32. The SJVAPCD 11 ppmv limit does not apply to lean-burn engines used for gas compression, or those engines of limited use operation (less than 4,000 hours per year), or those engines that are waste gas-fuel—a higher limit of 65 ppmv applies to these engines.

[121] *See, e.g.,* EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-13.

[122] *Id.* at 4-13 (EPA notes, "[f]rom the context, we believe that the source of this last data meant 2-stroke lean-burn SI engines fired with natural gas, although it is not explicit in the reference.").

[123] *See* CARB 2001 Guidance.

[124] *Id.*

kits available, SCR may be used as an alternative to achieve the BARCT emission limits."[125] Thus, CARB envisioned that some RICE units would need to install SCR.

The SJVAPCD requires that emissions from lean-burn RICE meet the following NOx limits:

Table 10. SJVAPCD NOx Emission Limits for All Lean-Burn Non-Agricultural Operations Engines[126]

ENGINE TYPE		NOx LIMIT [ppmvd corrected to 15% O2]	EQUIVALENT NOx LIMIT [g/bhp-hr]
2SLB	Gaseous Fueled; >50 hp and <100 hp	75	1.0
4SLB	Limited Use	65	0.9
	Used for gas compression	65 or 93% reduction	0.9
	All other	11	0.15
TABLE NOTES: • Conversions to g/bhp-hr limits are based on EPA's Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (September 2000), where the conversion for uncontrolled lean-burn engines and lean-burn engines controlled with SCR is: 73 ppmv = 1 g/bhp-hr			

The 11 ppmv limit is clearly more stringent than CARB's recommended BARCT limit and thus presumably requires SCR to achieve at lean-burn RICE, possibly along with combustion modifications. SCAQMD adopted an 11 ppmv NOx limit for all RICE units unless located at a Regional Clean Air Incentives Market (RECLAIM) Facility, and thus SCAQMD has applied this lower NOx limit more broadly than the SJVAPCD.

The SJVAPCD completed a cost effectiveness analysis for the emission limits in the above table in 2003.[127] The District analyzed a broad array of control scenarios including installing SCR on lean-burn RICE of wide-ranging power output and capacity utilization and multiple applications (e.g., limited use, gas compression, etc.). SJVAPCD's report indicated that "[d]istrict staff feels that the annual compliance costs are reasonable for [all] five cases analyzed [including installation of a SCR system for a lean-burn engine]."[128] The report further concluded that "[a]lthough a few of the results indicated a high cost effectiveness, such results are due to the low emission reductions and not from high annual costs."[129]

SJVAPCD used the capital and annual operating costs for retrofitting existing engines with SCR based on CARB's 2001 guidance—which are based on installation of the more advanced parametric emissions

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[125] *Id.*
[126] SJVAPCD Rule 4702 Internal Combustion Engines, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.
[127] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.
[128] *Id.* at B-2.
[129] *Id.*

monitoring systems (PEMS) feedforward system controls, the use of urea as the reducing agent, and a catalyst sized to achieve 96% reduction in NOx emissions—as presented in the table below.

Table 11. Capital and Operating Costs of SCR[130]

POWER OUTPUT (hp)	INSTALLED SCR CAPITAL COSTS, 1999$	ANNUAL OPERATING AND MAINTENANCE COSTS, 1999$
50	$45,000	$20,102
200	$45,000	$26,102
500	$60,000	$35,102
1,000	$149,000	$78,102
1,500	$185,000	$117,102
TABLE NOTES: • The cost for the SCR is based on urea injection, with PEMS, and catalyst sized for 96% NOx conversion.		

SJVAPCD determined the annualized costs of control assuming a 10-year life of controls and a 10% interest rate.[131] As previously discussed, to be consistent with EPA's Control Cost Manual, a lower interest rate of 5.5% should be used for current cost effectiveness calculations.[132] With respect to the SCR equipment life, SCR systems can likely last much longer than 15 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.[133] To be consistent with EPA's statements on SCR, this report will assume a 20-year life for SCRs at lean-burn engines. Thus, a 5.5% interest rate and 20-year life of controls has been used for the revised SCR cost calculations presented herein.

SJVAPCD presented the cost effectiveness of retrofitting RICE with SCR based on reducing NOx emissions from a NOx rate of 740 ppmv to the proposed (and ultimately adopted) emission limit of 65 ppmv, which reflects a 91% control efficiency across the SCR. For RICE not already meeting NOx limits of 740 ppmv, employing SCR to reduce NOx emissions from what EPA considers to be the uncontrolled NOx emission rate of 1,230 ppmv (16.8 g/bhp-hr) to 65 ppmv corresponds to a NOx emissions reduction efficiency of 95%.[134] Such removal rates are achievable with SCR at lean-burn RICE, as discussed above.[135] However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not

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[130] *Id.* Table 5.
[131] *Id.* Table 2 and 3.
[132] EPA's Control Cost Manual recommends the prime lending rate be used to amortize capital costs, and the highest the bank prime rate has been in the past five years is 5.5%. *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[133] *See* EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[134] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[135] *See*, *e.g.*, 2012 OTC Rep at 19.

used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

SJVAPCD claimed to present cost effectiveness data for two different operating capacity factors: 25% and 75%. However, SJVAPCD also cited to CARB's cost analyses as the basis for SJVAPCD's assumed costs.[136] In the underlying cost effectiveness analysis, CARB assumed that the engines are run at rated power (100% load) for 2,000 hours annually, which is equivalent to a capacity factor of roughly 23%. It does not appear that SJVAPCD accounted for increased operating costs in its evaluation of costs at the higher capacity factor. Operating expenses at higher operating capacity factors would increase approximately by the ratio of the higher capacity factor (or operating hours) to the originally assumed capacity factor (or operating hours) in the original cost analysis.[137] The following table shows the cost effectiveness of retrofitting SCR to an uncontrolled lean-burn RICE operating at 2,000 hours per year and at 8,000 hours per year and meeting a 65 ppmv NO_x limit, based on a 20-year life and 5.5% interest rate. For the cost analyses shown in Table 12, SJVAPCD's operational costs were increased by a factor of four to more accurately reflect operational expenses at an operating capacity of 8,000 hours per year.

Table 12. Cost Effectiveness to Reduce NOx Emissions by 95% from 4SLB RICE with SCR Operating at 2,000 and 8,000 Hours per Year[138]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 1999$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 1999$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 1999$
4SLB	50	$24,585	$13,567/ton	$3,392/ton
	200	$30,585	$4,244/ton	$1,061/ton
	500	$41,080	$2,281/ton	$570/ton
	1,000	$92,946	$2,574/ton	$644/ton
	1,500	$135,533	$2,512/ton	$628/ton

As previously stated, the cost effectiveness presented in Table 12 above reflects compliance with the 65 ppmv NOx emission limit with SCR, which corresponds to a NOx emissions reduction efficiency of

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[136] *See* SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5, notes F and H.

[137] This is based on an analysis of varying hours of operation in EPA's SCR Cost Calculation Spreadsheet (06/2019) available on its Control Cost Manual website at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. While this spreadsheet is designed to estimate costs of SCR for fossil fuel-fired boilers, it can be used to estimate the increased in operational costs with increases in operating hours for any SCR system given that the SCR components are the same whether for a gas-fired boiler or a gas-fired RICE unit.

[138] *See* SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJAPCD's assumed 91% removal efficiency. Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

95%.[139] However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

More recently, EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls developed the following cost equations for SCR on natural gas four-stroke lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from SJVAPCD's 2003 cost effectiveness analysis:

Capital cost = $107.1 x (hp) + $27,186

Annual cost = $83.64 x (hp) + $14,718

The annual cost equation given above includes capital costs amortized assuming a 7% interest, which as discussed above is too high, and a 10-year equipment life, which should be 20 years as discussed above.[140] In the table below, the cost effectiveness of SCR based on these cost equations from EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls but revising the annual costs to reflect a 5.5% interest rate and a 20-year life of SCR and reflecting operations at 2,000 hours per year and at 8,000 hours per year. EPA's cost equations given above are based on an assumed 90% NOx reduction across the SCR,[141] so the same level of NOx control was assumed in the revised cost calculations presented in Table 13. Higher levels of NOx reduction and lower emission limits can be met with SCR alone or in combination with combustion controls. However, because higher levels of NOx reduction could also increase the operational expenses of SCR (unless some of the NOx reductions were achieved with combustion controls), the same 90% level of NOx control was assumed in the revised cost effectiveness analyses presented below to be consistent with the basis of EPA's cost equations.

[139] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[140] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-11 to 5-12.
[141] *Id.*

Table 13. Cost Effectiveness to Reduce NOx by 90% from 4SLB RICE with SCR Operating at 23% and 91% Capacity Factors, Based on EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls[142]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 2001$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 2001$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 2001$
4SLB	50	$17,509	$10,194/ton	$2,548/ton
	200	$29,368	$4,289/ton	$1,072/ton
	500	$53,086	$3,108/ton	$777/ton
	1,000	$92,617	$2,714/ton	$679/ton
	1,500	$132,148	$2,583/ton	$646/ton

Application of SCR to lean-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms are of a cost basis that is twenty years old, the cost data have been relied on extensively.[143] And, from at least 2001, it is important to note that several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (65 ppmvd) and even lower (as low as 11 ppmvd as required by SJVAPCD and SCAQMD) were cost effective to require such a level of control on existing lean-burn RICE rated greater than 100 hp. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[144] Further, the prices of air pollution control do not always rise at the same level as price inflation rates. As air pollution control is required to be implemented more frequently over time, the costs of air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of SCR for lean-burn RICE include the following:

- 0.5% increase in fuel consumption resulting in increased CO_2 emissions
- 1 to 2% reduction in power output[145]

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142 *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-12. Note that EPA assumes the cost basis is 2001$. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

143 EPA relied on the 2003 SJVAPCD Cost Effectiveness Analysis for Rule 4702 (which, in turn, relied on the 2001 CARB Guidance for Stationary SI Engines) in its 2016 EPA CSAPR TSD for Non-EGU NOx Emission Controls (Appendix A at 5-10 through 5-12).

144 EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.

145 *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.

- Increased solid waste disposal from spent catalysts[146]
- If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs.[147] If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply.

Regardless of these impacts, SCR technology is widely used at many industrial sources. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

In terms of length of time to install SCR at a lean-burn RICE unit, EPA has estimated that it takes 28–52 weeks to install SCR at a diesel-fired RICE unit.[148] It is reasonable to assume a similar time for the installation of SCR at a lean-burn natural gas-fired RICE unit.

F. RICE ELECTRIFICATION

Replacement of RICE with an electric motor is another pollution control option. In its 2001 guidance to California Air Districts, CARB indicated that electrification would be a NOx control option for RICE, with the potential to significantly reduce NOx emissions.[149] *Replacement of on-site engines with electric motors will reduce on-site NOx and other pollutant emissions by 100%.* Depending on the power source used for providing electricity to the site, air emissions may increase from the power generating site (i.e., if the power generating source is fueled by fossil fuels, rather than renewable energy such as wind or solar). However, even if the power is produced by a fossil fuel-fired power plant, it is likely more cost effective to a fossil fuel-fired power plant than it is to apply air pollution controls to individual engines.

CARB indicated in its 2001 guidance that "the majority of beam-balanced and crank-balanced oil pumps in California are driven by electric motors."[150] Thus, it stands to reason that electrification of such oil pumps is cost effective, given the widespread implementation.

CARB also found that electrification of RICE that fall within a size range from 50 to 500 hp would be a cost effective NOx control, but CARB stated that beyond the range of 50 to 500 hp, "modification and installation costs may become so extensive that this approach may not be cost effective."[151] However, on a cost per ton of NOx removed basis, CARB found that the electrification of engines in the 500 to 1,000 hp size range was as cost effective as the electrification of engines in the 50–150 hp size range –

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[146] *See* CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).
[147] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[148] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.
[149] CARB 2001 Guidance at I-7.
[150] *Id.* at IV-2.
[151] *Id.* at V-2.

that is, $1,100/ton in 1999 dollars.[152] For engines in the size range of 150 to 500 hp, electrification of engines was somewhat more cost effective at $900/ton in 1999 dollars.[153] CARB indicated that Air Districts in California should consider the replacement of engines with electric motors as a control option "whenever it is feasible in order to maximize emission reductions."[154]

It is important to note that CARB's cost effectiveness calculations were based the assumption of only 2,000 hours per year operation, and CARB assumed capital costs would be amortized over a 10-year period and at a 10% interest rate.[155] There is no basis for assuming such a short lifespan for an electric internal combustion engine. As discussed further above, gas-fired RICE units have a useful life of at least 30 years, and many have been in operation much longer than 30 years.[156] Had CARB assumed a 30-year life of controls, the annualized cost of a new electric compressor over 30 years would be significantly lower than CARB's assessment of those costs over 10 years. Further, for an engine that operates more than 2,000 hours per year, replacement with an electric engine will reduce more NOx emissions, which would also make the replacement of an engine with an electric engine more cost effective.

More recently, EPA's Natural Gas STAR Program issued a Fact Sheet which evaluated the methane-reduction benefits of replacing gas-fired reciprocating compressors with electric compressors.[157] According to EPA, "[t]he EPA's Natural Gas STAR Program provides a framework for Partner companies within U.S. oil and gas operations to implement methane reducing technologies and practices and document their voluntary emission reduction activities."[158]

The Fact Sheet documents the costs of replacing five existing gas-fired reciprocating compressors with four electric compressors.[159] This Fact Sheet was made available in 2011, and thus the cost basis is assumed to be either from 2010 or 2011. Specifically, the Fact Sheet indicates that a partner replaced two 2,650 hp reciprocating compressors, two 4,684 reciprocating compressors, and one 893 hp reciprocating compressor with four 1,750 hp electric compressors.[160] The Fact Sheet states that the total cost of the replacement was $6,050,000, including the cost of the motor and compressor.[161] The Fact Sheet calculated the cost of electricity as the primary operating expense, and the electricity costs assuming continual operation of the compressors throughout the year were estimated to be $6,800,000

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[152] *Id.* at V-3.
[153] *Id.*
[154] *Id.* at VII-2.
[155] *Id.* at V-4 to V-4.
[156] *See*, *e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950s to 1970s still operating at such facilities.
[157] *See* EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011, *available at*: https://www.epa.gov/sites/production/files/2016-06/documents/installelectriccompressors.pdf.
[158] *See* https://www.epa.gov/natural-gas-star-program/natural-gas-star-program.
[159] *See* EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011.
[160] *Id.* at 2.
[161] *Id.*

per year.[162] For electric compressors that operated less than every hour of the year, these operating costs can be scaled back by multiplying the projected electricity cost for continual operation by the ratio of the number of hours operated per year to 8,760 hours per year. Maintenance costs were assumed to be approximately 10% of the capital costs, and the maintenance costs would be lower than apply to gas-fired engines.[163] The Fact Sheet also presents the fuel gas savings for not having to pay for the natural gas to fire the reciprocating compressors based on three prices for natural gas ($3.00 per thousand cubic feet (MCF) of gas, $5.00 per MCF, and $7.00 per MCF).[164] The amount of natural gas saved by changing to electric compressors was estimated to be 1,700,000 MCF, assuming continual (8,760 hours) operation throughout the year and 20% efficiency of the gas-fired reciprocating compressors.[165] Because this analysis was focused on reducing methane emissions, no calculations of cost effectiveness of this control was done for NOx or any other pollutant.

With these data, the cost effectiveness of replacing similar-sized existing reciprocating compressor engines with similar-sized electric compressor engines as a NOx control measure can be calculated. For these calculations, it is assumed that the existing gas-fired reciprocating compressor engines are uncontrolled for NOx and thus emitting NOx at 16.8 g/bhp-hr.[166] To reflect compressor engines operating at varying hours per year, cost effectiveness calculations were done for replacing compressor engines operating at 2,000 hours, 4,000 hours, and 8,000 hours per year. The capital costs of the new electric compressors were amortized over a 30-year expected life of the new electric compressor engines, assuming a 5.5% interest rate consistent with EPA's Control Cost Manual methodology. The results of this analysis are provided in Table 14 below.

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[162] *Id.* This assumed that the four 1,750 hp compressor engines had 50% efficiency, operated 8,760 hours per year, and electricity cost $0.075/kW-hr.
[163] *Id.*
[164] *Id.*
[165] *Id.* A heating value of natural gas of 1,020 British Thermal Units (BTU) per standard cubic feet (SCF) of gas was also assumed.
[166] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.

Table 14. NOx Cost Effectiveness to Replace Natural Gas-Fired RICE Units with Electric Compressor Engines[167]

	Costs at Operating Hours per Year (2011 $)		
	2,000 hours/yr	**4,000 hrs/yr**	**8,000 hrs/yr**
Annualized Capital Costs of New Electric Engines	$506,385	$506,385	$506,385
Annual Operating Costs of New Engines and Excluding Costs of Gas for Replaced Engines	$992,940	$1,380,880	$2,156,761
Total Annual Costs	$1,887,265	$1,887,265	$2,663,146
NOx Removed, tpy	542 tpy	1,084 tpy	2,168 tpy
NOx Cost Effectiveness at Stated Hours/Year	$2,766/ton	$1,741/ton	$1,228/ton

Assumptions

- Existing Gas-Fired Reciprocating Compressor Engines: 2–2,650 hp, 2–4,684 hp, 1–893 hp
- Replacement Electric Compressor Engines: 4–1,750 hp
- Efficiency of Existing Gas-Fired Engines: 20%
- Efficiency of Electric Engines: 50%
- 30 Year Life of Electric Engines, 5.5% Interest Rate
- Cost of Electricity: $0.075 per kilowatt-hour; Cost of Natural Gas: $3.00/MCF[168]
- Annual Maintenance Costs: 10% of Capital Costs of New Electric Engines

The above cost effectiveness analysis does not take into account the increased emissions that may occur from the electric power generation that will power the new electric compressor engines, which will depend on the source of that power for the new electric engines. If the energy is provided by renewable sources, there will be no NOx, greenhouse gas, or other air pollution increase associated with the energy production. To take into account the increase in NOx from a fossil fuel-fired power plant providing the electricity to the electric compressor engines, a high-end estimate of the increase in NOx from fossil-fuel fired power plant would mean that the switch to electric engines would result in an overall NOx emission reduction of about 97% of the NOx emitted by the gas-fired reciprocating compressor engines (i.e., a power plant providing the electricity for the new electric compressor engines might increase NOx by 15 to 59 tons per year depending on the hours of operation of the new electric compressor

[167] The basis for the capital and operating costs are from EPA's PRO Fact Sheet No. 103 Install Electric Compressors.
[168] The $3.00/MSCF estimated cost of natural gas may overestimate natural gas prices. The EIA reported the Henry Hub Spot Price for 2019 to be $2.66/MCF and has projected the cost to stay similar or decrease slightly in 2020-2021. However, the Henry Hub spot price was higher ($3.27/MCF) in 2018. Further, the EIA lists the 2019 Industrial Sector price of natural gas to be $3.90. It is not clear which of these two prices would apply, and thus the assumed $3.00/MCF price of natural gas is a middle ground between these two prices. *See* https://www.eia.gov/outlooks/steo/report/natgas.php.

engines).[169] From the perspective of cost effectiveness, the potential increase in NOx emissions from the power generating source would not significantly impact cost effectiveness of replacing gas-fired engines with electric engines.

The costs in Table 14 assume that the engines are located relatively close to the power grid and thus do not take into account any costs to bring electricity to the site. For a site that is not relatively close to the power grid, CARB estimated it could cost $5,000 to $10,000 (in 1999 dollars) to set up the site for electric motor operation and states that some utilities may waive or refund those costs if monthly energy usage matches the cost to connect to the grid.[170]

There are many benefits associated with replacing gas-fired reciprocating compressor engines with electric compressor engines. Those benefits include: [171]

- Reduced maintenance requirements and costs.
- Electric engines are more efficient than gas-fired engines.
- Lower noise levels with electric motors compared to gas-fired engines.
- No on-site emissions of other air pollutants.

An additional benefit of replacing gas-fired engines with electric engines is the greenhouse gas reductions that would be achieved. With renewable energy accounting for a larger share of electricity production over time, there could be significant reductions in greenhouse gases by using electrified engines powered by renewable energy. In the EPA's Natural Gas STAR Program Fact Sheet for electric compressors, the gas savings by electrifying the compressors is stated to be 32,800 MCF per year.[172] With that amount of gas not being combusted in the compressor engines and the power for the compressor engines being supplied by renewable energy, there would be a decrease in greenhouse gas emissions of almost 2,000 tons per year.[173] With electric compression engines used, there also will be less methane released from compressor blowdowns. Compressors must be taken offline at times due to emergency upsets and due to maintenance. As previously stated, the maintenance requirements with an electric compressor engine are significantly less with electric compressor engines.[174] It also seems likely that an electric engine would be less prone to upsets that cause the engine to go offline, compared to a gas-fired reciprocating engine. Moreover, with no gas used in the compressor engine, fugitive emission leaks due to fuel gas are also eliminated. EPA's Natural Gas STAR Program Fact Sheet provided an estimate that methane emissions savings from replacing the five gas-fired compressor engines with electric engines could be as high as 16,000 MCF per year, based on a methane emission factor of 2.11

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[169] A NOx rate of 1.4 pounds per megawatt-hour was assumed for these calculations to represent a high-end estimate of the increase in NOx emissions if a fossil fuel-fired power plant provided the electricity for the electric engines. This reflects a NOx limit of 0.15 lb/MMBtu for a coal-fired power plant, which reflects a plant burning subbituminous coal with combustion controls. A natural gas-fired power plant would likely have a lower NOx rate, particularly if equipped with SCR.
[170] CARB 2001 Guidance at V-2.
[171] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.
[172] *Id.* at 1.
[173] Calculated based on EPA's greenhouse gas emission factors for natural gas combustion in Table C-1 of Subpart C of 40 C.F.R. Part 98.
[174] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.

MCF per horsepower.[175] Using the 100-year global warming potential identified by EPA,[176] that equates to roughly 10,000 tons per year of CO_2 equivalent emissions that would be avoided with no natural gas releases due to blowdowns with electric compressor engines. Thus, the total CO_2 equivalent emissions that could be reduced by replacing the five gas-fired engines with electric compressors powered with renewable energy would be about 12,000 tons per year.

There are several examples of electric engines being used in the oil and gas industry for compression, both at the wellhead and in compressor stations,[177] for drill rigs,[178] and in oil pumps.[179] Ambient air quality concerns have typically been the driver for electrification of engines in the past. Electrification of RICE units can be a very cost effective way to eliminate NOx and other air emissions, including greenhouse gas emissions, for the oil and gas industry and thus should be given serious consideration as an effective pollution control to address regional haze.

G. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED STATIONARY RICE UNITS

The NSPS standards applicable to stationary spark ignition gas-fired RICE units were last reviewed and revised in 2008.[180] The most stringent NOx limit of those standards currently in effect for new and modified spark ignition RICE units is 1.0 g/hp-hr for rich burn engines greater than 100 hp and for lean-burn engines between 100 hp and 1,350 hp.[181] In considering reasonable progress controls for gas-fired spark-ignition RICE units, the applicable NSPS standards should be considered the “floor” of potential NOx controls to consider for an existing RICE unit.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing spark-ignition gas-fired RICE units to meet, many of which have been in place for 10–20 years. In Table 15 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA’s 2016 CSAPR TSD,[182] which provided a summary of state NOx regulations for gas engines.[183] The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. A review of California Air District rules was also done for this report, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas-fired engines. We reviewed many of the remaining states’ regulations to determine whether there were NOx limitations for existing natural gas-fired stationary RICE units.

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175 *Id.* at 1.

176 *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why.

177 Armendariz, Al, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, prepared for Environmental Defense Fund, January 26, 2009, at 29-30, *available at*: https://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf.

178 *Id.* at 18.

179 CARB 2001 Guidance at IV-2.

180 *See* 40 C.F.R. Part 60, §60.4230(a)(5) and Subpart JJJJ. 73 Fed. Reg. 3568 (1/18/08).

181 40 C.F.R. Part 60, Subpart JJJJ, Table 1.

182 *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 14-15.

183 *Id.*

Table 15 is a summary of the NOx emission limits required of existing gas-fired stationary RICE units in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing RICE. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart JJJJ, the RICE did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing natural gas-fired stationary RICE units and generally required an air pollution control retrofit. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the $PM_{2.5}$ NAAQS. However, Colorado adopted a NOx limit for lean-burn RICE of 1 g/hp-hr as part of its initial regional haze plan to achieve reasonable progress towards the national visibility goal.[184] Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that numerous states and local governments have adopted NOx limitations that require NSCR at rich burn RICE units and either LEC or SCR at lean-burn RICE units. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD which require gas-fired RICE units greater than 50 hp in size to meet a 11 ppmvd (equivalent to 0.15 g/hp-hr) NOx limit.

These limits were adopted generally to meet reasonably available control technology (RACT) and best available retrofit control technology (BARCT — applies in California), and costs are taken into account in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls."[185] BARCT, on the other hand, is defined as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."[186] BARCT is like a best available control technology (BACT) determination under the federal prevention of significant deterioration (PSD) program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

Table 15. State/Local Air Agency RICE Rules for Natural Gas-fired Stationary RICE Units[187]

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA-Antelope Valley AQMD[188]	Rule 1110.2	Both	50–500 hp	45 ppmvd (0.67 g/hp-hr (RB) or 0.62 g/hp-hr (LB))
			>500	36 ppmvd (0.54 g/hp-hr (RB) or 0.49 g/hp-hr (LB))

[184] *See* CDPHE RP for RICE at 10.
[185] 40 C.F.R. § 51.100(o).
[186] HSC Code § 40406 (California Code), *available at*: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.
[187] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.
[188] https://ww3.arb.ca.gov/drdb/av/curhtml/r1110-2.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Portable	80 ppmvd (1.19 g/hp-hr (RB) or 1.10 g/hp-hr (LB))
CA-Bay Area AQMD[189]	Reg. 9, Rule 8	RB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	25 ppmv (0.37 g/hp-hr)
		LB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	65 ppmv (0.89 g/hp-hr)
CA-Mojave Desert APCD[190]	Rule 1160[191]	RB	>500 bhp &/or >100 hours/4 quarters, and only if located in the Federal Ozone Nonattainment area	50 ppmv (0.75 g/hp-hr)
		LB		140 ppmv (1.92 g/hp-hr)
		RB		50 ppmv (0.75 g/hp-hr)
		LB		125 ppmv (1.71 g/hp-hr)
CA-Sacramento AQMD[192]	Rule 412	RB	>50 bhp & exemptions for 50-525 hp if low op hours (200-40 hrs)	25 ppmv (0.37 g/hp-hr) Alt Limit: 90% NOx Reduction
		LB	>50 bhp	65 ppmv (0.89 g/hp-hr) Alt Limit: 90% NOx reduction
CA-Santa Barbara AQMD[193]	Rule 333	RB	>50 bhp Noncyclically-loaded[194]	50 ppmvd (0.75 g/hp-hr) or 90% NOx reduction
		RB	>50 bhp	300 ppmvd (4.48 g/hp-hr)

[189] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-8-nitrogen-oxides-and-carbon-monoxide-from-stationary-internal-combustion-engines/documents/rg0908.pdf?la=en.
[190] http://mdaqmd.ca.gov/home/showdocument?id=438.
[191] http://mdaqmd.ca.gov/home/showdocument?id=6631.
[192] http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf.
[193] https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.
[194] Noncyclically loaded means an engine that is not cyclically loaded. *See* Santa Barbara AQMD Rule 333.C.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Cyclically-loaded[195]	
		LB	>50 bhp & < 100 bhp	200 ppmvd (2.74 g/hp-hr)
		LB	≥100 bhp	125 ppmvd (1.71 g/hp-hr) or 80% NOx reduction
CA – San Diego AQMD[196]	Rule 69.4.1	RB	>50 bhp &>200 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		LB	>50 bhp &>200 hrs/yr	65 ppmvd (0.89 g/hp-hr)
CA-San Joaquin Valley APCD[197]	Rule 4702	RB	>50 bhp, Cyclic loaded, Field Gas Fueled	50 ppmvd (0.75 g/hp-hr)
		RB	>50 bhp & <4,000 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		RB	>50 bhp and all others (engines not waste gas-fueled or cyclic loaded or limited hours)	11 ppmvd (0.16 g/hp-hr)
		2SLB	>50 bhp & <100 bhp	75 ppmvd (1.03 g/hp-hr)
		LB	>50 bhp & <4,000 hrs/yr	65 ppmvd (0.89 g/hp-hr)
		LB	>50 bhp and used for gas compression	65 ppmvd (0.89 g/hp-hr) or 93% NOx reduction
		LB	>100 hp and not limited use (<4,000 hrs), not used for gas compression, or not waste-gas fueled	11 ppmvd (0.15 g/hp-hr)
	Rule 431	RB	>50bhp &>200 hrs/yr	50 ppmvd (0.75 g/hp-hr)

[195] "Cyclically-loaded" means "an engine that under normal operating conditions has an external load that varies by 40% or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines." *See* Santa Barbara AQMD Rule 333.C.

[196] https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules_and_Regulations/Prohibitions/APCD_R69-4-1.pdf.

[197] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA- San Luis Obispo APCD[198]				or 90% NOx Reduction
		LB	>50bhp &>200 hrs/yr	125 ppmvd (1.71 g/hp-hr) or 80% NOx Reduction
CA - SCAQMD[199]	Rules 1110.2 and 1100	RB & LB	>50 bhp	11 ppmvd (0.16 g/hp-hr (RB) 0.15 g/hp-hr (LB))
CA- Ventura County AQMD[200]	Rule 74.9	RB	>50 bhp & >200 hrs/yr	25 ppmvd (0.37 g/hp-hr) or 94% NOx reduction
		LB	>50 bhp & > 200 hrs/yr	45 ppmvd (0.62 g/hp-hr) or 90% NOx reduction
TX- Houston-Galveston-Brazoria Area[201]	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo	RB & LB	>50 hp	0.50 g/hp-hr (33 ppmvd (RB) 36 ppmv (LB))
TX- Dallas -Ft. Worth Area[202]	30 TAC 117.2110(1) Emission Specs for 8hr ozone demo	RB	>50 hp	0.50 g/hp-hr
		LB	In service before 6/1/07	0.70 g/hp-hr
		LB	Placed into service, modified, reconstructed, or relocated after 6/1/07	0.50 g/hp-hr
NJ[203]	Rule 7:27-19.8	RB	>500 bhp	1.5 g/bhp-hr
		LB	>500 bhp	2.5 g/bhp-hr

198 https://ww3.arb.ca.gov/drdb/slo/curhtml/r431.pdf.
199 http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf.
200 http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf.
201 https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.
202 http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110.
203 https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		LB & used for generating electricity	≥148 kW	1.5 g/bhp-hr or 80% NOx reduction
		2SLB	≥200 bhp & <500 bhp	3.0 g/bhp-hr
		4SLB	≥200 bhp & <500 bhp	2.0 g/bhp-hr
		RB&LB	Constructed or modified after 3/7/07, engines used to generate electricity with output ≥37 kW	0.90 g/bhp-hr or 90% NOx reductions (for modified units)
NY[204]	6 CCR-NY 227-2.4 (f)	RB & LB	>200 bhp	1.5 g/bhp-hr
MA[205]	310 CMR 7.19:(8)(c)	RB	>3 MMBtu/hr and >1,000 hrs	1.5 g/bhp-hr
		LB	>3 MMBtu/hr and >1,000 hrs	3.0 g/bhp-hr
MD[206]	COMAR 26.11.29.02.C.	RB	RICE used to compress nat gas ≥2400 hp	110 ppmv (1.64 g/hp-hr)
		LB	RICE used to compress nat gas ≥2,400 hp	125 ppmv (1.71 g/hp-hr)
CT[207]	22a-174-22e(d)(6a)	RB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
		LB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
IL (Chicago are and Metro East area)[208]	Title 35 Part 217, § 217.388a)1)	RB	Applies to specific engines listed in App G and those >500 bhp	150 ppmv (2.24 g/hp-hr)

[204] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[205] https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
[206] http://mdrules.elaws.us/comar/26.11.29.
[207] https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.
[208] http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		LB except Worthington engines not listed in App G	Applies to specific engines listed in App G and >500 bhp	210 ppmv (2.88 g/hp-hr)
		LB Worthington engines not listed in App G	>500 bhp & >8 MMbhp-hrs	365 ppmv (5.0 g/hp-hr)
GA (45 county area – ozone)[209]	Rule 391-3-1-.02.(2)(mmm)	RB & LB	≥100kW&<25 MW, in operation <4/1/00	160 ppmv (2.19–2.39 g/hp-hr)
	Applies only to engines used to generate electricity	RB & LB	≥100k W&<25 MW, in operation >4/1/00	80 ppmv (1.10–1.19 g/hp-hr)
MI[210]	R 336.1818	RB	>1 ton/day NOx engines per avg ozone control period day in 1995	1.5 g/bhp-hr
		LB		3.0 g/bhp-hr
CO[211]	Reg. No 7, Sections XVIII.E. 2 and 3	RB	>500 hp constructed before 2/1/09	Install and operate both a NSCR and an AFRC by 7/1/2010
		RB or LB constructed or relocated to Colorado ≥1/1/11	≥100 hp & <500 hp	1.0 g/hp-hr
		RB or LB constructed or relocated ≥7/1/10	≥500 hp	1.0 g/hp-hr
MT[212]	ARM 17.8.1603	RB engines at “oil and gas well facilities” (which does not include Compressor engines) which completed or modified	>85 bhp	Install and operate NSCR or its equivalent to control air emissions

209 http://rules.sos.ga.gov/GAC/391-3-1-.02.
210 https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf.
211 https://www.colorado.gov/pacific/cdphe/aqcc-regs.
212 https://deq.mt.gov/Portals/112/DEQAdmin/DIR/Documents/legal/Chapters/CH08-16.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		>3/16/79 and facility PTE NOx >25 tpy		
UT[213]	R307-510	Gas-fired engine at a well site that began operations, installed new engines or made modifications to existing engines after 1/1/16	≥100 hp	1.0 g/hp-hr

Most stringent NOx Limit of State/Local Rules:

11 ppmvd (0.15–0.16 g/hp-hr) applicable to either rich-burn or lean-burn RICE units greater than 50 bhp

In addition to the state and local air agency rules requiring NOx emission limits that clearly reflect highly effective NOx controls, some states have BACT or similar requirements that are required of new or modified sources regardless of whether or not such sources or modifications are major and subject to the major source PSD permitting programs. In some cases, states have issued guidelines on what is essentially considered BACT for these non-PSD new and modified sources, in the form of guidance and/or general permit or permit by rule requirements for RICE units. Table 16 below summarizes some of these state requirements which, when imposed in a permit would become binding emission limits.

[213] https://rules.utah.gov/publicat/code/r307/r307-510.htm.

Table 16. Other NOx Limits Applicable to Natural Gas-fired Stationary RICE Units

State	Determination	Applicability [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
NEW JERSEY[214]	State of the Art (SOTA) Emission Performance Levels	NO SIZE SPECIFIED	0.15 g/hp-hr (BOTH)[215]
PENNSYLVANIA[216]	Best Available Technology (BAT) Emission Limits for new SI RICE permitted on or after 8/8/18	≤100	1.0 g/hp-hr
		>100 TO ≤500	0.7 g/hp-hr (LB) 0.25 g/hp-hr (RB)[217]
		>500	0.5 g/hp-hr (LB) 0.2 g/hp-hr (RB)
		≥2,370	0.3 g/hp-hr uncontrolled (LB) **or** 0.05 g/hp-hr with control (LB)[218]
PENNSYLVANIA[219]	Best Available Technology (BAT) Emission Limits for existing SI RICE permitted on or after	≤100	2.0 g/hp-hr
		>100 TO ≤500	1.0 g/hp-hr (LB)

[214] NJ DEP State of the Art Manual for Reciprocating Internal Combustion Engines (2003), *available at*: https://www.state.nj.us/dep/aqpp/downloads/sota/sota13.pdf.

[215] Generally applied controls to meet State of the Art Emission Performance Levels:

Rich-burn: NSCR

Lean-burn: SCR or LEC

Basis: "In determining SOTA performance levels for RICE engines, permitting agencies, industry associations, manufacturers of RICE and manufacturers of emissions control equipment were contacted to obtain updated information on emissions and control technologies. Databases for recent permitted and tested engines from New Jersey, California and USEPA were reviewed." *Id.* at 8.

[216] PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Tables 8 and 9, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[217] PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Appendix C at 75, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[218] Lean-burn engines greater than or equal to 2,370 hp have a dual BAT: (1) engines with a NOx emission rate of 0.30 g/bhp-hr do not require SCR based on economic feasibility; and (2) engines with a NOx emission rate of 0.050 g/bhp-hr require SCR.

[219] *Id.*

State	Determination	Applicability [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
	2/2/13 but prior to 8/8/18		0.25 g/hp-hr (RB)[220]
		>500	0.50 g/hp-hr (LB) 0.20 g/hp-hr RB)
PENNSYLVANIA [221]	Best Available Technology (BAT) Emission limits for existing SI RICE permitted prior to 2/2/13	<1,500	2.0 g/hp-hr
WYOMING[222]	Oil and Gas Production Facilities Permitting Guidance Applicable to Natural Gas-Fired Pumping Units	≤50 hp AND MEETS BACT	2.0 g/hp-hr
TEXAS[223]	Oil and Gas Handling and Production Facilities Standard Permit RB engines manufactured on or after 1/1/2011; LB engines manufactured on or after 7/1/2010	≥100 bhp (RB) ≥500 bhp (LB)	1 g/bhp-hr

And in addition to the state guidance and/or general permit or permit by rule requirements for RICE units listed in Table 16, BACT analyses completed for PSD permits also demonstrate the feasibility of controls. As an example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC's

[220] PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Appendix C at 75, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[221] *Id.*

[222] WYDEQ Oil and Gas Production Facilities Permitting Guidance (last revised December 2018), *available at:* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf.

[223] TCEQ Air Quality Standard Permit for Oil and Gas Handling and Production Facilities (effective November 8, 2012), *available at:* https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf.

Rubart Station was determined to be SCR with a NOx BACT limit equivalent to 0.07 g/hp-hr for loads of 50% or higher.[224]

As Table 15 shows, twenty-three state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired stationary RICE units that reflect the application of NSCR to rich-burn natural gas-fired RICE units greater than 50 hp and LEC and/or SCR for lean-burn natural gas-fired RICE units greater than 50 hp. These air agencies have thus found that the levels of NOx control listed in Table 15, including NOx limits as low as 11 ppmvd, are cost effective for existing natural gas-fired RICE units, providing relevant examples of one measure for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. Further, several states have adopted essentially presumptive BACT NOx limits for new or modified RICE engines that are at least as stringent as the most stringent NSPS limit and/or apply to smaller units than the NSPS. The fact that these limits could apply to modified units means that the states consider retrofit controls to meet the emission limits in Table 15 above to be cost effective. Table 16 above also provides relevant examples of one measure for states to consider to prevent future impairment of visibility due to oil and gas development.

H. SUMMARY – NOx CONTROLS FOR EXISTING RICH-BURN AND LEAN-BURN NATURAL GAS-FIRED RICE

The above analyses and state/local rule data demonstrate that numerous state and local air agencies have found that NSCR is a cost effective NOx control for rich-burn natural gas-fired RICE units with costs ranging from $44/ton to $3,383/ton (2009$). NSCR not only reduces NOx, but can also be optimized with the use of an AFRC and an oxygen sensor to effectively reduce CO and HC and VOCs.

Further, numerous state and local air agencies have found that LEC is cost effective for lean-burn natural gas-fired RICE units with costs ranging from $74/ton to $941/ton (2001$). For the lowest NOx limit of 11 ppmvd applicable to lean-burn engines under rules adopted by SCAQMD and SJVAPCD, SCR was presumably necessary to meet these limits with costs ranging from $650 to $3,500 per ton of NOx removed or even higher for engines that operate 2,000 hours per year.

As states evaluate regulation of NOx emissions from natural gas-fired RICE units, there are several factors to consider, such as how the units are loaded (cyclically or not), operating capacity factor, and size. Nonetheless, given the numerous state and local NOx limits in Table 15 above that reflect operation of NSCR at rich-burn units and LEC or SCR at lean-burn units, these controls for rich-burn and lean-burn units rated at 50 hp or greater should generally be considered as cost effective measures available to make reasonable progress from natural gas-fired RICE units, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements. NSCR has the added visibility benefit of reducing VOCs, as well as NOx.

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[224] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.

It also must be recognized that it may be as or more cost effective for NOx control, and more beneficial for regional haze, to replace gas-fired RICE units with electric engines rather than install NOx pollution controls. Moreover, electric engines have numerous benefits that should be considered with regard to the energy and non-air impacts factor of a reasonable progress analysis. These additional benefits include reducing on-site emissions of all pollutants, reduced noise levels, more efficient operation and maintenance requirements (including less frequent maintenance required), and decreased methane emissions due to blowdowns because the electric engines do not require as frequent maintenance and do not have as many upsets. In addition, if the power for the electric engines can be derived from renewable energy sources, the greenhouse gas reductions can be very significant. Indeed, with renewable energy becoming an increasingly greater proportion of electricity generation and with coal-fired electricity generation being phased out, these added benefits of replacing gas-fired RICE units with electric engines should be considered in the four-factor analysis of controls. Electrification of engines may be less cost effective than some of the NOx controls evaluated above such as NSCR and LEC, but the potential added benefits with electric motors will likely weigh in favor of electrification as the most effective reasonable progress control for RICE.

III. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED RICE

VOC emissions from natural gas-fired RICE units result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates. In general, the emissions of VOCs from uncontrolled gas-fired RICE are of a lower magnitude compared to NOx emissions. A discussion of the pollution controls to reduce VOC emissions from these engines is provided below.

EPA's AP-42 Emission Factor documentation indicates that the uncontrolled VOC emission factors for natural gas-fired RICE in the range of 0.03 to 0.12 lb/MMBtu,[225] although it must be noted that EPA gives these emission factors a "C" rating. EPA's emission factor ratings indicate the reliability of the emissions factor, and a "C" rating reflects that "[t]ests are based on unproven or new methodology, or are lacking a significant amount of background information."[226] EPA also states that "actual emissions may vary considerably from the published emission factors due to variations in engine operating conditions."[227] That said, EPA's emission factors for uncontrolled VOCs are an order of magnitude lower than uncontrolled NOx emissions from RICE units. For that reason, this report focuses extensively on NOx emission controls for RICE units. However, there are emission controls feasible and implemented for VOCs from RICE units.

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[225] EPA, AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3, *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[226] EPA AP-42, Introduction at 8-9.
[227] EPA, AP-42, Section 3.2 at 3.2-3.

VOC Controls for Lean-Burn RICE

For lean-burn natural gas-fired RICE, as well as natural gas-fired combustion turbines, the primary method available for reducing VOC emissions is the use of an oxidation catalyst. For rich-burn RICE, NSCR is the pollution control of choice to address VOCs, as its three-way catalyst generally reduces NOx, CO, and VOCs with proper operation, although an oxidation catalyst can be installed downstream of the NSCR to improve VOC control.

A 2015 report issued by the Manufacturers of Emission Controls Association on emission controls for stationary internal combustion engines states as follows regarding oxidation catalyst for lean-burn engines:[228]

> Oxidation catalysts (or two-way catalytic converters) are widely used on diesel engines and lean-burn gas engines to reduce hydrocarbon and carbon monoxide emissions. Specifically, oxidation catalysts are effective for the control of CO, NMHCs, VOCs, and formaldehyde and other [hazardous air pollutants (HAPs)] from diesel and lean-burn gas engines. Oxidation catalysts consist of a substrate made up of thousands of small channels. Each channel is coated with a highly porous layer containing precious metal catalysts, such as platinum or palladium. As exhaust gas travels down the channel, hydrocarbons and carbon monoxide react with oxygen within the porous catalyst layer to form carbon dioxide and water vapor. The resulting gases then exit the channels and flow through the rest of the exhaust system.
>
> An oxidation catalyst has two simultaneous reactions:
>
> Oxidation of carbon monoxide to carbon dioxide:
>
> $$2CO + O_2 \rightarrow 2CO_2$$
>
> Oxidation of hydrocarbons (unburnt and partially burnt fuel) to carbon dioxide and water:
>
> $$C_xH_{2x+2} + [(3x+1)/2]O_2 \rightarrow xCO_2 + (x+1)H_2O$$

This 2015 report states that oxidation catalysts can reduce VOC emissions by 60–99%, as well as reduce CO emissions by 70–99%, non-methane HC by 40–90%, and formaldehyde and other hazardous air pollutants by 60–99%.[229] If a lean-burn engine is equipped with SCR for NOx control, an oxidation catalyst can be added to the SCR design.[230]

Cost information of oxidation catalyst was provided to EPA in 2010 to help determine national impacts associated with EPA's RICE NESHAP.[231] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for oxidation catalyst from industry groups, vendors, and manufacturers of RICE control

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[228] *See* Manufacturers of Emission Controls Association, Emission Control Technology for Stationary Internal Combustion Engines, Revised May 2015, at page 8, Section 1.2.1, *available at*: http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf.
[229] *Id.*
[230] *Id.* at 7.
[231] Memo from EC/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010).

technology. E^C/R Incorporated performed a linear regression analysis[232] on the oxidation catalyst cost data set for 2-stroke lean-burn engines and for 4-stroke lean-burn engines to establish an equation for each type of engine to estimate total annual cost and total capital costs as follows:

2SLB Oxidation Catalyst Total Annual Cost = $11.4 x HP + $13,928

2SLB Oxidation Catalyst Total Capital Cost = $47.1 x HP + $41,603

4SLB Oxidation Catalyst Total Annual Cost = $1.81 x HP + $3,442

4SLB Oxidation Catalyst Total Capital Cost = $1.81 x HP + $3,442

Where HP equals the engine size in horsepower.

E^C/R Incorporated developed equations to reflect total annual costs oxidation catalyst assuming a 7% interest rate and a 10-year life for amortizing the capital costs of control and adding in the annual operation and maintenance costs.[233] For the same reasons discussed regarding NSCR in Section II.C. above, it is reasonable to assume a 15-year life of oxidation catalyst controls at lean-burn RICE. Further, a lower interest rate of 5.5% is the appropriate interest rate to currently apply pursuant to the recommendations of EPA's Control Cost Manual for determining annualized capital costs of oxidation catalyst. Table 17 below provides the capital costs for oxidation catalysts at various size gas-fired lean-burn RICE and the total annualized cost of the control, assuming a 5.5% interest rate and a 15-year life.

Table 17. Capital and Annual Costs of Oxidation Catalyst at Lean-Burn RICE.[234]

ENGINE TYPE	HORSEPOWER	TOTAL CAPITAL COSTS	TOTAL ANNUALIZED COSTS
2SLB	50	$43,958	$12,619
	75	$45,136	$12,853
	100	$46,313	$13,088
	250	$53,378	$14,496
	500	$65,153	$16,843
	1000	$88,703	$21,536
	1500	$112,253	$26,229
4SLB	50	$3,533	$3,381
	75	$3,578	$3,425
	100	$3,623	$3,468
	250	$3,895	$3,727
	500	$4,347	$4,160
	1000	$5,252	$5,025
	1500	$6,157	$5,890

[232] *Id.* at 5-6.
[233] *Id.* at 5-6 and Appendix A.
[234] Cost calculations based on E^c/R equations from above, but assuming a 15-year life and a 5.5% interest rate.

A 2019 report by SCAQMD indicates that 500 stationary lean-burn engines have been fitted with oxidation catalyst.[235] In Colorado, sixty lean-burn RICE of sizes greater than 500 hp were required to install oxidation catalyst under the 2004 Denver Early Action Compact rulemaking.[236] As of July 1, 2010, Colorado requires all existing lean-burn RICE greater than 500 hp in the state's ozone action areas to install and operate an oxidation catalyst with an emission performance standard of 0.7 g/hp-hr.[237] Colorado only exempted lean-burn engines in the Denver area from the requirement to install oxidation catalyst if the cost was greater than $5,000/ton.[238] There are also several examples of oxidation catalyst being required as BACT for VOCs for lean-burn RICE. For example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC's Rubart Station was based on good combustion practices and an oxidation catalyst with a VOC BACT limit equivalent to 0.2 g/hp-hr for loads of 50% or higher.[239] In another example, BACT for RICE at the Irving Generating Station in Arizona was based on use of an oxidation catalyst with a VOC BACT limit (less formaldehyde) of 0.7 g/hp-hr.[240] In the BACT analysis for the Irving Generating Station several other recent examples were presented demonstrating consistent VOC BACT limits for natural gas-fired RICE, including limits as low as 0.3 g/hp-hr.[241]

In summary, oxidation catalyst is an available control technology that should be considered as a reasonable progress control option to reduce VOC emissions for lean-burn gas-fired RICE.

VOC Controls for Rich-Burn RICE

As discussed in Section II.C. above, NSCR is a three-way catalyst applicable to rich-burn RICE units, which not only removes NOx emissions, but also reduces CO and VOC emissions. In addition to the NSCR catalyst and housing, NSCR requires installation of an oxygen sensor and an AFRC ensure optimum air-to-fuel ratios to ensure conditions are NSCR is the primary VOC control that is implemented for rich-burn gas-fired RICE. Colorado has indicated that an "oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control."[242] The costs for NSCR have been detailed above in Section II.C. NSCR's cost effectiveness for NOx control and its widespread required use, as shown in the state and local air agency rules detailed in Table 15 above, indicates that NSCR must be considered as a reasonable progress control option to reduce VOC emissions from rich-burn RICE.

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[235] SCAQMD, Draft Staff Report, Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, September 2019, at D-1, *available at*: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-draft-staff-report---final.pdf?sfvrsn=6.

[236] *See* CDPHE RP for RICE at 3. *See also* Colorado Regulation No. 7, Part E, Section I.B., *available at*: https://drive.google.com/file/d/16qTQLSTX1T49DYWp3voXRNl4_g-vbhQT/view.

[237] Colorado Regulation 7 (5 CCR 1001-9) Part E 1. Control of Emissions from Engines.

[238] *Id.* at Section I.C.4. of Part E.

[239] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.

[240] Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irving Generating Station, Tucson Electric Power (2017), *available at*: https://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/17-12-19-Sundt-RICE-Project-Revised-Application.pdf.

[241] *Id.* Table 5-3 at 5-10. Showing sources from Texas, Oregon, Kansas, and Hawaii receiving permits between 2013 and 2016.

[242] CDPHE RP for RICE at 6.

IV. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

Natural gas-fired combustion turbines are used in the oil and gas development industry generally for two purposes: (1) power generation and (2) compression. Combustion turbines are sometimes used to provide on-site power to gas processing facilities, or combustion turbines are used to drive compressors. There are several points in the oil and gas production process where compression of the natural gas is required to move the gas in the pipeline. When a combustion turbine is used for gas compression, the turbine drives the compressor, which is typically a centrifugal compressor. [243]

Gas turbines have been used for power generation since the late 1930s and are available in sizes as low as 500 kilowatts (kW) to over 300 Megawatts (MW).[244] Gas turbines produce a high-heat exhaust that can be recovered in a combined heat and power to produce steam to power a generator. This process is referred to as combined cycle power generation. However, in the oil and gas production industry, gas turbines are generally operated in simple cycle mode. Gas turbines can be used in remote locations such as oil and gas wellfields to provide distributed generation and portable power generation.[245] In some cases, combustion turbines are used at power plants developed for the purpose of providing power to oil and/or gas development but which are also selling electricity to the grid. If a power generating source is constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale, then it is considered an electric utility.[246] Although this specific analysis of controls will focus on the gas turbines used for gas compression or used for on-site power (i.e., “distributed generation”) at oil and/or gas production and processing facilities, the available air pollution controls are the same for simple cycle turbines regardless of whether or not such turbines are part of an electric utility.

When combustion turbines are used to drive a compressor, there is no electrical generator (although there could be some heat recovery which could be used to generate electricity through a steam turbine).[247] Instead, the turbine shaft power is used as mechanical power to drive a compressor. Regardless of the purpose of the gas-fired combustion turbines, the air pollution controls for the associated visibility-impairing pollutants are the same.

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[243] *See*, *e.g.*, 76 Fed. Reg. 52,738 at 52,761 (Aug. 23, 2011); *see also* Innovative Environmental Solutions, Inc. & Optimized Technical Solutions, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry, July 2014, at 26, note 1, *available at*: https://www.ingaa.org/File.aspx?id=22780.

[244] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-1, *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.

[245] *Id.* at 3-2.

[246] 40 C.F.R. § 60.331(q).

[247] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at S-2, 3-6, and A-2.

The 2012 Ozone Transport Commission Report refers to a report on costs of NOx controls at gas turbines prepared for the U.S. Department of Energy (DOE) in 1999.[248] That DOE Report, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" dated November 5, 1999 (hereinafter "1999 DOE Report")[249] is cited in several EPA and state documents on the cost of NOx controls at gas turbines, including in a Northeast States for Coordinated Air Use Management (NESCAUM) 2000 Status Report on NOx Controls for gas turbines and other sources,[250] which, in turn, serves as EPA's primary reference for the cost of SCR in its recently revised SCR chapter in its Control Cost Manual.[251] The NESCAUM 2000 Status Report on NOx controls also has other cost information for NOx controls for gas turbines. While these reports are twenty years old, the cost analyses have been relied on extensively by EPA and states.[252] In addition, more recent analyses of the costs of NOx controls for gas turbines have been summarized as supporting information for state and local air agency adoption of NOx emission limitations for gas turbines, but those cost analyses are generally not as detailed as the 1999 DOE report. In the discussion below of the NOx pollution control options for gas turbines, we provide information on all of these various cost analyses.

Note that in the following discussion, NOx emission rates are often referred to as parts per million or "ppm." It should be assumed that such concentration rates are in parts per million by volume or "ppmv" measured on a dry basis and corrected to 15% oxygen unless stated otherwise.

A. WATER OR STEAM (DILUENT) INJECTION

Water or steam injection has been used for decades to reduce NOx emissions from gas turbines. EPA describes the control in its "AP-42" emission factor documentation for gas turbines as follows:

> Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.
>
> Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required

[248] *See* 2012 OTC Report at 66-67.
[249] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, Appendix A at A-5 (Table A-4), *available at*: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf.
[250] NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness, at III-21 through III-24 and at III-40 [hereinafter "NESCAUM 2000 Status Report"], *available at*: http://www.nescaum.org/documents/nox-2000.pdf/view.
[251] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf 12 and 98 (reference 19).
[252] EPA relied on the cost analyses in the 1999 DOE Report for the Cross-State Air Pollution Rule. *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-10 through 3-18.

> to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.[253]

The 1999 DOE Report on NOx pollution controls for gas turbines indicates that water or steam injection can achieve a NOx rate of 42 ppm.[254] In a more recent document, EPA states that water or steam injection enables a gas turbine to achieve NOx levels of 25 ppm at 15% oxygen.[255] General Electric also indicates that water injection can reduce NOx emissions to 25 ppm for gas-fired turbines.[256] The achievable NOx rate with water or steam injection likely depends on the uncontrolled NOx rate before water or steam injection, which can vary by turbine size and manufacturer.

Water injection has been a commonly applied retrofit NOx control technology for gas turbines for several decades. Water injection is available to most turbines; however, with advances in dry low NOx combustion techniques (discussed in the next section), it is not necessarily the first NOx control of choice given the lower cost and more effective options being available, depending on the turbine type. The turbine modifications necessary to accommodate water or steam injection could range from replacement of fuel nozzles with nozzles capable of supplying both fuel and water or steam, to replacement of the combustors with combustors designed to operate with water or steam injection, depending on the make and model of the combustion turbine.[257] There would also be other required equipment such as appropriate combustion turbine controls, an onsite water plant to demineralize water with storage or a storage tank for delivered demineralized water, a water injection pump, and a water or steam flow metering station.[258]

The 1999 DOE Report listed the capital and annual operating costs for water injection installed at specific makes/models of combustion turbines, which are reiterated in the table below.

Table 18. Capital and Operating Costs of Water or Steam Injection for Select Combustion Turbines[259]

Turbine Make/Model	Size, MW	Size, hp	Capital Costs of Water/Steam Injection 1999$	Annual Costs (Excluding Capital Recovery), 1999$
Solar Centaur 50	4.2 MW	5,632 hp	$405,500	$79,000
Allison 501-KB5	4.0 MW	5,364 hp	$291,000	$100,000
GE LM2500	22.7 MW	30,441 hp	$1,083,175	$294,000
GE MS7001F	161 MW	215,904 hp	$4,834,770	$1,325,000

[253] EPA, Compilation of Air Pollutant Emission Factors (AP-42), Section 3.1 Gas Turbines, April 2000, at 3.1-6.
[254] 1999 DOE Report, Appendix A at A-5 (Table A-4).
[255] EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[256] *See* GE Power, Water Injection for NOx Reduction, at https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction.
[257] 2012 OTC Report at 62.
[258] *Id.*
[259] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4).

The 1999 DOE report determined the annualized costs of control assuming only a 15-year life of controls and a 10% interest rate.[260] The DOE report provides no discussion as to why it assumed a 15-year life of controls, other than to state that EPA used the same 15-year life in a 1993 NOx control document.[261] There is no documented justification for assuming a 15-year life of water or steam injection controls for a combustion turbine. Instead, it is reasonable to assume that the design life of a combustion control like water or steam injection at a gas-fired combustion turbine is equal to the design life of the combustion turbine. A literature review indicates that 25 to 30 years is the design life of a gas combustion turbine.[262] Indeed, a review of permitted compressor stations and gas processing facilities in the state of New Mexico shows several combustion turbines operating today that were installed more than 30 years ago.[263] For the purpose of determining the annualized cost of controls, an assumption of a 25-year life of a water or steam injection system is more than reasonable and justified. Thus, to determine annualized costs based on the capital and operational expenses for water/steam injection presented in Table 18 above, a 25-year life of controls was assumed. Further, to be consistent with EPA's Control Cost Manual, which recommends the use of the bank prime interest rate,[264] a lower interest rate of 5.5% was assumed.[265] In its 2019 cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA used an interest rate of 5.5%.[266] The annualized costs of controls are presented for the four turbine types in Table 19 below.

The 1999 DOE Report calculated cost effectiveness of water or steam injection for the four turbine models listed in Table 18 above based on achieving a NOx rate of 42 ppm.[267] EPA relied on these cost estimates in its 2016 Technical Support Document for the Cross-State Air Pollution Rule regarding non-EGU NOx emissions controls, stating that the "generally accepted threshold" NOx emission rates that can be achieved with water injection was 42 ppmvd.[268] In its 2016 TSD for the CSAPR rule, EPA did not escalate the costs of controls from 1999 dollars.[269] As discussed above, lower NOx rates with water or steam injection of 25 ppm are generally achievable. Thus, in Table 19 below, the cost effectiveness of

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[260] *Id.* at 3-1. *See also* EPA's January 1993 Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (EPA-453/R-93-007) at 6-222 [hereinafter referred to as "1993 ACT for Stationary Gas Turbines"].

[261] In the 1993 NOx control document, EPA also assumed a 15-year life for SCR, when now EPA assumes a 20 to 30-year life of SCR systems, depending on the application. *See,* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 80.

[262] *See*, *e.g.*, Sargent & Lundy Combined-Cycle Plant Life Assessments, *available at*: https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf; GE Power Generation, GE Gas Turbine Design Philosophy, *available at*: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-3434d-ge-gas-turbine-design-philosophy.pdf; NREL, Annual Technology Baseline, Natural Gas Plants, *available at*: https://atb.nrel.gov/electricity/2018/index.html?t=cg; Solar Turbines, Industrial Power Generation, Taurus 70, Benefits and Features, *available at*: https://www.solarturbines.com/en_US/products/power-generation-packages/taurus-70.html.

[263] *See* Title V air operating permits for Chaco Gas Plant, Pecos River Compressor, and Kutz Canyon Gas Plant, among others, available on the New Mexico Environment Department's website.

[264] US EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

[265] *See e.g.*, https://fred.stlouisfed.org/series/DPRIME.

[266] *Available at* https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[267] *Id.* at A-3

[268] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls, November 2015, Appendix A at 3-10 through 3-12.

[269] *Id.*

water/steam injection is calculated both to comply with a 42 ppm limit and a 25 ppm limit, based on a 25-year life and a 5.5% interest rate.

Table 19. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 91% Capacity Factor[270]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$109,230	$1,496/ton	$1,265/ton
Allison 501-KB5	4.0	5,364	$121,694	$1,323/ton	$1,153/ton
GE LM2500	22.7	30,441	$374,750	$846/ton	$752/ton
GE MS7001F	161	215,904	$1,685,429	$409/ton	$373/ton

In sum, the cost effectiveness of water or steam injection at a gas-fired turbine is in the range of $1,150-$1,500/ton for the smaller turbines, $750 to $850/ton for a mid-sized turbine, and $375 to $410 for a large turbine. It must be noted that this cost effectiveness analysis is based on an assumed 8,000 hours of operation per year.[271] A 2012 document of technical information on the oil and gas sector available on the Ozone Transport Commission's website indicates that "on average a compressor unit will tend to experience an annual average capacity factor of approximately 40%."[272] This is presumably an average across all compressor engines used in the oil and gas sector, and there are very likely some compressors that do operate at 90% capacity factors. Indeed, the Ozone Transport Commission document indicates that "[f]or many mainline natural gas compressor stations, industry data indicated that the gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity."[273] Given that a compressor station typically is composed of multiple compressors either in parallel or in series powered either by combustion turbines or by reciprocating engines, it seems very likely that one or more of the compressors at a compressor station would operate at a high capacity factor while others would be operated at lower capacity factors, depending on the volume of gas that is being moved through the pipeline at the time. To provide a complete analysis of the range of costs of water or steam injection at a gas-fired combustion turbine, the cost effectiveness analysis of the 1999 DOE Report was revised to reflect a 40% capacity factor. Specifically, the fuel penalty cost (due to the reduction in turbine efficiency with water injection) and all costs dependent on the gallons of water used per year (i.e., the

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[270] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed, reflective of the assumed 8,000 hours of operation per year in the November 1999 DOE Cost Analysis report.

[271] *Id.*, Appendix A at A-5.

[272] 2012 OTC Report at 16.

[273] *Id.*

water costs, water treatment costs, associated labor costs, and water disposal costs) in the annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor.[274] Also, the tons of NOx reduced per year were revised to reflect operations at a 40% capacity factor.

Table 20. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 40% Annual Capacity Factor[275]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$85,649	$2,675/ton	$2,257/ton
Allison 501-KB5	4.0	5,364	$90,021	$2,232/ton	$1,940/ton
GE LM2500	22.7	30,441	$255,506	$1,316/ton	$1,166/ton
GE MS7001F	161	215,904	$1,060,507	$587/ton	$533/ton

EPA's 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of water injection based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, but still high compared to today's interest rates.[276] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule are reprinted below.[277]

<u>Water Injection/Gas Turbines:</u>

Total Capital Investment (1999 dollars) = 27665 x (MMBtu/hr)^0.69

Total Annual Costs (1999 dollars) = 3700.2 x (MMBtu/hr)^0.95

<u>Steam Injection/Gas Turbines:</u>

Total Capital Investment (1999 dollars) = 43092 x (MMBtu/hr)^0.82

Total Annual Costs (1999 dollars) = 7282 x (MMBtu/hr)^0.76

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[274] It is possible that other items in the annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.

[275] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed. The annual costs due to the fuel penalty, water use, water treatment, associated labor, and water disposal were decreased by 56% to reflect a 40% operating capacity factor as opposed to a 91% capacity factor.

[276] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11 to 12 and Appendix B at B-2.

[277] *Id.,* Appendix A at 3-12.

While the cost estimates and cost algorithms are of a cost basis that is from 1999, it is important to note that beginning in the mid- to late-1990s, EPA and several state and local air agencies have found that the costs of control to achieve NOx emission limits of 42 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below. It is not possible to accurately escalate these costs in 1999 dollars to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[278] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. Moreover, as an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Thus, the costs for water or steam injection are presented on a 1999 dollar cost basis in this report, but in any event, Table 29 in Section IV.D. of this report shows that numerous state and local air agencies found that water or steam injection was cost effective to require as a retrofit NOx pollution control at numerous gas turbines.

The environmental and energy impacts of the use of water or steam injection include the following:

- Requires the use of water, likely including a water treatment system, and disposal of wastewater
- Energy penalty due to decreased combustion turbine efficiency, but also increased power output
- May increase turbine maintenance requirements, depending on turbine type
- Can increase carbon monoxide and HC/VOC emissions[279]

Water use and water availability may be a significant environmental impact for this control technology, especially for locations in the arid West that already have water shortage issues. The 1999 DOE Report included information on expected water usage of water injection at the four turbines evaluated for the cost effectiveness analysis,[280] which can be projected into annual water use for water injection at these turbine types. The projected annual water use is provided in the table below, for both operating at a 91% capacity factor and at a 40% capacity factor. The amount of water needed for water injection is directly related to the operating capacity factor of the unit, with more water being needed for units operating at higher capacity factors.

Table 21. Projected Water Use of Water/Steam Injection at Gas-Fired Combustion Turbines[281]

Turbine Model	Size, MW	Annual Water Use at 91% Capacity Factor	Annual Water Use at 40% Capacity Factor
Solar Centaur 50	4.2	1,401,407	616,003
Allison 501-KB5	4.0	1,889,269	830,448
GE LM2500	22.7	7,093,130	3,117,859
GE MS7001F	161	95,166,555	41,831,453

[278] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[279] *See*, *e.g.*, EPA's 1993 ACT for Stationary Gas Turbines at 2-41.
[280] *See* 1999 DOE Report, Appendix A at A-5.
[281] *Id.*

As shown by the above table, water use with water/steam injection significantly increases with larger turbines and with units operated at higher capacity factors.

In addition to water availability, according to EPA, "[w]ater purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine."[282] Water quality may be more of an issue for remote sites, especially if surface water or well water is used for the water supply.[283] The costs for the water use, treatment, and disposal, as well as the energy penalty costs, were taken into account in the annual costs of controls used in the NOx cost effectiveness analyses presented in Tables 19 and 20 above.[284]

Notwithstanding the high water usage, water or steam injection is a well-proven and cost effective control for NOx emissions from gas combustion turbines of all sizes. As is discussed in Section IV.D. below, NOx limits reflective of water or steam injection have been required by EPA and numerous state and local air agencies, and water or steam injection is used to control NOx at combustion turbines extensively throughout the U.S. However, for turbines constructed in the early 1990s or later,[285] dry low NOx combustion controls were much more commonly used at gas-fired combustion turbines than water or steam injection, due to lower costs of control, improved NOx control, and the fact that there would be no need for use and treatment of water.[286] Dry low NOx combustors are also available for retrofit for several turbine makes and models. This technology to control NOx is discussed in the next section of this report.

B. DRY LOW NOx COMBUSTION

In the late 1980s, dry low NOx burners (DLNBs) became available on larger turbines[287] and, currently, such controls are available on all new turbines. As described by EPA, "[l]ean premixed combustion . . . pre-mixes the gaseous fuel and compressed air so that there are no local zones of high temperatures, or 'hot spots,' where high levels of NOx would form. Lean premixed combustion requires specially designed mixing chambers and mixture inlet zones to avoid flashback of the flame."[288] Many DLNBs can achieve reduced NOx rates across the full load range of a gas turbine.[289] DLNBs are also available to retrofit to several types of combustion turbines. General Electric has dry low NOx burner retrofit

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282 *Id.* at 7-10.
283 *Id.*
284 1999 DOE Report, Appendix A at A-5 (Table A-4).
285 Dry low NOx combustors were first developed by GE in the early 1990s. *See* CARB, Report to Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, at 19, *available at*: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.
286 *Id.* at 2-8.
287 As discussed in Chapter 7, Controlling NOx Formation in Gas Turbines, by Brian W Doyle, September 2009, at 7-1, which is part of Chapter 10 of the EPA's Air Pollution Training Institute Class APTI 418, *available at*: https://www.apti-learn.net/lms/register/display_document.aspx?dID=39.
288 EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
289 As discussed in 2012 OTC Report at 62.

options for many of its turbine makes and models, and Solar Turbines has an extensive line of retrofit kits including Solar Turbines' SoLoNOx™ technology.[290] To retrofit such DLNBs, the turbines' combustors must be replaced and there may be changes necessary to associated piping and turbine combustion controls.[291]

Based on the range of NOx emission rates that have been reported as achievable with DLNBs, these combustion controls can achieve in the range of 80% to 95% control of NOx emissions.[292] For the turbines for which DLNBs are available, NOx rates have generally ranged from 9–15 ppm.[293] The 1999 DOE Report assumed only a 25 ppmv NOx rate would be achieved at most of the combustion turbines with DLN combustion which reflects approximately 84% NOx reduction, although the DOE report also calculated costs for a larger turbine to meet a 9 ppmv NOx rate which reflects approximately 95% NOx reduction.[294] The 1999 DOE Report indicates that the operation and maintenance costs increase with the lower NOx rate being achieved.[295] The ability to achieve 9 ppmv NOx rates with dry low NOx combustors is not limited to large turbines, such as the GE Frame 7FA turbine (169.9 MW) for which the 1999 DOE Report calculated costs to achieve a 9 ppm NOx rate. Solar Turbines makes several turbines that are guaranteed to achieve 9 ppmvd NOx with Solar Turbines' SoLoNOx™ burners, including the Solar Centaur 50L which is rated at 6,276 horsepower (< 5 MW).[296] However, the ability to achieve 9 ppm NOx rates through dry low NOx combustor retrofits to existing turbines is likely more limited. Solar Turbines indicates that SoLoNOx™ retrofits are available for the Solar Taurus 70 gas turbine (11,110 horsepower).[297] GE recently announced NOx upgrades completed at 9 GE 9E Gas Turbines (132 145 MW) at a facility in China with its DLN1.0+ with Ultra Low NOx combustors to achieve about 7.5 ppm NOx rates.[298]

In its 2016 CSAPR TSD for Non-EGU NOx Emissions Controls, EPA relied on the cost analyses for DLNBs presented in the November 1999 DOE Report.[299] However, EPA acknowledged that, except for the costs for a 169 MW unit, the costs reported in the 1999 DOE Report are "incremental [costs] relative to the costs of a conventional combustor."[300] Table 22 below reflects the cost effectiveness calculations presented in the 1999 DOE report, but with changes made to the interest rate to reflect a 5.5% interest rate consistent with the EPA's Control Cost Manual and to change and life of the controls to the expected life of a combustion turbine of twenty-five years, as was done for the water/steam injection cost analyses. DLN combustors should be expected to last the life of a natural gas-fired combustion

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[290] *Id.* at 66.
[291] *Id.*
[292] *See*, e.g., 2015 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12, which indicates that 84% control can be met with DLNB achieving a NOx emission rate of 25 ppmvd.
[293] *See* 1999 DOE Report at 2-10.
[294] *Id.* at 2-10 and at Appendix A at A-3.
[295] *Id.* at 2-9 to 2-10.
[296] *See*, *e.g.*, Atlantic Coast Pipeline and Dominion Transmission, Inc., Supply Header Project, Resource Report 9, Air and Noise Quality, September 2015, at 9-24.
[297] *See* https://www.solarturbines.com/en_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html.
[298] *See* https://www.genewsroom.com/press-releases/ge-completes-worlds-first-dln10-ultra-low-nox-combustion-upgrade-nine-ge-9e-gas.
[299] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12.
[300] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12. *See also* 1999 DOE Report at 3-3 and Appendix A at A-3.

turbine, which is at least twenty-five years as discussed above. Indeed, there are likely several examples of gas turbines with dry low NOx combustor retrofits that have operated for twenty-five years. The Tennessee Gas Pipeline Company's Compressor Station in Lockport, New York has four Solar Centaur Turbines that were retrofitted with dry low NOx combustion systems in 1995[301] (two of which continue to operate today, twenty-five years later, while the other two were replaced between 2012–2019 with turbines rated at a higher horsepower).[302]

Table 22. Summary of Cost Effectiveness for DLN Combustion (1999$) at 91% Capacity Factor[303]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of DLN Combustion 1999$	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$33,491	$259/ton	
Solar Centaur 50	4.0	5,364	$14,164	$164/ton	
Solar Centaur 60	5.2	6,973	$14,164	$128/ton	
GE LM2500	22.7	30,441	$179,639	$360/ton	
GE Frame 7FA	169.9	227,839	$455,472 (25 ppmv) $474,109 (9 ppmv)	$96/ton	$92/ton

In Table 23 below, the cost effectiveness of dry low NOx combustors is calculated to reflect operation at a 40% capacity factor. Operating at a lower capacity factor should not change the operating or capital costs of the dry low NOx combustion system, given that there is no energy penalty requiring additional fuel use.

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301 NESCAUM 2000 Status Report at IV-36.

302 *See* New York State Department of Environmental Conservation (NYDEC), Permit 9-2920-00008/00015, Mod 3 Effective 12/2/2014, Issued for the Tennessee Gas Pipeline Co Compressor Station 230-C, *available at*: https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r2_3.pdf. *See also* NYDEC Title V Operating Permit 9-2920-00008/00015 issued 10/23/2018 for the Tennessee Gas Pipeline Co Compressor Station 230-C, *available at*: https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r3.pdf.

303 *See* 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a twenty-five -year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed.

Table 23. Summary of Cost Effectiveness for DLN Combustion (1999$) at 40% Annual Capacity Factor[304]

Turbine Make/Model	Size, MW	Size, hp	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$590/ton	
Solar Centaur 50	4.0	5,364	$373/ton	
Solar Centaur 60	5.2	6,973	$292/ton	
GE LM2500	22.7	30,441	$820/ton	
GE Frame 7FA	169.9	227,839	$218/ton	$208/ton

EPA's 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of DLN combustion based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, which is still high compared to today's interest rates.[305] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule for DLN combustion are reprinted below.[306]

Total Capital Investment (1999 dollars) = 2860.6 x (MMBtu/hr) + 25427

Total Annual Costs (1999 dollars) = 584.5 x (MMBtu/hr)^0.96

In its 2000 Status Report, NESCAUM provided information on the capital and operational expenses for two dry low NOx combustor upgrades to a Solar Centaur turbine (4,700 hp) and a Solar Mars turbine (13,000 hp).[307] Given that it appears the cost data in the 1999 DOE Report may not necessarily reflect retrofit costs (in that, with the exception of the costs for the GE Frame 7FA, the costs were identified in the 1999 DOE Report as "incremental" costs relative to the cost of a conventional combustor), the NESCAUM cost information for retrofit DLNC is also presented here. NESCAUM used a shorter useful life of controls than twenty-five years and a higher interest rate than the 5.5% interest rate used by EPA in its cost spreadsheets provided with its 2018 updates to the Control Cost Manual.[308] NESCAUM also assumed that DLNCs could only reduce NOx to 50 ppm, whereas such combustors should be able to reduce NOx to at least 25 ppm. Thus, in Table 24 below, the cost effectiveness of the DLNC retrofit projects discussed in the NESCAUM report are revised to reflect amortized capital costs assuming a 25-year life and a 5.5% interest rate and to reflect reducing NOx to both 50 ppm and to 25 ppm.

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[304] *See* 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a twenty-five -year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed.

[305] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11-12, Appendix B at B-2.

[306] *See id.*, Appendix A at 3-13.

[307] *See* NESCAUM 2000 Status Report at III-16.

[308] *Id.*

Table 24. Summary of Cost Effectiveness for Retrofit DLN Combustion at 40% and 91% Annual Capacity Factors Based on Retrofit Costs Provided in 2000 NESCAUM Report[309]

Turbine Make/Model	Size, hp	Capacity Factor	Cost Effectiveness of Retrofit DLN Combustion to meet 50 ppm NOx Rate	Cost Effectiveness of Retrofit DLN Combustion to Meet 25 ppm NOx Rate
Solar Centaur	4,700	91%	$1,217/ton	$940/ton
Solar Centaur	4,700	40%	$2,769/ton	$2,140/ton
Solar Mars	13,000	91%	$359/ton	$296/ton
Solar Mars	13,000	40%	$816/ton	$673/ton

The NESCAUM 2000 Status Report notes that the capital costs reported for these two turbine types were the "total project costs the owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation."[310] Thus, the costs reflected in Table 24 may be higher than what would typically be reported for DLNC controls in a cost effectiveness analysis consistent with EPA's Control Cost Manual, because EPA does not generally allow such owner's costs to be considered in a cost effectiveness analysis.[311]

In terms of non-air environmental or energy impacts with the use of DLNCs, there are relatively few impacts. There is not an energy penalty associated with the operation of the DLNCs, nor is there any waste product that requires proper disposal. However, there can be increased maintenance required with DLNCs, and those additional maintenance costs are often proprietary.[312] In fact, the increased maintenance costs are not reflected in the cost analyses for the Solar Centaur 50 and Solar Centaur 60 turbines in Tables 22 and 23 above, due to the information being considered proprietary.[313] A non-air quality environmental impact is that DLNBs "tend to create harmonics in the combustor that result in significant vibration and acoustic noise."[314]

EPA has indicated that the length of time to install DLNBs is 6–12 months.[315]

As previously discussed, while the cost estimates and cost algorithms for DLN combustion are of a cost basis that is from 1999-2000, it is important to note that, beginning in the late-1990s, EPA and numerous several state and local air agencies have found that the costs of control to achieve NOx emission limits of 25 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below.

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[309] *Id.* at III-16. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and both a 91% and a 40% operating capacity factor were assumed.
[310] *Id.*
[311] *See* EPA Control Cost Manual, Section 1, Chapter 2 at 9.
[312] *Id.* at 2-9 and 3-10.
[313] *Id.*, Appendix A at A-3.
[314] *Id.* at 2-9 and Appendix A at A-3.
[315] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 18.

Given the lower costs compared to water or steam injection, along with lower operational costs and no need to have water nearby, it is clear why DLNC has been preferable to water or steam injection since such dry low NOx combustion systems have been available. However, as stated above, these DLNC systems are not available for retrofit for all gas-fired turbines and thus, for many turbines, water or steam injection would be the available combustion control. As Tables 22 through 24 show, DLNC is more cost effective than water or steam injection and can achieve lower NOx rates. Thus, low NOx combustion is a preferable combustion-related retrofit option for gas turbines, if a low NOx combustion retrofit option is available for the turbine make and model.

C. SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion NOx reduction control that is commonly applied to gas-fired combustion turbines used for power generation. SCR technology can reduce NOx emissions by 80–90% or more and, when used along with water injection or DLNC, it can achieve NOx emission rates in the range of 1.5 to 5 ppm.[316] The 1999 DOE Report stated that SCR was the "primary post-combustion NOx control method in use" as of 1999.[317]

An SCR system consists of a reagent injection system (typically ammonia or urea) and a catalyst. The ammonia or urea (which converts to ammonia in the flue gas) is injected into the exhaust stream and the flue gas then passes over a catalyst reduced NOx to N_2, H_2O, and CO_2. The catalyst selected depends on the temperature range of the flue gas and the size of the catalyst depends on the level of NOx reduction to be achieved. SCR technology requires a reagent injection system, including a storage tank and reagent injectors and controls to regulate the quantity of reagent, and the SCR catalyst. According to the 1999 DOE Report, the cost of conventional SCR had dropped significantly by 1999 with innovations in catalysts allowing for a significant reduction in catalyst volume with no change in NOx removal performance.[318] Catalysts are also available for SCR to work at a variety of flue gas temperatures, from as low as 300 degrees Fahrenheit to as high as 1,100 degrees Fahrenheit.[319] For simple cycle turbines, which are more commonly used in the oil and gas sector, the reactor chamber with the catalyst is in place directly at the turbine exhaust, which may require the use of high temperature catalyst such as zeolite.[320] Several options for SCR catalyst exist for simple cycle turbines. For example, BASF makes several SCR catalysts that it claims can achieve up to 97% NOx reduction.[321] The NOxCat ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications.[322] The NOxCat VNX and ZNX catalysts can achieve up to 99%

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[316] *See*, *e.g.*, EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18; 2012 OTC Report at 63.
[317] 1999 DOE Report at 1-5.
[318] *Id.*
[319] *Id.*
[320] *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf page 36.
[321] *See* BASF, SCR Catalysts for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/scr-cat-pow-gen.
[322] *See* BASF, NOxCat ETZ, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nOx-Cat-_ETZ.

NOx reduction and are most effective at a temperature range of 550 to 800 degrees Fahrenheit.[323] A related catalyst called NOxCat VNX-HT is designed for use in aeroderivative simple-cycle turbines that can achieve 99% NOx removal and can reach optimal performance at 800 to 850 degrees Fahrenheit.[324]

Conventional SCR systems can be used with simple cycle turbines if the gas stream is cooled to the optimal temperatures for conventional SCR catalysts, through air dilution or tempering.[325] Further, aeroderivative turbines typically have somewhat lower exhaust gas temperatures which can work better with conventional SCR systems than frame-type turbines.[326] The optimal temperature of the flue gas to both minimize the amount of catalyst needed and ensure the highest NOx removal (> 90%) is 700 to 750 degrees Fahrenheit for conventional SCR catalysts.[327] Conventional catalysts can achieve 80% or greater NOx removal over a wide temperature range of approximately 625 to 900 degrees Fahrenheit.[328] SCR vendors have experience installing SCR to achieve low NOx emission rates on numerous simple cycle turbines of all types and sizes.[329]

In its Control Cost Manual chapter on SCR, which was updated in 2019, EPA cites capital costs of SCR for simple cycle gas turbines that range from $237/kilowatt for a 2 MW gas turbine down to $50/kilowatt for a larger gas turbine, all in 1999 dollars cost basis.[330] For these cost ranges, EPA cites to the NESCAUM 2000 Status Report.[331] That NESCAUM report in turn relies on the 1999 DOE Report, as well as a 1991 report by the Electric Power Research Institute and some personal communications.[332] The NESCAUM 2000 Status report provides a range of cost effectiveness data based on these reports for the application of high temperature SCR to gas turbines of varying operating capacity factors, sizes, and baseline NOx emission rates. Table 25 below presents that data for turbines with year-round high temperature SCR operation.

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323 *See* BASF, NOxCat VNX & ZNX for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nox-cat-VNX-ZNX-pow-gen.

324 *Id.*

325 *See, e.g.*, Buzanowki, M. and S. McMenamin, Automated Exhaust Temperature Control for Simple-Cycle Power Plants, 2/11/2011, Power Magazine, *available at*: https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/?printmode=1.

326 Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc., at iv, *available at*: http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frame-type_combustion_turbines.pdf.

327 *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf pages 20-21.

328 *Id.* at pdf page 20.

329 *See*, *e.g.*, McGinty, Bob, Mitsubishi Hitachi Power Systems, Gas Turbine & Industrial SCR Systems, Lessons Learned Firing NG and ULSD in Large Frame Simple Cycle Gas Turbine Hot SCR Systems, *available at*: http://cemteks.com/cemtekswp/wp-content/uploads/2016/12/lessons_learned_firing_ng_and_ulsd_in_large_frame_simple_cycle_gas_turbine_hot_scr_systems.pdf; Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc.

330 US EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction (June 2019) at pdf page 12.

331 *Id.* at pdf page 98 (see Reference 19).

332 NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15).

Table 25. Cost Effectiveness for High Temperature SCR Retrofit on Simple Cycle Gas Turbines.[333]

Turbine Size, MW	Turbine Size, hp	Uncontrolled NOx, ppm	Controlled NOx, ppm	Cost Effectiveness of SCR, $/ton (2000$), at listed capacity factor	Capacity Factor
75	100,590	154	15	$849	45%
75	100,590	154	15	$664	65%
75	100,590	154	15	$566	85%
75	100,590	42	7	$2,980	45%
75	100,590	42	7	$2,247	65%
75	100,590	42	7	$1,859	85%
75	100,590	15	3	$8,441	45%
75	100,590	15	3	$6,303	65%
75	100,590	15	3	$5,171	85%
5	7,000	142	15	$3,395	45%
5	7,000	142	15	$2,523	65%
5	7,000	142	15	$2,061	85%
5	7,000	42	5	$11,335	45%
5	7,000	42	5	$8,341	65%
5	7,000	42	5	$6,756	85%

The different shading in the table reflects different levels of NOx combustion controls of the existing turbine:

- Gray shading reflects the cost effectiveness of SCR applied to gas turbines with no water injection or dry low NOx combustion controls, in which case the SCR was assumed to achieve about 90% NOx reductions.
- Blue shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, water injection which can achieve 42 ppm or lower NOx emission rates, in which case the SCR was assumed to achieve about 83–88% removal.
- Green shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, low NOx combustion controls that can achieve 15 ppm NOx, in which case the SCR was assumed to achieve 80% removal.

[333] *Id.* at III-24.

The NESCAUM cost effectiveness numbers in Table 25 above reflect a 15-year equipment life and an interest rate of 7.5%.[334] The NESCAUM cost effectiveness numbers were also primarily based on the 1999 DOE report.[335] However, EPA has indicated that a 25-year life is a more appropriate life of an SCR system at a gas turbine used in an industrial setting like a compressor station.[336] Further, as stated above, EPA currently uses a 5.5% interest rate in its cost effectiveness calculations. Tables 26 and 27 below present the cost effectiveness for conventional and high-temperature SCR added to a gas-fired combustion turbine meeting an uncontrolled rate of 42 ppmv, reflective of water or steam injection, to achieve a controlled NOx rate of 9 ppmv, which reflects a 79% reduction in NOx emissions. These cost effectiveness analyses are based on the costs of the 1999 DOE Report, but with the capital cost amortized to reflect a 25-year equipment life and a 5.5% interest rate.[337] The 1999 DOE cost analyses were based on operating 8,000 hours per year, or a 91% capacity factor. Given information previously cited that, on average, a compressor unit may operate at a 40% annual capacity factor,[338] revisions to the cost data and emissions reduced were made to reflect a 40% capacity factor. Specifically, the electricity costs (due to the parasitic load of the SCR system) and the ammonia costs in the direct annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in SCR operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor.[339]

[334] *Id.* at IV-22.
[335] *Id.* at III-21 through III-24 (see cites to Reference 11, which is the 1999 DOE report).
[336] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.
[337] 1999 DOE Report at 3-9 to 3-10, Appendix A at A-6 to A-7.
[338] 2012 OTC Report at 16.
[339] It is possible that other items in the direct annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.

Table 26. Cost Effectiveness to Reduce NOx Emissions by Conventional SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor[340]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of Conventional SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Centaur 50	4.2	5,632	42	9	$135,475	$11,794/ton	40%
Solar Centaur 50	4.2	5,632	42	9	$143,368	$5,486/ton	91%
GE LM2500	22.7	30,441	42	9	$295,872	$6,098/ton	40%
GE LM2500	22.7	30,441	42	9	$317,134	$3,049/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,426,883	$3,050/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,317,285	$1,679/ton	91%

340 1999 DOE Report, Appendix A at A-6 (Table A-5). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). To reflect a 40% capacity factor, the annual operating costs due to the fuel penalty and ammonia use were decreased by 56%, to reflect a 40% capacity factor rather than a 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

Table 27. Cost Effectiveness to Reduce NOx Emissions by High Temperature SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor[341]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of High Temperature SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Taurus 60	5.2	6,973	42	9	$179,385	$13,238/ton	40%
Solar Taurus 60	5.2	6,973	42	9	$188,760	$6,123/ton	91%
GE LM2500	22.7	30,441	42	9	$324,122	$6,680/ton	40%
GE LM2500	22.7	30,441	42	9	$364,879	$3,305/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,379,722	$3,695/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,680,250	$1,978/ton	91%

Although the above costs reflect a 1999-2000 dollar cost basis, EPA has indicated that the costs of conventional SCR "have dropped significantly over time – catalyst innovations have been a principal driver, resulting in a 20% in catalyst volume and cost with no change in performance."[342] Moreover, high temperature SCR catalysts are not necessarily required for turbines operated in simple cycle mode, as was assumed in the NESCAUM 2000 report, because air tempering can be used to lower the cost of the exhaust gas stream, as discussed above. Thus, it is likely that costs for SCR at gas-fired turbines are lower than the cost estimates in the 1999 DOE report and the NESCAUM 2000 Status Report. Indeed, in 2015, the SCAQMD in California collected SCR cost information from vendors for 20 non-refinery, non-power plant gas turbines including turbines used in gas compression, and total installed costs ranged

[341] 1999 DOE Report, Appendix A at A-7 (Table A-6). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). The annual costs due to the fuel penalty and ammonia use were decreased by 56% to reflect a 40% capacity factor, rather than the 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

[342] *See* EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

from $1.5 million to $2.9 million with the annual costs ranging from $63,000 to $727,000.[343] These costs reflected SCR achieving 95% control for those turbines with NOx rates of 40 ppm or higher and achieving 2 ppm for those turbines with NOx rates lower than 40 ppm.[344] The cost basis of these costs is not identified, but presumably the costs are from the 2010-2015 timeframe.[345] In 2019, SCAQMD ultimately determined it was cost effective to require SCR retrofits as BARCT for non-refinery, non-power plant combustion turbines. SCAQMD required gas turbines of capacities 0.3 MW and larger that power compressor stations to install retrofit NOx controls to meet a NOx limit of 3.5 ppmv at 15% oxygen and required other gas turbines, such as those used for power generation, to meet a NOx limit of 2.5 ppmv.[346] These limits are required to be met by 2024.[347] Other California air districts have adopted NOx limits for existing simple cycle gas turbines that reflect installation of SCR with NOx limits ranging from 2.5 to 9 ppm.[348] While several of these air districts limits were based on SCR applied to turbines of 10 MW capacity or greater, the SJVAPCD in California adopted NOx limits in the range of 5 to 9 ppmv for gas turbines in 2007 that were based on the installation of SCR, with the higher limits for turbines with capacities between 0.3 MW and 10 MW.[349]

The use of SCR presents several non-air quality and energy impacts, most of which are accounted for in the annual operating costs. Those impacts include the following:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) to maintain the same steam output at the boiler.[350]
- The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered hazardous waste.[351] The use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed of.[352]

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343 SCAQMD, Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM, July 21, 2015, at 183, *available at*: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/pdsr-072115.pdf?sfvrsn=2.

344 *Id.* at 182.

345 It is assumed the cost data were collected before 2014. *See* November 26, 2014 report entitled "NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR," available on SCAQMD's website at https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaimbarct-nonconf-nonrefinery_112614.pdf?sfvrsn=2.

346 *See* Rule 1134(d)(4), Table II, *available at*: http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.

347 *Id.*

348 These other California air districts that adopted NOx limits for gas-fired combustion turbines in the 2.5 to 9 ppm range include Sacramento AQMD, Bay Area AQMD, San Joaquin AQMD, Ventura County AQMD, and Yolo Solano AQMD. Further, it must be noted that while a 9 ppmv NOx limit can be met with ultra-low NOx combustors at some turbines, SCR may be required at other units to meet such a NOx limit.

349 *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, *available at*: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf.

350 EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.

351 *Id.* at pdf 18.

352 *Id.* at pdf 18-19.

- If anhydrous ammonia is used, there would be an increased need for risk management and implementation and associated costs for receiving and storing the anhydrous ammonia.[353] If urea or aqueous ammonia is used as the reagent, the hazards from use of pressurized anhydrous ammonia do not apply.
- Excess ammonia can pass through the SCR (called "ammonia slip"), which then can react with sulfate or nitrate in the ambient air to form ammonium bisulfate or ammonium nitrate (i.e., fine particulate matter).[354] Typically, permitting authorities limit the amount of ammonia slip that may occur with SCR to limit the formation of ammonium bisulfate or ammonium nitrate.

There are typically not overarching non-air quality or energy concerns with this technology, and SCR technology is widely used at natural gas-fired combustion turbines. Most of the impacts mentioned above are considered as additional costs of using SCR and are taken into account in the SCR cost effectiveness analysis.

In terms of length of time to install SCR at gas-fired combustion turbines, a report prepared for the SCAQMD found that the typical installation time is about twenty-four months after an engineering firm begins the engineering design for the SCR, or a total of about 27–30 months.[355] These costs should all be included in the annual operating costs.

There are numerous examples of natural gas-fired combustion turbines with SCR installed for NOx control. Just in the electric utility industry, there are at least 310 gas-fired combustion turbines operating with SCR.[356] Clearly, SCR has been considered to be a cost effective NOx reduction technology for combustion turbines, including smaller compressor engines and those that power compressor stations, since at least 2007. Further, SCR is often combined with a combustion control like water injection or dry low NOx combustors, which optimizes the NOx emissions reductions and costs of control.

D. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

In 2005, EPA proposed a new NSPS for gas turbines, which was eventually promulgated at 40 C.F.R. Part 60, Subpart KKKK in 2006.[357] In promulgating Subpart KKKK, EPA updated the NSPS for gas turbines, which had last been reviewed for EPA's initial promulgation of NSPS for gas turbines in 1979.[358] As a starting point for considering the level of control that EPA considered to be cost effective as a retrofit control for existing gas turbines, it is instructive to review what EPA required in the NSPS Subpart KKKK

[353] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[354] *See* 1999 DOE Report at 2-11.
[355] *See* ETS, Inc., NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR, FINAL REPORT, NOVEMBER 26, 2014, at 17.
[356] Based on a search on EPA's Air Markets Program Database, *available at*: https://ampd.epa.gov/ampd/.
[357] 70 Fed. Reg. 8,314-8,332 (Feb. 18, 2005), 71 Fed. Reg. 38,482-38,506 (July 6, 2006).
[358] 44 Fed. Reg. 52,798.

for existing gas turbines that were modified on or after February 18, 2005. These standards are summarized in the table below. It is important to note that these standards were adopted for gas turbines that generate electricity or that are used for mechanical drive such as at a gas compressor station.

Table 28. NSPS Subpart KKKK NOx Control Requirements for Modifications to Existing Gas Turbines Occurring on or after February 18, 2005.[359]

Turbine Size/Range	Approximate Turbine size range, hp[360]	Subpart KKKK NOx limits for modified sources after 2/2005, ppmv	Control that NOx limit reflects
≤50 MMBtu/hr	≤6,850 hp	150	Probably none
>50 MMBtu/hr and ≤850 MMBtu/hr	>6,850 hp and ≤116,456 hp	42	Water/Steam Injection
>850 MMBtu/hr	>116,456 hp	15	DLNC

Thus, in 2005, EPA found that the cost of water or steam injection or dry low NOx combustion was cost effective for gas-fired turbines with capacity greater than 50 MMBtu/hr (or 116,500 hp, ~86 MW). In considering reasonable progress controls for gas-fired combustion turbines in the oil and gas industry in 2020, the EPA's NSPS NOx limits for sources modified in 2005 or later should be considered the "floor" of potential NOx controls to consider for an existing gas turbine meaning that, at the very minimum, this level of control should be considered cost effective for NOx reductions at gas turbines. However, installation of SCR, with or without water/steam injection or DLNC, would be the much more effective pollution control that should be evaluated in an analysis of controls to achieve reasonable progress, as it has been found to be a cost effective control for gas-fired combustion turbines.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing gas turbines to meet, many of which have been in place for 10–20 years. In Table 29 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA's 2016 CSAPR TSD,[361] which provided a summary of state NOx regulations for gas turbines and other NOx sources as of September 2014.[362] The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. EPA found that 9 CSAPR states did not have regulations limiting NOx emissions from existing gas turbines: Alabama, Arkansas, Indiana, Kentucky, Michigan, Mississippi, Oklahoma, South Carolina, and West Virginia.[363] We also reviewed California Air District rules, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas turbines. Indeed, several air districts in California have adopted rules necessitating installation of SCR at

[359] *See* 40 C.F.R. Part 60m Subpart KKKK, Appendix, Table 1.
[360] Converted MMBtu/hr to hp based on following assumptions/conversion factors: Typical heat rate of simple cycle turbine of 9,788 Btu/kWh (per https://www.eia.gov/todayinenergy/detail.php?id=32572), and 0.7457 kW= 1 hp.
[361] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 11-13.
[362] *Id.*
[363] *Id*. at 13.

virtually all simple cycle turbines. We reviewed some of the remaining states' regulations to determine whether there were NOx limitations for existing gas turbines. Specifically, we reviewed air regulations in New Mexico, Colorado, Utah, Montana, North Dakota, South Dakota, and Washington. It appears there are no NOx emission limits required for existing gas turbines in those states aside from what applies to modified gas turbines under the NSPS Subpart KKKK.

Table 29 is a summary of the NOx emission limits required of existing simple cycle gas-fired combustion turbines in state and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing gas turbines. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart KKKK, gas turbines did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing gas turbines and generally require an air pollution control retrofit or an outright replacement of the gas turbine with a new turbine with integrated dry low NOx combustors. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the $PM_{2.5}$ NAAQS. Nonetheless, what becomes clear in this analysis is that numerous states and local governments have adopted NOx regulations that require, at the very least, water or steam injection at existing gas turbines (or DLNC if available) to meet NOx limits of 42 ppmv,[364] and several state/local air agencies have adopted NOx limits in the range of 9–25 ppmv which require dry low NOx combustors or, if unavailable as a retrofit for the turbine type, SCR. Moreover, four California air districts and Georgia have adopted NOx limits for gas turbines that clearly require SCR, probably along with water injection or DLNC, to comply with NOx limits in the range of 2–5 ppmv. The lowest NOx limits are those recently adopted by the SCAQMD which require, by January 1, 2024, gas-fired combustion turbines of 0.3 MW or greater size to meet a 2.5 ppmv limit and compressor gas turbines to meet a 3.5 ppmv limit.

These limits were adopted generally to meet RACT and California BARCT requirements, and costs of controls are considered in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls."[365] BARCT, on the other hand, is defined as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."[366] BARCT is similar to a BACT determination under the federal PSD program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

[364] Even some of the NOx limits in Table 29 that are higher than 42 ppmv may require water or steam injection to meet the limit.
[365] 40 C.F.R. § 51.100(o).
[366] HSC Code § 40406 (California Code), *available at:* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.

Table 29. Summary of State/Local Air Agency NOx Emission Limits for Existing Simple Cycle Gas-fired Combustion Turbines that Require NOx Pollution Controls[367]

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Sacramento Metro AQMD[368]	Rule 413.301.3	>0.3 MW or 3 MMBtu/hr (RACT)	42
	Rule 413.302.1	<2.9MW or >2.9 MW but <877 hrs/yr (BARCT[369])	42
		>877 hrs/yr & 2.9-10 MW (BARCT)	25
		>877 hrs/yr or >10 MW without SCR (BARCT)	15
		>877 hrs/yr or >10 MW with SCR (BARCT)	9
CA – Bay Area AQMD[370]	Regulation 9-9-301 Effective 1/1/2010:	5-50 MMBtu	42 ppmv or 2.12 lb/MWhr
		>50-150 MMBtu/hr & no retrofit available	42 ppmv or 1.97 lb/MWhr
		>5-150 MMBtu/hr & Water/Steam Injection Enhancement available	35 ppmv or 1.64 lb/MWhr
		>50 150 MMBtu/hr & DLNC available	25 ppmv or 1.17 lb/MWhr
		>150- 250 MMBtu/hr	15 ppmv or 0.70 lb/MWhr
		>250-500 MMBtu/hr	9 ppmv or 0.43 lb/MWhr
		>500 MMBtu/hr	5 ppmv or 0.15 lb/MWhr
		<877 hrs/yr & 50-250 MMBtu/hr	25 ppmv or 1.97 lb/MWhr
		250-500+ MMBtu/yr	25 ppmv or 1.17-0.72 lb/MWhr

[367] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.
[368] http://www.airquality.org/ProgramCoordination/Documents/rule413.pdf.
[369] Best Available Retrofit Control Technology (BARCT) was to be met by May 31, 1997.
[370] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-9-nitrogen-oxides-and-carbon-monoxide-from-stationary-gas-turbines/documents/rg0909.pdf?la=en.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA-SCAQMD[371]	Rule 1134	>0.3-2.9 MW	25 (reference limit) x EFF/25%[372]
	Effective 12/31/95:	2.9-10.0 MW	9 (reference limit) x EFF/25%
		2.9-10.0 MW (no SCR)	15 (reference limit) x EFF/25%
		>10.0 MW	9 (reference limit) x EFF/25%
		>10.0 MW and no SCR	12 (reference limit) x EFF/25%
	By 1/1/24:	>0.3 MW	2.5
		Compressor gas turbine	3.5
CA – SJVAPCD[373]	Rule 4703 Tier 3 limits[374]	>0.3 MW to <3 MW	9
		3-10 MW pipeline gas turbine	8 (steady state) and 12 (non-steady state)
		>3-10 MW & <877 hrs/yr	9
		>10 MW & <200 hr/yr	25
		3-10 MW & >877 hrs/yr and >10 MW and 200-877 hrs/yr	5
		>10 MMW	3-5[375]
	Rule 74.23	0.3-2.9 MW	42

[371] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.
[372] EFF = gas turbine efficiency, which can never be less than 25%. In other words, this multiplier allows a higher ppm limit than the reference limit if a turbine is more efficient than 25%.
[373] https://www.valleyair.org/rules/currntrules/r4703.pdf.
[374] Note that NOx limits reflective of water/steam injection, DLNC, and/or SCR have been in effect in San Joaquin Valley since 2000. Compliance with the Tier 3 limits was required between 2009-2012.
[375] Tier 2 limits, that were to be complied with in 2005, require turbines greater than 10 MW and greater than 877 hours per year to meet NOx limits in the range of 3-5 ppmv. *See* Table 5-2 of San Joaquin AQMD Rule 4703. Tier 3 limit is 5 ppmv for turbines>10 MW but with operations between 200 hr/yr - 877 hrs/yr. *See* Table 5-3 of San Joaquin AQMD Rule 4703.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Ventura County APCD[376]		2.9-10.0 MW	25 x EFF/25
		>10.0 MW w/SCR	9 x EFF/24
		>10 MW w/o SCR	15 x EFF/25
		>4.0 MW & <877 hrs/yr	42
	<u>Currently proposed revisions:</u> By 1/1/24:	All turbines	2.5
CA – San Diego APCD[377]	Rule 69.3.1	≥1.0 & <2.9 MW	42
		≥2.9 & <10.0 MW	25 x EFF/25
		≥10.0 MW w/o installed post combustion air pollution controls	15 x EFF/25
		≥10.0 with installed post-combustion air pollution controls	9 x EFF/25
CA-Yolo Solano AQMD[378]	Rule 2.34	0.3-2.9 MW & >877 hrs/yr AND >4 MW & less than 877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA-Imperial County APCD[379]	Rule 400.1	>1 MW & >400 hr/yr	42
CA-Mojave Desert AQMD[380]	Rule 1159	>4MW & >877 hrs/yr	42
CA – Placer County APCD[381]	Rule 250	>0.3-2.9 MW&>877 hrs/yr	42

[376] http://vcapcd.org/Rulebook/Reg4/RULE%2074.23.pdf.
[377] https://ww3.arb.ca.gov/drdb/sd/curhtml/r69-3-1.pdf.
[378] https://ww3.arb.ca.gov/drdb/ys/curhtml/r2-34.pdf.
[379] https://ww3.arb.ca.gov/drdb/imp/curhtml/r400-1.pdf.
[380] https://ww3.arb.ca.gov/drdb/moj/curhtml/r1159.htm.
[381] https://ww3.arb.ca.gov/drdb/pla/curhtml/r250.pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		>4 MW & <877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA – Tehama County APCD	Rule 4: 37	>0.3 MW (exempt if <4 MW&<877 hrs/yr)	42
TX/Houston Galveston Brazoria Ozone NAA[382]	30 TAC 117.310(a)(11)	Emission specs for mass emission cap and trade >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.305(c)	Turbines >10.0 MW	42
	30 TAC 117.2010(c)(5)	1.0< &>10.0 MW	0.15 lb/MMBtu
TX/Dallas[383]	30 TAC 117.410(a)(5)	Emission Specs for 8 hr ozone Demo >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.405(b)(3)	RACT >10,000 hp	0.15 lb/MMBtu
TX/Beaumont Port Arthur[384]	30 TAC 117.105 (c)	RACT>10.0 MW	42
GA (45 county area – ozone)	Rule 391-3-1-.02.(2)(nnn)1.(i) This appears to be an existing source requirement, with compliance required by 5/1/03	>25 MW, permitted <4/1/00	30
	Rule 391-3-1-.02.(2)(nnn)1.(iii)	>25 MW, permitted after 4/1/00[385]	6
WI (Milwaukee 7 county area)[386]	NR 428.22(1)(g)	>50 MW	25

[382] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=3&rl=Y.
[383] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=4&rl=Y.
[384] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=105.
[385] This appears to be a new source requirement because compliance was required upon startup.
[386] https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/IV/22.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		25-50 MW	42
NJ[387]	7:27-19.5(d)	>25 MMBtu/hr (case by case exemptions allowed for limits on water supply or no commercially available DLNCs)	2.2 lb/MWhr
	7:27-19.5(g)1 (Table 7)	HEDD Simple Cycle Gas Turbine (Power Generators) >15 MW	1.00 lb/MWhr
DE[388]	Title 7, §1112.3.5 (Table 3-2)	Gas turbines >15 MMBtu/hr	42
IL (Chicago are and Metro East area)[389]	Title 35 Part 217, §217.388a.1.E.	Gas turbines >2.5 MW (4,694 bhp)	42
PA[390]	Ch. 129.97(g)(2)(iv)	Gas turbines > 6,000bhp	42
MD (certain counties)[391]	COMAR 26.11.09.08G(2)	Turbines with Capacity Factor >15%	42
VA (northern VA)[392]	9VAC5-40-7430 (9VAC5-40-7410 requires compliance with RACT)	Turbines >10 MMBtu/hr RACT Limit	42
OH (Cleveland 8 county area)[393]	3745-110-03(E)(1)	>3.5 MW	42
CT[394]	22a-174-22e	Simple Cycle combustion turbines>5 MMBtu/hr	55

387 https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.
388 http://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml#TopOfPage.
389 http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.
390 http://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/s129.97.html&searchunitkeywords=129.97&origQuery=129.97&operator=OR&title=null.
391 http://mdrules.elaws.us/comar/26.11.09.08.
392 https://law.lis.virginia.gov/admincode/title9/agency5/chapter40/section7430/.
393 https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-03_Final.pdf.
394 https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		Phase I limits (2018-2023) Ozone Season	50
MA[395]	310 CMR 7.19:(7)(a)1	>25 MMBtu/hr	65
NY[396]	6CRR-NY 227-2-4(e)	>10 MMBtu/hr	50
	6CRR-NY 227-3.4(a)(2) New Rule – compliance by 5/1/25[397]	>15 MW	25
LA (Baton Rouge 5 Counties & Region of Influence)[398]	LAC 33.03, Chapter 22, §2201.D.1 (Table D-1A)[399]	≥5-10 MW	0.24 lb/MMBtu (65 ppmv)
		≥10 <MW	0.16 lb/MMBtu (43 ppmv)
MO (St Louis Area)[400]	10 CSR 10-5.510(3)(C)1	>10 MMBtu/hr	75
NC (Charlotte 6 County Area)[401]	15A NCAC 02D.1408	>100 and ≤ 250 MMBtu/hr	75

As the above table shows, eleven state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired simple cycle combustion turbines that reflect operation of SCR or possibly dry low NOx combustors (i.e., NOx emission limits in the range of 2.5 to 9 ppmv). SJVAPCD's NOx limits for pipeline gas compressor stations of 8 ppm (steady state) and 12 ppmv (non-steady state),

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395 https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
396 https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
397 https://www.dec.ny.gov/regulations/116185.html.
398 https://www.deq.louisiana.gov/resources/category/regulations-lac-title-33.
399 These are emission factors, used in setting facility emission caps.
400 https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf.
401 https://files.nc.gov/ncdeq/Air%20Quality/rules/rules/D1408.pdf.

which were adopted in 2007, also reflect application of SCR.[402] The state of Georgia has stringent NOx limits for larger turbines in its 45-county ozone nonattainment area that also likely require SCR to comply with the NOx emission limits. These air agencies have thus found that the levels of NOx control listed in Table 29, including NOx limits as low as the 2.5–5 ppmv range of NOx emissions, are cost effective for existing simple cycle natural gas-fired combustion turbines.

NOx Limits Required for New Gas Turbines Used in the Oil and Gas Sector

Recently, there have been some examples of SCR being required in draft or final air construction permits for proposed new installations of compressor stations powered by gas-fired combustion turbines. Specifically, SCR was proposed to meet BACT requirements for the proposed Buckingham Compressor Station to be located in Virginia, with all four combustion turbines ranging from 6,276 to 15,900 hp to be subject to a NOx BACT emission limit of 3.75 ppmv at 15% oxygen.[403] In addition, SCR was proposed to be installed at the Charles Compressor Station to be located in Maryland,[404] the Northampton Compressor Station to be located in North Carolina,[405] and the Marts Compressor Station to be located in West Virginia.[406] These draft and final permits provide additional evidence of states and companies finding SCR to not be a cost prohibitive control for a compressor station.

E. SUMMARY – NOx CONTROLS FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

The above analyses and state/local rule data demonstrates that numerous state and local air agencies have found water/steam injection, dry low NOx combustors, and SCR as cost effective controls for natural gas-fired combustion turbines, with costs ranging from $128/ton to $13,500/ton (1999$) to

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[402] *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, *available at*: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf. The fact that these limits require SCR to meet is reflected in permits for two compressor stations – the Wheeler Ridge Compressor Station and the Kettleman Compressor Station. *See* March 25, 2015 Title V Permit for Southern California Gas Co. Wheeler Ridge Compressor Station, *available at*: https://www.valleyair.org/notices/Docs/2015/03-25-15_(S-1134792)/S-1134792.pdf; February 5, 2018 Title V Permit for Pacific Gas and Electric Company – Kettleman Compressor Station, *available at*: http://www.valleyair.org/notices/Docs/2018/2-5-18_(C-1161601)/C-1161601.pdf.

[403] *See* January 9, 2019 Registration No. 21599, *available at*: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.

[404] *See* Draft Permit for Dominion Energy Cove Point – Charles Station, *available at*: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf. It is not clear whether the final air permit has been issued yet for this facility.

[405] *See* Air Permit No. 10466R00, issued February 27, 2018, *available at*: https://edocs.deq.nc.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Permit%20Northampton%20Compressor%20Station.pdf.

[406] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf.

meet NOx limits ranging from 42 ppmv down to 2.5 ppmv. Further, it is notable that, in the rules summarized above in Table 29, the primary exemptions or higher allowable NOx limits for low use turbines are those that operate at 10% or lower annual capacity factors (i.e., less than 877 hours/year), although there are several California districts with no exemptions for low capacity factor turbines. In addition, although there are some states that limited applicability of NOx emission limits to larger turbines (e.g., greater than 10 MW (or greater 13,500 hp or 100 MMBtu/hour)), there are several states and local air pollution control agencies that set NOx limits requiring NOx controls for turbines smaller than 10 MW. In fact, several California districts set a NOx limit reflective of water or steam injection (i.e., 42 ppmv) for turbines as small as 0.3 MW.

As states evaluate the level of NOx control to require at gas-fired combustion turbines associated with the oil and gas industry to make reasonable progress towards the national visibility goal, costs of NOx control should not be a significant consideration in the decision of what NOx emission limits to require existing natural gas-fired combustion turbines to meet, as there are ample examples of existing gas-fired combustion turbines being required to incur similar costs of control. Indeed, SCR should be considered the control technology of choice for NOx removal at gas-fired combustion turbines of 0.3 MW size or larger, including those that operate compressor stations and/or that operate at lower capacity factors. Combustion turbines with SCR should be able to meet NOx limits in the range of 2.5 to 9 ppmv NOx. For those turbines for which SCR is not technically or economically feasible, DLNCs should be the next control technology with NOx emission limits achievable in the 7.5 to 25 ppm range. If DLNCs are not available for retrofit to the turbine model, water or steam injection should be considered for NOx control, which should enable the combustion turbine to meet NOx limits in the range of 25 to 42 ppmv. It also must be recognized that, in some cases, it may be more effective for NOx control — and more cost effective — to require replacement of existing gas-fired turbines with new turbines designed with state-of-the-art dry low NOx combustion controls, as such controls can achieve much lower NOx rates than water or steam injection and do not require water usage.

V. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

VOC emissions from natural gas-fired combustion turbines result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates.

Similar to RICE units, NOx is emitted at much higher rates from uncontrolled natural gas-fired combustion turbines compared to VOC emissions, with uncontrolled VOC emissions about two orders of magnitude lower than NOx emissions according to EPA's AP-42 emission factor documentation.[407] On the basis of pounds of VOC emission per heat input, EPA's AP-42 emission factors indicate that natural

[407] EPA, AP-42, Section 3.1, Tables 3.1-1 and 3.1-2, *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

gas-fired combustion turbines emit VOCs at a much lower rate that natural gas-fired RICE.[408] However, it must be noted that EPA's uncontrolled VOC emission factor has an emission factor rating of "D," which means tests are based on a generally unaccepted method and/or from a small number of facilities.[409] Regardless, the same control for VOC emissions from lean-burn RICE units – oxidation catalyst – applies to control of VOC emissions from natural gas-fired combustion turbines.

According to EPA, oxidation catalyst is typically used on combustion turbines to control CO emissions as well as HAP emissions – primarily formaldehyde.[410] Removal of VOCs is a co-benefit of oxidation catalyst at natural gas-fired combustion turbines. Data collected by CARB of emission test results at combustion turbines used for power generation that were equipped with oxidation catalysts, among other air pollution controls, showed VOC emission rates generally in the range of 1 to 3 ppmv at 15% oxygen.[411]

It is not clear that oxidation catalyst has been widely implemented at existing natural gas-fired combustion turbines. According to documentation for EPA's 2019 Risk and Technology Review for its Stationary Combustion Turbine NESHAP, a review of air permits for 719 turbines found 50 units using oxidation catalyst.[412] That said, the data collected by CARB in 2004 indicated 31 natural gas-fired combustion turbines using oxidation catalyst.[413]

In addition, oxidation catalyst has been recently proposed and required for new natural gas-fired combustion turbines used in the oil and gas industry. For example, in its permit application for the Weymouth Compressor Station to be located in Massachusetts, oxidation catalyst was proposed to be installed on a combustion turbine-driven compressor unit to reduce VOCs as well as to reduce CO and HAP to meet BACT. Oxidation catalyst has been proposed to be installed along with SCR at the proposed Buckingham Compressor Station to be located in Virginia,[414] the Charles Compressor Station to be located in Maryland,[415] the Northampton Compressor Station to be located in North Carolina,[416] and the

[408] Compare VOC emission factors from EPA's AP-42, Section 3.1, Tables 3.1-1 and 3.1-2 to EPA's AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3.
[409] EPA AP-42, Introduction at 8-10.
[410] EPA, AP-42, Section 3.1, at 3.1-7.
[411] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A, *available at*: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.
[412] *See* December 11, 2018 Memo from RTI International to Melanie King, EPA, at 3, in EPA's docket for its Risk and Technology Review for the Stationary Gas Turbine NESHAP, Docket ID EPA-HQ-OAR-2017-0688-0066, *available at*: www.regulations.gov.
[413] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A.
[414] *See* January 9, 2019 Registration No. 21599, *available at*: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.
[415] *See* Draft Permit for Dominion Energy Cove Point – Charles Station, *available at*: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf. It is not clear whether the final air permit has been issued yet for this facility.
[416] *See* Air Permit No. 10466R00, issued February 27, 2018, *available at*: https://edocs.deq.nc.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Permit%20Northampton%20Compressor%20Station.pdf.

Marts Compressor Station to be located in West Virginia.[417] These draft and final permits provide evidence of states and companies finding oxidation catalyst to be a cost effective control for a combustion turbine-powered compressor stations.

In summary, oxidation catalyst is an available air pollution control to reduce VOC emissions, as well as to reduce CO and HAP emissions, from natural gas-fired combustion turbines used in the oil and gas industry. States should consider oxidation catalyst when evaluating reasonable progress controls for natural gas-fired combustion turbines used in the oil and gas industry.

VI. CONTROL OF EMISSIONS FROM DIESEL-FIRED RICE

Compression-ignited (*i.e.*, diesel-fired) RICE units are used in oil and gas exploration, production, and transmission sectors. These types of engines are generally used in the oil and gas industry for on-site power generation, as well as to power or to drive drill rigs, drive hydraulic fracturing pumps, and to power other pumping and compression applications. According to EPA's Alternative Control Techniques Document for Stationary Diesel Engines (2010), many of the "stationary" diesel RICE (meaning engines that are not mobile) are designated for continuous power use or used in standby power applications.[418] Company data suggests that those engines used as standby or emergency generators are generally less than 300 horsepower (hp), and diesel engines used for onsite power generation are typically greater than 300 hp although this is not a firm cutoff for standby diesel generator capacities.[419] The size of diesel engines for drilling rigs are likely much larger. A 2014 drilling rig emission inventory prepared for the state of Texas found that the mechanical drill rig engine sizes ranged from 430 hp for vertical wells less than 7,000 feet deep to 1,094 hp for vertical wells greater than 7,000 feet deep.[420] The study also found that, in Texas, mechanical rigs (diesel engines) were used for 96% of shallow vertical wells (< 7,000 feet) and 80% of deep vertical wells (> 7,000 feet), whereas 86% of horizontal wells are drilled by electric rigs.[421] According to the Texas drilling rig report, the trend in new drilling rigs is mostly electric rigs especially for larger drilling rigs, meaning that diesel-fired electrical generating sets are used to power the drilling engines (rather than diesel engines driving the drilling engines).[422] The electrical rigs typically have three large identical diesel generators, with one of the three units designated for standby

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[417] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf.

[418] EPA, Alternative Control Techniques Document: Stationary Diesel Engines, March 5, 2010, at 13, *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf [hereinafter referred to as "EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE"]. Note, this ACT document expands upon the 1993 and 2000 ACT documents to address pollutants other than NOx.

[419] *Id.*

[420] Eastern Research Group, Inc., 2014 Statewide Drilling Rig Emissions Inventory with Updated Trends Inventories, Final Report, Prepared for Texas Commission on Environmental Quality, July 31, 2015, at 5-4, *available at:* https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821552832FY1505-20150731-erg-drilling_rig_2014_inventory.pdf.

[421] *Id.* at 4-1.

[422] *Id.* at 3-1.

capacity.[423] The Texas inventory report indicates that the typical size of electric generators to power the electric rigs is 1,338 hp.[424] This report was specific to Texas, and other states may have a different mix of size engines used for different types and depth wells. Diesel engine pumps are also used in hydraulic fracturing ("fracking"). In 2016, fracking accounted for 69 percent of all new oil and gas wells, according to the Energy and Information Administration.[425] Diesel engines used to power hydraulic fracturing pumps are generally in the range of 1,000–1,500 hp, with 8 to 12 pumps necessary per well site (total of 20,000+ hp per well site).[426]

A. CONTROL OPTIONS FOR DIESEL-FIRED RICE

Uncontrolled diesel RICE emit several pollutants that can contribute to regional haze, including NOx, particulate matter (PM), SO2, and VOCs. In some cases, the pollutant controls used for one pollutant can negatively or positively affect control of another pollutant. For example, combustion modifications employed to reduce NOx emissions will tend to increase PM emissions and VOC emissions, and vice versa. Controlling SO2, which is achieved by use of ultra-low sulfur diesel (ULSD) fuel, will reduce PM emissions as well. Thus, it can be important to evaluate pollution controls for diesel RICE holistically.

In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described NOx controls for diesel RICE, including combustion modifications (injection timing retard) and add-on controls (SCR), as follows:

> Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offers the potential for reduced NOx formation. … Achievable NOx reductions using IR is engine-specific but generally ranges from 20 to 30 percent. Based on an average uncontrolled NOx emission level for diesel engines of 12.0 g/hp-hr (875 ppmv), the expected range of controlled NOx emissions is from 8.4 to 9.6 g/hp-hr (610 to 700 ppmv).[427]

> Selective catalytic reduction applies to all CI engines and can be retrofit to existing installations except where physical space constraints may exist. … Based on an average uncontrolled NOx emission level of 12.0 g/hp-hr (875 ppmv) for diesel engines, the expected range of controlled NOx emissions is from 1.2 to 2.4 g/hp-hr (90 to 175 ppmv). … Limited emission test data show NOx reduction efficiencies of approximately 88 to 95 percent for existing installations, with ammonia slip levels ranging from 5 to 30 ppmv.[428]

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[423] *Id.*
[424] *Id.* at 5-4.
[425] https://www.eia.gov/todayinenergy/detail.php?id=34732.
[426] *See*, e.g., Solar Turbines, Turbomachinery Considerations in Drilling and Fracturing, Gas Electric Partnership 2013, at 7-8, *available at:* http://www.gaselectricpartnership.com/hReinerKurzTurboMachinery.pdf.
[427] EPA 1993 Alternative Control Techniques Document for RICE at 2-5 and 2-22.
[428] *Id.*

Compression-ignition diesel-fueled engines operate lean, meaning there is excess air during combustion. And while the application of similar control techniques can differ for spark-ignition (gas-fired) and compression-ignition (diesel-fired) engines, according to EPA's 1993 Alternative Control Techniques Document for RICE, the: (1) process; (2) application considerations; (3) performance factors; and (4) potential NOx emissions reductions for SCR applications with diesel engines are similar to those for natural gas applications.[429]

In its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, EPA discusses combining SCR with a particulate filter to reduce both NOx and PM emissions.[430] EPA describes diesel particulate filters (DPF) and catalyzed diesel particulate filters (CDPF) as follows:

> [DPF and CDPF] emission control technologies are designed to remove PM from the diesel engine exhaust stream using a wall flow filter material in which the exhaust gas must pass through a ceramic wall. In addition to PM, the catalyst in the CDPF also reduces emissions of [Total Hydrocarbons (THC)] and CO. … CARB reports PM emission reductions of 85 to 97 percent for various types of verified DPF or CDPFs. The EPA has verified DPF and CDPF systems that achieve up to 90 percent reduction. In addition to the PM reductions, the CDPF filter also reduces emissions of CO and THC by 90 percent but requires sufficient exhaust temperatures to facilitate regeneration by the catalyst. These reductions have been verified by both the CARB and EPA diesel control technology verification programs.[431]

CDPFs are thus a control device for PM and also for VOCs (THC) and CO.

Stationary diesel engine exhaust emissions include SO_2 due to sulfur in fuel, although a smaller percentage of the sulfur in fuel is converted to sulfates (particulate matter). At high temperatures, SO_2 can oxidize to form sulfates, contributing to further increases in PM emissions from engine exhaust. The use of ULSD fuel is essential in conjunction with exhaust treatment control technologies for reducing NOx and PM and is also, by itself, an effective and commonly applied way to reduce SO_2 emissions. Manufacturers require diesel engines equipped with CDPF to use ULSD fuel. EPA, in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, describes the use of ULSD as follows:

> EPA [] finalized NSPS for stationary CI engines that require all new stationary diesel engines to use ULSD in 2010. This ULSD fuel enables the use of aftertreatment technologies for new and existing diesel engines and can also by itself reduce emissions of criteria pollutants. The use of ULSD reduces the formation of sulfur oxides and particulate sulfates from the diesel engine exhaust. The reductions in PM are expected to be approximately 5 to 30 percent depending on the sulfur content of the fuel that is replaced. … It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.[432]

[429] EPA 1993 Alternative Control Techniques Document for RICE at 5-73.
[430] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.
[431] *Id.* at 32 and 34.
[432] *Id.* at 47 and 48.

In summary, while any one of these pollution controls can be used at a diesel RICE to control one pollutant, the co-benefits of using all of these controls together (ULSD, CDPF, and SCR) ensure the most effective control of NOx, PM, SO2, as well as CO and hazardous air pollutants.

B. EXISTING FEDERAL AIR REGULATIONS FOR DIESEL-FIRED RICE

The diesel engines that power and/or drive drill rigs and wellsite pumping operations may be considered to be nonroad engines (as opposed to stationary engines), if they meet the regulatory criteria to be considered a nonroad engine. According to EPA, a diesel engine is considered a nonroad engine if it is self-propelled or propelled while performing its function or portable or transportable (if it has wheels, skids, carrying handles, a dolly, trailer, or platform), although a nonroad engine becomes a stationary engine if it stays in one location for more than 12 months (or for a full annual operating period of a seasonal source).[433] EPA distinguishes between nonroad diesel engines and stationary diesel engines because the Clean Air Act directs EPA to set emission standards for new nonroad engines and generally does not allow states to set emission standards for nonroad engines except through a specific process outlined in Section 209 of the Clean Air Act.[434]

EPA has established emission limitations to decrease air emissions from nonroad diesel engines using a tiered approach, with the most stringent Tier 4 standards currently in effect for engine manufacturers. See 40 C.F.R. §§89.112, 1039.101, 1039.102. These are emission standards that the manufacturers must meet in their production and sale of diesel engines and for which they demonstrate compliance on a fleetwide basis. There have been four tiers of emission standards applicable to diesel RICE, with Tier 1 standards applying to engines constructed beginning in 1996-1998, Tier 2 standards applying in 2000-2004, Tier 3 standards applying in 2006-2008, and Tier 4 standards applying in approximately 2014 and beyond.[435] The emission standards do not specify any one pollution control technology that needs to be installed to meet the emission limitations. Instead, the standards set limitations on emissions. Generally, the Tier 1, 2, and 3 emission standards were met with advanced engine design, while the Tier 4 emission standards reflect application of CDPF and SCR.[436] These controls reduce PM and NOx emissions by over 90% from diesel RICE. In addition, the Tier 4 standards mandate that ULSD be used in Tier 4 engines.[437] This requirement also ensures reduced SO_2 emissions from diesel engines.

EPA has also established NSPS for stationary diesel engines (i.e., those diesel RICE not considered to be nonroad engines) in 40 C.F.R. Part 60, Subpart IIII. Those emission standards generally require engine manufacturers to meet the same emission standards applicable to nonroad diesel engines for the size and model year, beginning in model year 2007, for non-emergency engines of displacement below 10

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[433] *See* EPA's "Understanding the Stationary Engines Rules," at https://www.epa.gov/stationary-engines/understanding-stationary-engines-rules. *See also* 40 C.F.R. §89.2.
[434] Section 209(e)(2) of the Clean Air Act.
[435] *See*, e.g., https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf.
[436] *See*, e. g., EPA's Frequently Asked Questions from Owners and Operators of Nonroad Engines, Vehicles, and Equipment Certified to EPA Standards, available at https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100U8YP.pdf.
[437] 40 C.F.R. §1037.501(d)(2)

liters per cylinder.[438] Non-emergency engines of displacement higher than 10 liters per cylinder must generally meet the applicable emission standards for marine engines in 40 C.F.R. §94.8 which vary based on year of manufacturer and cylinder displacement.[439] Emergency engines that operate in emergency situations (like standby generators) do not have to meet the Tier 4 standards and instead must meet less stringent standards.[440]

The NSPS have separate requirements for owners or operators of stationary diesel engines that are generally not as stringent either in date of applicability or emission limits as the limits applicable to engine manufacturers. As summarized by an industry website, owners or operators of engines of pre-2007 model year must meet Tier 1 nonroad engine standards for engines less than 10 liters per cylinder and must meet Tier 1 marine standards for engines greater than or equal to 10 but less than 30 liters per cylinder.[441] For engines of 2007 model year or later, owners or operators of engines less than 30 liters per cylinder must buy engines that are certified to meet the NSPS standards applicable to manufacturers.[442] Owners or operators of 2007 model or later year engines greater than or equal to 30 liters per cylinder displacement must meet emission standards that vary depending on the year the engine was installed, with installations after January 1, 2016 having to meet emission limits reflective of application of DPF and SCR.[443]

Significantly, the NSPS do not apply to owners or operators of stationary diesel RICE that have been modified or reconstructed, nor do they apply to engines that were removed from one location and reinstalled at a new location.[444] Further, while the NSPS required by October 1, 2010 the use of ULSD fuel for those engines subject to the NSPS that are below 30 liters per cylinder displacement, engines with greater than or equal to 30 liters displacement that are subject to the NSPS are allowed to use 1,000 ppm sulfur content fuel.[445]

EPA has also adopted a National Emission Standard for Hazardous Air Pollutants for Stationary RICE (RICE NESHAP) that requires emission limits on CO that effectively also limit hazardous air pollutants and VOCs.[446]

[438] 40 C.F.R. §60.4201. Exceptions existing for engines operated in remote areas of Alaska and in marine offshore installations. 40 C.F.R. §60.4201(f).
[439] See 40 C.F.R. §60.4201.
[440] *See* 40 C.F.R. §60.4202.
[441] *See* https://dieselnet.com/standards/us/stationary_nsps_ci.php. *See also* 40 C.F.R. §60.4204(a).
[442] 40 C.F.R. §60.4204(b).
[443] 40 C.F.R. §60.4204(c).
[444] 40 C.F.R. §60.4208(i).
[445] 40 C.F.R. §60.4207.
[446] 40 C.F.R. Part 63, Subpart ZZZZ.

C. POLLUTION CONTROL UPGRADES OR RETROFITS FOR DIESEL-FIRED RICE

1. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH TIER 4 ENGINES

Given that manufacturers are currently producing diesel RICE with integrated SCR and DPF to meet EPA's Tier 4 emission standards, it is likely the more cost effective option to consider the replacement of existing engines with new Tier 4 engines rather than requiring retrofitting of pollution controls. The emission reduction benefits from replacing existing diesel RICE with Tier 4 diesel RICE can be quite significant. It is difficult to directly compare the regulatory emission standards for Tiers 1–3 to the Tier 4 emission standards because the Tier 2 and 3 emission standards for NOx were based on the total of non-methane hydrocarbons (NMHC) plus NOx. EPA's 2010 Alternative Control Techniques Document for Stationary Diesel Engines summarized the NOx and PM emission rates for various size ranges and for the Tiers 1, 2, and 3, based on EPA's Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling – Compression Ignition (EPA 420-P-04-009), April 2004.[447] In the table below, we compare "Tier 0" (pre-1998) and EPA's Tier 1, 2, and 3 emission factors to the emission standards of the Tier 4 standards promulgated by EPA for specific size engines that fall within the various size ranges of applicability for EPA's nonroad emission standards.[448] The table below shows the NOx and PM emission rates expected for each of the four Tiers of diesel RICE rules, as well as NOx and PM emissions from diesel RICE manufactured before the EPA emission standards applied (i.e., pre-1998 or "Tier 0").

[447] *See* EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3).
[448] *See* May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1, *available at:* https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.

Table 30. Comparison of NOx and PM Emission Rates for Various Engine Sizes and Tier Engines.[449]

ENGINE SIZE, HP	TIER ENGINE	NOX EMISSIONS, G/HP-HR	PM EMISSIONS, G/HP-HR
75	0	6.89	0.72
	1	5.58	0.47
	2	4.72	0.24
	3	3.00	0.30
	4	3.50[450]	0.02
174	0	8.39	0.40
	1	5.58	0.25
	2	4.00	0.13
	3	2.50	0.15
	4	0.30	0.01
600	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.30	0.01
750	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.60	0.15
	4	2.60	0.075
1500 GEN SET[451]	0	8.9	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.5	0.02

As shown in the above table, the Tier 4 NOx limits reflect significant NOx reductions from each prior Tier engine for some engine sizes, except the smallest engines and the non-electrical generating set engines that are greater than 750 hp in size for which there is no different between Tier 3 and Tier 4 NOx emissions. The PM emissions, on the other hand, get increasingly more stringent with each Tier engine.

To determine the cost effectiveness of replacing an existing engine with a Tier 4 engine, one needs to know the costs of a Tier 4 engine. A 2010 analysis done by CARB collected cost data from equipment manufacturers for Tier 4 compliant Generator-Set Engines (or "Gen Sets") and determined the average cost per horsepower for a Tier 4 engine equipped with DPF and SCR.[452] Although this CARB analysis was

[449] Data from EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3), and from May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.
[450] This limit applies to NMHC plus NOx. *See* https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.
[451] Generator-set engines or "Gen Sets." These engines are used to operate an electrical generator or an alternator to produce electric power for other applications.
[452] CARB, Analysis of the Technical Feasibility and Costs of After-Treatment Controls on New Emergency Standby Engines at B-11, *available at:* https://ww3.arb.ca.gov/regact/2010/atcm2010/atcmappb.pdf.

for emergency standby engines, the cost data can provide a reasonable estimate of the capital costs to purchase diesel RICE meeting Tier 4 standards. This data was collected in 2010, and thus presumably reflects a 2010 $ cost basis.[453] CARB provided an average cost per horsepower of Tier 4 engines installed with DPF and SCR as follows:

Table 31. Average Cost Per Horsepower for Diesel RICE Meeting Tier 4 Final Requirements[454]

HP RANGE	$/HP FOR NEW ENGINES MEETING TIER 4 FINAL STANDARDS (2010 $)
50-174	$250
175-749	$184
750-1,206	$160
1,207-2,000	$155
>2,000	$125

With this average cost per horsepower data, the average cost effectiveness of replacing an older engine with a Tier 4-compliance diesel engine can be estimated. For the purpose of this cost effectiveness analysis, a 10-year useful life was assumed. The useful life for the emissions warranty guarantee period required in EPA's nonroad diesel engine rules is only 10 years.[455] While we contend that it is likely a RICE unit including such an engine with SCR installed, can have a useful life of 20 years or more, it is not as clear that the diesel particulate filter would have a life of more than 10 years.[456] Thus, for the purpose of this cost effectiveness analysis, a 10 year life of the new Tier 4 engines was assumed. A 5.5% interest rate was also assumed to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[457] The bank prime rate fluctuates over time, and the highest it has been in the past 5 years is 5.5%.[458] Reductions in NOx and PM emissions with the replacement of existing diesel RICE with Tier 4 engines were based on the emission factors reflected in Table 30 above. Given that the Tier 4 engines have significantly lower emissions of both NOx and PM, the total of NOx plus PM emissions reduced were considered in calculating cost effectiveness. The table below provides the cost effectiveness of replacing either a pre-1998 or a Tier 1, 2, or 3 engine with a Tier 4 engine. Calculations were done assuming that the engines operate at two different levels: 1,000 hours per year and 4,000 hours per year. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.[459] However, EPA also presented information from other sources indicating the average operating hours of diesel RICE are as high as 3,790 hours per year.[460] Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE.

[453] *Id.* at B-11 and B-20.
[454] *Id.*, Table B-6.
[455] *See* 40 CFR 89.014.
[456] *See*, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at:* https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf.
[457] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[458] *See,* e.g., https://fred.stlouisfed.org/series/DPRIME.
[459]*See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.
[460] *Id.* at 56 (Table 5-1).

Table 32. COST EFFECTIVENESS OF REPLACING EXISTING DIESEL RICE WITH TIER 4-COMPLIANT DIESEL RICE (2010$).

ENGINE SIZE, HP	ANNUALIZED COST OF NEW ENGINE[461]	ENGINE REPLACED WITH TIER 4	COST EFFECTIVENESS OF REPLACEMENT, 1,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)	COST EFFECTIVENESS OF REPLACEMENT, 4,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)
75	$2,488	Tier 0	$6,544/TON	$1,636/TON
		Tier 1	$9,921/TON	$2,480/TON
		Tier 2	$15,517/TON	$3,879/TON
		Tier 3	$107,526/TON	$26,882/TON
174	$4,247	Tier 0	$2,610/TON	$653/TON
		Tier 1	$4,011/TON	$1,003/TON
		Tier 2	$5,794/TON	$1,448/TON
		Tier 3	$9,466/TON	$2,367/TON
600	$14,647	Tier 0	$2,610/TON	$653/TON
		Tier 1	$4,034/TON	$1,009/TON
		Tier 2	$5,646/TON	$1,412/TON
		Tier 3	$9,466/TON	$2,367/TON
750	$15,920	Tier 0	$3,147/TON	$787/TON
		Tier 1	$6,164/TON	$1,541/TON
		Tier 2	$12,368/TON	$3,092/TON
		Tier 3	$256,280/TON	$64,070/TON
1500 GEN SETS[462]	$30,845	Tier 0	$2,255/TON	$564/TON
		Tier 1	$3,534/TON	$883/TON
		Tier 2	$5,026/TON	$1,256/TON
		Tier 3	$8,760/TON	$2,190/TON

Because the NOx emission rates of the various Tier 1–4 standards did not always decrease to the same extent for the smallest and the mid-size to large (non-Gen Set) engines, the cost effectiveness of replacing an existing engine with a Tier 4 engine of 75 hp and of 750 hp increases significantly between installing a Tier 4 engine to replace a Tier 0, 1, or 2 engine as compared to a Tier 3 engine. Also, as would be expected, it is generally more cost effective to replace an engine that operates 4,000 hours per year compared to one that operates 1,000 hours per year. In any event, as Table 32 demonstrates, it should at least be considered cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine of any size or operating hours. For engines in the range of 174 hp to less than 750 hp that operate 4,000 hours or more per year, it is also clearly cost effective to replace any tier engine with a Tier 4 engine, as it also is cost effective for large generator set engines.

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[461] Based on the costs per horsepower given in Table 31 above and a capital recovery factor based on a 10-year life and a 5.5% interest rate of 0.132668.

[462] Generator sets > 1,200 hp have more stringent Tier 4 emission standards than other engines that are greater than 750 hp. *See* May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.

Although the above review focused on the cost effectiveness for the combined reductions of NOx plus PM, it is important to note that the EPA nonroad engine requirements also set emission limits on THC. Specifically, the Tier 4 standards set a THC emission limit that reflects an 87% reduction in THC compared to pre-1998 (Tier 0 levels). Further, only ULSD is to be used on Tier 4 engines. That is not only a legal requirement but, as discussed above, it is technically required by the manufacturer to ensure that the CDPF works effectively. The use of ULSD which is 15 ppm sulfur, compared to diesel fuel which may be 500 ppm sulfur, reflects a 97% reduction in SO2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.[463] Some states may already mandate the use of ULSD or it could be that ULSD is the only fuel available in some areas, so installation of a Tier 4 engine may not necessarily reduce SO2 emissions for all sources.

In terms of the non-air quality environmental and energy impacts associated with the replacement of an older engine with a Tier 4 engine, the impacts associated with the pollution controls could include increased fuel consumption due to reduced efficiency/parasitic load of SCR and CDPF and/or result in reduced power output. However, improvements in combustion efficiency that have been required and engineered into these newer engines also mean fuel savings that will make up for any parasitic loads, particularly for Tier 0 or Tier 1 engines replaced with Tier 4 engines. Other environmental impacts include solid waste disposal issues from spent catalysts. Further, the Tier 4 engines will require operator training and may result in increased maintenance, although the switch from higher sulfur diesel to ULSD which is mandated for use in Tier 4 engines will result in decreased maintenance. One likely benefit regarding maintenance associated with these controls when purchasing an engine with the NOx and PM controls built into the design as one package (as comparted to retrofitting an existing engine) is that the manufacturers will have a standard set of operating and maintenance procedures for each engine, whereas for a retrofit of SCR and/or CDPF to an existing diesel RICE, the operating and maintenance procedures will presumably need to be tailored to the specific make, model, and condition of the existing engine.

There are also other environmental benefits of replacing existing diesel engines with Tier 4 engines, particularly due to effects that increased engine efficiency and the use of a CDPF will have on reducing black carbon emissions from diesel RICE. Black carbon is very effective at absorbing solar energy. The black carbon particles in the atmosphere absorb solar energy and thus can warm the planet, although black carbon is considered a short-lived climate change pollutant.[464] And when the black carbon particles precipitate to surfaces of snow and ice, it reduces the reflecting power of the snow or ice which results in increased melting of snow and ice. The increased melting of the snow and ice results in a feedback loop with more land exposed to absorb, rather than reflect, solar energy, melting more snow and ice as well as permafrost that releases carbon trapped in the soils which further adds to climate change pollution.[465] Thus, the reduction in black carbon emissions by switching older diesel RICE with Tier 4 engines could have climate change benefits as well as visibility benefits.

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[463] *See* https://dieselnet.com/standards/us/nonroad.php.

[464] *See* https://oehha.ca.gov/epic/climate-change-drivers/atmospheric-black-carbon-concentrations; *see also* Cho, Renee, The Damaging Effects of Black Carbon, March 22, 2016, Earth Institute, Columbia University, *available at*: https://blogs.ei.columbia.edu/2016/03/22/the-damaging-effects-of-black-carbon/.

[465] *Id. See also* https://scied.ucar.edu/shortcontent/melting-ice-and-climate-change.

Given that manufactures were required to exclusively produce Tier 4 nonroad diesel engines by January 1, 2015, the Tier 4 engines should be readily available for purchase and installation, or be available in fairly short order. Thus, the replacement of an existing diesel RICE with a Tier 4 diesel RICE should presumably be able to be completed within six months to one year.

When EPA adopted the nonroad diesel engine emission standards, EPA envisioned that the nonroad diesel engine fleet would be comprised entirely of Tier 4 engines by 2030.[466] It is not clear whether the diesel RICE used in the oil and gas industry are on track to be operating on Tier 4 engines by 2030. As part of the process of evaluating controls to achieve reasonable progress towards the national visibility goal, States should evaluate the age and EPA emission compliance status (i.e., Tier) of existing diesel RICE operating within the oil and gas industry in the state. If states do not already collect such information, states should gather this information through required source inventory and/or source registration or licensure requirements.

It is clear that requiring replacement of existing diesel RICE with Tier 4 RICE engines is a cost effective control to reduce NOx and PM along with VOCs and SO_2 for many size engines in a range of operating hours. Requiring the replacement of existing diesel RICE with new Tier 4 engines along with requiring the use of ULSD fuel is the most readily implementable approach to reducing visibility-impairing emissions from diesel RICE.

It would be most effective to require use of Tier 4-compliant generator sets in conjunction with electric motors for all drilling operations, because large Gen Sets (which would be necessary to power electric drill rigs) are subject to much more stringent NOx limits than large diesel RICE (i.e., 0.5 g/hp-hr is the NOx limit for Tier 4 engines, compared to the 2.60 g/hp-hr NOx limit for large diesel RICE, as shown in Table 30 above). Indeed, the Superintendent of Carlsbad National Park has requested this approach as a mitigation measure for the Chevron U.S.A. Hayhurst Master Development Plan for which the western boundary of the project area was to be located only 17 kilometers from Carlsbad National Park in New Mexico. Specifically, the National Park Service stated that "[i]f this option were implemented, engines would meet the 0.5 g NOx/hp-hr [limit] and would reduce drilling and completion emissions by 90%."[467]

In summary, for stationary diesel RICE units, states should require the replacement of older existing engines with Tier 4 engines. For those diesel RICE that are considered nonroad engines, states should consider adopting emission requirements for diesel nonroad engines if California has adopted emission standards that have been approved by EPA under Section 209(e)(2) of the Clean Air Act, where the state adopts the same standards. Alternatively, a state can incentivize the replacement of existing nonroad engines with Tier 4 engines. Further, the state should otherwise encourage use of electric engines for drill rigs and the use of Tier 4 Gen Sets to power those electric engines, as that will result in the greatest reduction in NOx due to the lower emission limits that apply to Tier 4 Generator Set engines. States should evaluate all available options to, at the minimum, encourage replacement of older existing nonroad engines with Tier 4 engines.

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[466] *See*, e.g., EPA Progress Report on EPA's Nonroad Mobile Source Emissions Reductions Strategies, September 27, 2006, at 8, *available at:* https://www.epa.gov/sites/production/files/2015-11/documents/20060927-2006-p-00039.pdf.

[467] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 6.

2. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH NATURAL GAS-FIRED RICE

A second option for reducing emissions from diesel RICE is to replace the engines with natural gas-fired or dual-fuel RICE. This was another mitigation measure recommended by the National Park Service to the Bureau of Land Management for the Chevron U.S.A. Hayhurst Master Development Plan. Specifically, the National Park Service stated: "[b]oth natural gas-fired and dual-fuel engines have proven to be feasible, cost effective options for drilling operations in various basins throughout the United States and Canada [fn omitted]."[468] The National Park Service gave numerous examples of companies employing natural gas-fired or dual-fuel drill rig engines, including "EQT, Apache Corporation, Chesapeake Energy, Statoil, Encana Corporation, Cabot Oil and Gas, Antero Resources, CONSOL Energy and Seneca Resources."[469] The National Park Service specifically highlighted Chesapeake Energy's move to "transition all of its hydraulic fracturing equipment to [liquefied natural gas]."[470]

The Four Corners Air Quality Task Force (4CAQTF) also evaluated this option of using natural gas-fired engines on the drill rigs in the Four Corners region.[471] The 4CAQTF found that this switch from diesel RICE to lean burn RICE engines would result in approximately a 91% reduction in NOx from use of Tier 0 diesel engines and approximately an 85% reduction in NOx from use of Tier 1 diesel engines, but this was based on an assumed NOx emission rate from lean burn natural gas-fired RICE of 2 to 3 g/hp-hr.[472] As discussed in Section II.D. and E. of this report, use of LEC or SCR at lean burn engines is cost effective for lean-burn RICE and could achieve NOx emission rates of no higher than 2 g/hp-hr and more likely 1 g/hp-hr or even lower. Use of natural gas-fired RICE instead of diesel RICE would also significantly reduce SO_2 and PM emissions. The 4CAQTF report found that use of natural gas-fired RICE may be less expensive than diesel RICE if natural gas is located within close proximity and able to be piped to the natural gas-fired RICE.[473] Diesel fuel generally needs to be hauled to the drill rig, thus replacement of diesel RICE with natural gas-fired RICE would also reduce mobile source tailpipe and fugitive emissions associated with transporting the diesel fuel. The 4CAQTF report gave one example of a natural gas-fired drill rig being utilized in the Jonah Field in Wyoming to indicate that the use of natural gas-fired drill rigs is a technically feasible option,[474] which is clearly the case given the number of companies cited by the National Park Service that are employing natural gas-fired or dual-fuel drill rig engines.[475] The 4CAQTF indicated a capital cost of up to $1.2 million dollars per rig for the retrofit.[476] Some of the negative impacts included that the use of natural gas-fired RICE would increase carbon monoxide emissions by

[468] *Id.* at 7.
[469] *Id.*
[470] *Id.*
[471] See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 61, *available at:* https://www.env.nm.gov/wp-content/uploads/sites/2/2016/11/4CAQTF_Report_FINAL.pdf.
[472] *Id.*
[473] *Id.*
[474] *Id.* at 62.
[475] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.
[476] *Id.*

approximately 175%, and also that there could be increased land disturbance regarding the installation of natural gas pipelines for delivery of fuel.[477]

In summary, replacement of diesel RICE with natural gas-fired RICE is a viable control option for addressing the visibility-impairing emissions from diesel RICE that states should consider in evaluating reasonable progress measures for diesel RICE units.

3. RETROFIT OF DIESEL-FIRED RICE WITH AIR POLLUTION CONTROLS

Another option to control emissions from stationary diesel RICE is to require retrofits of specific pollution controls. Provided below are cost effectiveness analyses for SCR retrofits and for DPF retrofits to diesel RICE.

a) RETROFITTING SCR TO EXISTING DIESEL-FIRED RICE TO REDUCE NOx

EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE presented control costs for SCR and for CDPF retrofits at diesel RICE units. For SCR, EPA estimated capital costs at $98 per hp, based on industry data, and this included costs for the catalyst, reactor housing and ductwork, ammonia injection system, controls, and engineering and installation of the equipment.[478] EPA estimated annualized costs for SCR at $40 per hp, based on annualized capital costs and costs for operating/supervisory labor, maintenance, ammonia, steam diluent, and fuel penalty calculated using the EPA Control Cost Manual and based on 1,000 hours of operation per year.[479]

EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of NOx emissions from SCR, which should be readily achievable.[480] EPA estimates uncontrolled NOx emissions based on emission factors from modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). As discussed above, the Tier 4 standards reflect the NOx control levels achievable with SCR, and thus it would not make sense for EPA to evaluate SCR retrofits for a Tier 4 engine.

The following table shows the cost effectiveness, based on EPA's cost data, of retrofitting SCR to an uncontrolled stationary diesel RICE and to a Tier 1, 2, or 3 diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled NO_x emissions estimates. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.[481] However, EPA also presented information from other sources indicating the average operating hours of diesel RICE as high as 3,790 hours per year.[482] Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE. To estimate operating costs for operating at 4,000 hours per year, EPA's annual cost estimates for an engine

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[477] *Id.* at 61-62.
[478] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 57.
[479] *Id.*
[480] *Id.*
[481] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.
[482] *Id.* at 56 (Table 5-1).

operating 1,000 hours per year were multiplied by a factor of four to estimate potential annual costs reflective of engines operating closer to 4,000 hours per year. For the cost effectiveness analysis presented herein, the SCR system was assumed to have a life of 20 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.[483] To be consistent with EPA's statements on SCR and also considering the useful life of diesel RICE, this analysis will assume a 20-year life of the SCR. A 5.5% interest rate was used to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[484]

Table 33. Cost Effectiveness to Reduce NOx Emissions by 90% from Stationary Diesel RICE with SCR Operating 1,000 Hours per Year and 4,000 Hours per Year[485]

ENGINE SIZE, hp	ANNUALIZED COSTS OF SCR, 2005$	EMISSIONS STANDARD	COST EFFECTIVENESS OF SCR, 1,000 HOURS PER YEAR, 2005$	COST EFFECTIVENESS OF SCR, 4,000 HOURS PER YEAR, 2005$
75	$2,808	TIER 0	$5,474/ton	$4,575/ton
		TIER 1	$6,739/ton	$5,632/ton
		TIER 2	$8,021/ton	$6,703/ton
		TIER 3	$12,581/ton	$10,514/ton
238	$8,911	TIER 0	$4,500/ton	$3,761/ton
		TIER 1	$6,781/ton	$5,667/ton
		TIER 2	$9,430/ton	$7,881/ton
		TIER 3	$15,093/ton	$12,614/ton
675	$25,272	TIER 0	$4,500/ton	$3,761/ton
		TIER 1	$6,485/ton	$5,420/ton
		TIER 2	$9,207/ton	$7,694/ton
		TIER 3	$15,097/ton	$12,617/ton
1,000	$37,441	TIER 0	$4,497/ton	$3,759/ton
		TIER 1	$6,500/ton	$5,432/ton
		TIER 2	$9,204/ton	$7,692/ton
		TIER 3	$15,073/ton	$12,597/ton

[483] *See* EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[484] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[485] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were based on a 20-year life and a 5.5% interest rate. NOx emission reductions are based on 90% NOx removal efficiency, with uncontrolled emissions based on EPA estimates (EPA-420/P-04-09, 2004).

Lower cost data were reported by EPA in its 2000 Updated Information on NOx Emissions and Control Techniques for what it referred to then as 'modern SCR': "The vendor carried out a similar analysis for a 1,000 bhp diesel engine. For an engine operating 200 hours per year, the cost effectiveness was calculated at almost $4,000 per ton. For an engine operating 2,000 hours per year, the cost effectiveness dropped to less than $900 per ton."[486]

In its 1993 Alternative Control Techniques Document for RICE, EPA included a cost effectiveness analysis for diesel-fueled RICE with SCR operating 8,000 hours per year with costs as low as $690/ton for the largest engine sizes (4,000-8,000 hp). EPA noted costs of $1,000/ton or less for engines larger than 3,200 hp and costs of $3,000/ton or less for engines larger than 750 hp.[487]

It is clearly cost effective to retrofit SCR to diesel RICE units that emit NOx at levels similar to the older tier nonroad engines (*e.g.*, Tiers 0 or 1) even at low levels of operating hours per year. And, diesel RICE used in the oil and gas industry have been retrofitted with SCR to reduce NOx. For example, the state of Wyoming and the Bureau of Land Management coordinated with companies drilling in the Pinedale Anticline in western Wyoming to reduce NOx emissions from all drill rigs and, as a result, Shell Exploration and Production Company retrofitted 21 drill rigs with SCRs that have achieved 91-99% reduction in NOx emissions with low levels of ammonia slip (averaging 2-3 ppm).[488] There are several examples of successful SCR retrofits to diesel RICE, including for stationary diesel electrical generating sets and backup generators.[489]

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[486] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 5-13 referencing the following document: Manufacturers of Emission Controls Association. *Urea SCR for Stationary IC Engines*. Slides from a presentation to the NESCAUM Stationary Source and Permits Committee. October 6, 1999.
[487] *See* EPA's 1993 Alternative Control Techniques Document for RICE at 2-38 and Table 2-14 at 2-42.
[488] *See* Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 7 (Section 2.4), *available at:* http://www.meca.org/galleries/files/Stationary_Engine_Diesel_Retrofit_Case_Studies_1109final.pdf. *See also* Johnson Matthey, New system helps control NOx for Shell drill rigs, Pinedale Online, October 28, 2008, *available at:* http://www.pinedaleonline.com/news/2008/10/Newsystemhelpscontro.htm; and Johnson Matthey Catalysts, Application Fact Sheet, Case No. 801: Controlling NOx from Gas Drilling Rig Engine s with Johnson Matthey's Urea SCR System, *available at:* https://www.jmsec.com/fileadmin/user_upload/pdf/application_fact_sheets/engines/application_fact_sheet_801_-_shell_gas_drill_rig.pdf.
[489] *See* Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 14, 5-7 and 12.

The environmental and energy impacts of SCR systems for diesel RICE include the following:

- 0.5 percent increase in fuel consumption for SCR and associated air emissions increases[490]
- 1 to 2 percent reduction in power output for SCR[491]
- Increased solid waste disposal from spent catalysts[492]
- If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs.[493] If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply. It is likely that urea is the most common reagent used in SCR for diesel RICE

SCR technology is widely used at many industrial sources. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

In terms of length of time to install SCR, EPA has estimated that it takes 28-58 weeks to install SCR at a diesel-fired (lean-burn) RICE unit.[494]

b) RETROFITTING CDPF TO DIESEL-FIRED RICE TO REDUCE PM AND VOCS

For CDPF, EPA estimated capital and annual costs in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE based on cost equations developed for the RICE NESHAP. EPA's analysis was based on 2008 cost data from stationary diesel RICE retrofits. The following linear equation for annual cost includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

CDPF Annual Cost = 11.6 x ENGINE HP + 1,414 (2008$)

The capital cost equation for retrofitting a CDPF on a diesel engine was determined by EPA to be:

CDPF Capital Cost = 63.4 x ENGINE HP + 5,699 (2008$)

These relationships are derived from a data set that includes engines ranging from 40–1,400 hp.[495] EPA's cost estimates are based on 1,000 hours of operation per year.[496]

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[490] *See* EPA 1993 Alternative Control Techniques Document for RICE, 2-23 (Table 2-11).

[491] *Id.* at 2-23 (Table 2-11).

[492] Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).

[493] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.

[494] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.

[495] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 59.

[496] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 61.

EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of PM emissions from CDPF.[497] EPA estimates uncontrolled PM emissions based on emission factors from nonroad engine modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). In 2004, EPA adopted Tier 4 Standards, which were to be phased-in from 2008 to 2015. The Tier 4 Standards require 90 percent reduction of PM and NOx emissions. According to EPA, "[t]hese emission reductions can be achieved through the use of control technologies, including advanced exhaust gas aftertreatment, similar to those required by the 2007-2010 standards for highway engines."[498]

The following table shows the results of a cost analysis, based on EPA's cost data, of retrofitting CDPF to an uncontrolled stationary diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled PM emissions estimates. For this cost analysis of CDPF, a 10-year life and 5.5% interest rate. As discussed above, while we contend that it is likely a RICE unit can have a useful life of 20 years, it is not as clear that the diesel particulate filter would have a life of more than 10 years.[499] Therefore, a useful life of a CDPF retrofit was assumed to be 10 years in determining annualized costs of CDPF. A 5.5% interest rate was also assumed to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[500] To estimate annual operating costs for operation of CPDF at 4,000 hours per year, EPA's annual cost estimates which were based on 1,000 operating hours per year were multiplied by a factor of four.

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[497] *Id.*

[498] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 22.

[499] *See*, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at:* https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf.

[500] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

Table 34. Cost Effectiveness to Reduce PM Emissions by 90% from Stationary Diesel RICE with CDPF Operating 1,000 Hours per Year and 4,000 Hours per Year[501]

ENGINE SIZE, hp	ANNUALIZED COSTS OF CDPF, 2008$	EMISSIONS STANDARD	COST EFFECTIVENESS OF CDPF, 1,000 HOURS PER YEAR, 2008$	COST EFFECTIVENESS OF CDPF, 4,000 HOURS PER YEAR, 2008$
75	$1,670	TIER 0	$31,088/ton	$10,155/ton
		TIER 1	$47,467/ton	$15,505/ton
		TIER 2	$93,735/ton	$30,619/ton
		TIER 3	$74,837/ton	$24,445/ton
238	$2,955	TIER 0	$31,265/ton	$10,510/ton
		TIER 1	$49,665/ton	$16,696/ton
		TIER 2	$95,155/ton	$31,988/ton
		TIER 3	$83,321/ton	$28,010/ton
675	$6,397	TIER 0	$23,774/ton	$8,150/ton
		TIER 1	$43,343/ton	$14,860/ton
		TIER 2	$72,608/ton	$24,892/ton
		TIER 3	$63,467/ton	$21,759/ton
1,000	$8,958	TIER 0	$22,468/ton	$7,740/ton
		TIER 1	$40,960/ton	$14,110/ton
		TIER 2	$68,644/ton	$23,646/ton
		TIER 3	$59,960/ton	$20,654/ton

It must be noted that the higher cost effectiveness values for CDPF in comparison to SCR cost effectiveness values are due to the magnitude of PM emissions from diesel RICE being much lower than the NOx emissions from diesel RICE. The capital costs of CDPF range from $10,000 to $70,000, which is somewhat lower than the range of capital costs for SCR (which range from $7,300 to $100,000), and the annual operating costs of CDPF are significantly lower than the operating costs of SCR ($800-$3,200 per

[501] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were calculated assuming a 10-year life of controls and a 5.5% interest rate. NOx emission reductions are based on EPA's assumed 90% removal efficiency. Uncontrolled NOx emissions are based on EPA estimates (EPA-420/P-04-09, 2004).

year for CDPF compared to $2,200 to $29,000 per year for SCR).[502] Although CDPF can achieve greater than 90% reduction of PM, overall the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR.

To truly understand whether this control is considered cost effective, one has to evaluate whether similar sources have been required to install the control at similar costs. Indeed, there are several examples of diesel particulate filter systems being retrofitted to diesel RICE.[503]

As previously stated, the use of a CDPF requires the use of ULSD fuel. It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.[504] The use of ULSD which is 15 ppm sulfur, compared to higher sulfur diesel fuel which may be of 500 ppm sulfur content, reflects a 97% reduction in SO_2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.[505] EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE estimated that using ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.[506]

The environmental and energy impacts of controls for stationary diesel RICE include the following:

- 1 to 2 percent fuel penalty for CDPF[507]
- Increased solid waste disposal from spent catalysts[508]

The CDPF will have an added benefit of reducing VOCs and associated air toxics. EPA has found that CDPF can reduce THC by 90 percent.[509] Thus, CDPF can be considered a top control technology for both PM and VOCs.

CDPF can be installed fairly quickly. EPA has indicated that diesel particulate filters can be installed in less than a day,[510] although this claim likely pertains to onroad diesel engines (i.e., trucks). Nonetheless, it is the same technology whether applied to a mobile source or a larger generating diesel RICE. It can be assumed that even taking into account time for engineering, design, ordering of parts, etc., the time to install a CDPF is likely under a year.

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[502] These costs reflect the range of capital and operating costs for the engine sizes evaluated in Tables 33 and 34, using EPA's SCR and CDPF cost calculations from its 2010 Alternative Control Techniques Document for Stationary Diesel RICE.
[503] *See* Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.
[504] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 47 and 48.
[505] *See* https://dieselnet.com/standards/us/nonroad.php.
[506] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.
[507] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.
[508] Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).
[509] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 32 and 34.
[510] *See* https://www.epa.gov/sites/production/files/2016-03/documents/420f10028.pdf.

D. EXAMPLES OF STATE AND LOCAL AIR AGENCY RULES FOR EXISTING DIESEL-FIRED RICE

States and local air agencies have adopted NOx limits for diesel RICE, some of which have been in place for over 20 years. In Table 35 below, we summarize some of the stronger state and local air pollution requirements. Note that this is not a comprehensive list of state and local air regulations for diesel RICE.

California has adopted fleet-wide emission requirements for existing diesel "off-road" (i.e., non-road) diesel-fueled engines of 25 hp or greater (*see* Title 13 California Code of Regulations Sections 2449 through 2449.2), and EPA has authorized those rules under Section 209(e) of the Clean Air Act.[511] The goal of this program is to turnover nonroad diesel RICE to Tier 4 engines. The rule established in-use statewide emission performance standards that apply to any person owning and operating a nonroad diesel engine in California of 25 hp or greater. The fleet requirements phase in over time and require that fleets either meet fleet average emission targets or meet best available control technology (BACT). States may be able to adopt requirements like this for nonroad diesel RICE, pursuant to Section 209(e)(2) of the Clean Air Act.

Table 35 is a summary of the stronger NOx emission limits required of diesel RICE in states and local air districts across the United States. It is important to note that these are limits that generally do not apply to portable or nonroad engines, unless clearly stated otherwise. The most broadly applicable NOx limit required is approximately 1.10 g/hp-hr which applies in several air districts in California, although SCAQMD has adopted a more stringent NOx limit of 0.15 g/hp-hr. Those limits all likely reflect application of SCR to diesel RICE. These limits were adopted generally to meet RACT and BARCT (in California) and, as previously discussed, costs are taken into account in making these RACT and BARCT determinations. Thus, the fact that state and local air agencies have adopted emission limits reflective of SCR indicate that these agencies have found SCR to be a cost effective control to retrofit to existing stationary diesel RICE.

Table 35. State/Local Air Agency Diesel RICE Rules for NOx Emissions[512]

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
CA-Bay Area AQMD[514]	Reg. 9, Rule 8 Effective 1/1/2012: >50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable:	51 to 275 bhp	180 ppmvd (2.47 g/hp-hr)
		>175 bhp	110 ppmvd (1.51.g/hp-hr)

[511] 78 Fed. Reg. 58090-58121 (Sept. 20, 2013).
[512] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.
[513] Emission limits that are in ppmvd are at @ 15% oxygen.
[514] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-8-nitrogen-oxides-and-carbon-monoxide-from-stationary-internal-combustion-engines/documents/rg0908.pdf?la=en.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
CA-Mojave Desert APCD[515]	Rule 1160 (Amended 1/22/18)	>50 bhp &/or >100 hours/4 quarters, not portable, not subject to Airborne Toxic Control Measure, and only if located in the Federal Ozone Nonattainment area	80 ppmv (1.09 g/hp-hr)
CA-Sacramento AQMD[516]	Rule 412	>50 bhp with exemptions if portable, or if operated less than certain # of hours which vary based on rating of engine	80 ppmv (1.10 g/hp-hr) Alt Limit: 90% NOx reduction
CA-San Joaquin Valley APCD[517]	Rule 4702 Exemptions for <50 bhp, portable, or low use engines Non-EPA certified Compression Ignition Engines installed on or before 6/1/06. ----------------------	>50 & ≤ 500 bhp	EPA Tier 3 or Tier 4 by 1/1/2010
		>500 & ≤750 bhp and < 1000 hrs/yr	EPA Tier 3 by 1/1/2010
		>750 bhp & < 1000 hrs/yr	EPA Tier 4 by 7/1/2011
		>500 bhp & ≥1000 hrs/yr	80 ppmv (1.10 g/hp-hr)
		EPA Tier 1 or 2 engine	EPA Tier 4 by 1/1/2015 or 12 years after install date, but no later than 6/1/2018.
	Applicable to EPA-certified CI Engines	EPA Tier 3 or Tier 4 engine	Meet certified CI engine standard at time of installation
SCAQMD[518]	Rule 1110.2 As amended 11/1/2019	>50 bhp and not nonroad engines or portable (except portable generators that provide primary or supplemental power to a building, facility,	11 ppmvd (0.15 g/hp-hr)

515 https://ww3.arb.ca.gov/drdb/moj/curhtml/r1160.pdf.
516 http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf.
517 https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf.
518 http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
		stationary source, or stationary equipment, which are not exempt from the NOx limit)	
CA- Ventura County AQMD[519]	Rule 74.9	>50 bhp & > 200 hrs/yr Does not apply to diesel engines with permitted capacity factor ≤ 15%	80 ppmvd (1.10 g/hp-hr) or 90% NOx reduction
TX- Houston-Galveston-Brazoria Area[520]	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo The following limits apply to "stationary engines" (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after 10/1/01, that were installed, modified, reconstructed, or relocated on or after the date specified:	≥50hp & <100 hp, on or after 10/1/2007	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 10/1/2006	2.8 g/hp-hr
		≥750 hp, On or after 10/1/2005	4.5 g/hp-hr
		≥300 hp & < 600 hp, On or after 10/1/2005	2.8 g/hp-hr
TX- Dallas -Ft. Worth Area[521]	30 TAC 117.2110(3) Emission Specs for 8hr ozone demo The following limits apply to "stationary" diesel engines (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after	≥50hp & <100 hp, on or after 3/1/2009	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 3/1/2009	2.8 g/hp-hr
		≥750 hp, On or after 3/1/2009	4.5 g/hp-hr

519 http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf.
520 https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.
521 http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
	3/1/09, that were installed, modified, reconstructed, or relocated on or after the date specified:	Alternative limit to above for units with an annual capacity factor of ≤.0383	0.060 lb/MMBtu
MI[522]	R 336.1818 Applies to stationary engines	>1 ton/day NOx engines per avg ozone control period day in 1995	2.3 g/bhp-hr
NY[523]	6 CCR-NY 227-2.4 (f)(3) Applies to stationary engines	≥ 200 bhp in a severe ozone nonattainment area or ≥400 bhp outside a severe NAA	2.3 g/bhp-hr
WI[524]	NR 428.22(1)(i) Exemptions for low operating unit engines or for engines certified to meet federal nonroad emission standards.	≥500 hp	2.0 g/bhp-hr
MO[525]	10 CSR 10-5.510(3)(D)3.B. Applies in St. Louis ozone nonattainment area, to installations with potential to emit ≥100 tpy that operate more than 750 hours annually or more than 400 hours during ozone season	≥1800 hp	2.5 g/hp-hr
OH[526]	OAC Chapter 3745-110-03(F)(3) Applies in counties around Cleveland ozone nonattainment	≥2,000 hp	3.0 g/hp-hr

[522] https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf.
[523] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[524] http://docs.legis.wisconsin.gov/code/admin_code/nr/400/428.pdf.
[525] https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf.
[526] https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-02_Final.pdf.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
	area, to stationary engines at a facility with potential to emit ≥100 tpy		

E. SUMMARY – CONTROL OPTIONS FOR DIESEL-FIRED RICE UNITS

Based on all of the analysis provided above, there are several options for reducing visibility-impairing emissions from diesel-fired RICE units. These options are as follows, in order of most beneficial for reducing visibility-impairing pollutants from this source category:

1) Replace existing older diesel-fired engines with Tier 4 engines.

   Replacement of existing older diesel-fired RICE with Tier 4 engines is cost effective as shown in Table 32 above, and has the benefit of reducing NOx by 49% to 96% and PM by 81% to 97.5% (with the percentage reduction based on the emission rates the existing engines is complying with). Replacement of older diesel RICE with Tier 4 engines will also result in a reduction in VOC emissions, due to the VOC emission limits required of Tier 4 engines, and it will also reduce SO_2 emissions because ULSD fuel is required for Tier 4 engines.

   The cost effectiveness of replacing existing diesel-fired RICE varies based on the size of the engine being replaced (smaller engines and larger engines that are not electrical generating sets have less stringent Tier 4 emission limits, which impacts cost effectiveness for those engines, and also the annual operating hours impact cost effectiveness). In general, as demonstrated in Table 32 above, it is cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine for any size engine including for those engines operating on the lower end of annual operating hours.

   For drill rigs, it is most preferable from an air emissions perspective to replace existing older diesel-fired drill rigs with electric-motor drill rigs that are powered by a Tier 4 Electrical Generating Set. Tier 4 Electrical Generating Set engines greater than 1,500 hp are required to meet the lowest NOx and PM emission rates, significantly lower than large non-electrical generating engines (as shown in Table 30 above). Thus, installing electric drill rigs that are powered by Tier 4 electrical generating diesel RICE will result in the greatest reduction in visibility-impairing emissions if the only option is to continue to power the engines with diesel fuel.

2) Replace existing diesel-fired RICE with natural gas-fired RICE equipped with LEC or SCR. Replacing existing older diesel-fired RICE with natural gas-fired RICE, particularly those equipped with LEC or SCR, is also a very effective method for reducing NOx emissions by 85% to 95% and also significantly reducing if not eliminating SO_2 and PM emissions. While we did not calculate

the cost effectiveness of this control option, it is significant to note that the National Park Service has highlighted several companies that employ natural gas-fired or dual fuel drill rig engines,[527] and such engines are also being used in the Jonah Field in Wyoming.[528]

3) As a third option, existing diesel RICE can be retrofit with SCR and/or with CDPF. As demonstrated in Table 33, it is most cost effective to retrofit SCR to an existing Tier 0 or Tier 1 engine, and SCR can result in NOx emission reductions of 90% or more. And, as shown in Table 35, several California air districts have adopted NOx emission limitations that would require retrofitting of SCR to diesel RICE.

   In addition, CDPF can be retrofit to existing diesel RICE and achieve greater than 90% reduction of PM as well as reductions in VOC emissions. It must be noted that, overall, the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR- but that does not mean it is has not been considered a cost effective control. There are several examples of diesel particulate filter systems being retrofitted to diesel RICE.[529]

   Existing diesel-fired RICE should also be required to use ULSD fuel. EPA estimated that use of ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.[530] ULSD fuel is prevalent in the available fuels today and may already be required to be used in some areas/states. It is also required by the CDPF manufacturer to use ULSD fuel.

Thus, there are several options to cost effectively reduce emissions from diesel-fired engines used in the oil and gas industry. States must evaluate all available options for addressing this significant source of NOx, SO_2, PM and VOC emissions as part of their reasonable progress analysis. The most preferable options are those that address all of the visibility-impairing pollutants from this source category, with replacement of older diesel-fired engines with Tier 4 engines or replacing diesel-fired engines with natural gas-fired RICE equipped with LEC or SCR as the most effective emission limiting options.

VII. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED HEATERS AND BOILERS

Natural gas-fired heaters and boilers are used in a variety of applications, including power generation and the production of process heat and steam. Boilers, reboilers, and heaters can be found throughout the production and processing segments of the oil and gas industry.

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527 *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.

528 See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 62.

529 *See* Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.

530 EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.

In oil and gas production and processing, heaters can be used to aid in separation (e.g., heater-treaters, gas production units (GPUs), heated flash separator units),[531] to maintain temperatures within pipes / connectors (e.g., line heaters),[532] to maintain storage tank temperatures (e.g., tank heaters), and as regenerators / reboilers (e.g., glycol dehydrators, desiccant dehydrators).[533,534] These smaller integrated units are generally rated at less than about 2.5 million Btu per hour (MMBtu/hr) heat input.[535] Larger units can be found at gas processing plants, including steam boilers, hot oil heaters, fractionation column heaters, and other process heaters that range in size from a few MMBtu/hr to 100 MMBtu/hr heat input, or more.[536]

There are two basic ways of supplying combustion air to these types of external combustion units (i.e., two draft types): (1) natural draft (i.e., atmospheric units); and (2) mechanical or forced draft. In atmospheric units, the pressure difference between the hot stack gases and the cooler ambient air creates a draft, drawing supply air into the burners. These units are open to the atmosphere (i.e., non-sealed units). Mechanical draft units use a fan to introduce combustion air into the burners. Draft type can affect the level of excess air in the combustion chamber, and the resulting emissions from the unit (e.g., NOx emissions are generally lower in mechanical draft units by operating with lower excess air and improved flame characteristics).

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[531] Heater-treaters consist of a heater, free-water knockout, and oil/condensate and gas separator. GPUs consist of a heater and a separator to remove liquid from gas prior to further processing. Heated flash separators are equipped with small boilers to facilitate condensate removal through flashing.

[532] In-line heaters are used to maintain temperatures as pressure decreases, in order to prevent formation of hydrates. Note, in-line heaters can also be used to heat gas transmission lines further downstream in the oil and gas industry.

[533] Glycol dehydrators use glycol to remove water from the gas stream in order to prevent corrosion and freezing; small reboilers are used to regenerate the glycol. Dehydrators can be located at well pads, as well as at centrally-located gathering stations and processing facilities. Solid-desiccant dehydrators are generally used for large volumes of gas, e.g., downstream of a compressor station and use a heater to regenerate the desiccant.

[534] Dehydrator use varies depending on the moisture content of the gas; dry gas requires little dehydration. For example, according to the *Four Corners Air Quality Task Force Report of Mitigations* (Oil and Gas Section), "[i]n the [coal bed methane] areas of Colorado the gas is predominantly methane and the gas is relatively dry gas and requires little dehydration . . . Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required." *See* p. 90.

[535] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for Heater-Treater Source Category, completed for the 1st round RH plans [hereinafter referred to as "CDPHE RP for Heater-Treaters"], *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Heater-Treaters_1.pdf; *also see* PA DEP PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) and the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* p.52, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[536] Hot oil heaters, or thermal fluid heaters, are used in the oil and gas industry in combination with a heat exchanger to warm up a secondary fluid (gas or liquid). This can be useful in situations with certain temperature limitations (e.g., amine used to remove H_2S can degrade at high temperatures) or to prevent corrosive fluids from degrading heating coils. Fractionation column heaters are used at natural gas processing plants to separate out natural gas liquids for further use and can be larger than 10 MMBtu/hr.

Natural gas-fired external combustion units are sources of NOx, CO, VOC, and particulate matter emissions, with NOx the primary pollutant and the focus of this section. SO_2 emissions may also occur if the field-gas used to fire the heaters contains H_2S, which converts to SO_2 during combustion. While emissions from natural gas-fired heaters (e.g., heater-treaters, line heaters, tank heaters, and reboilers) may be relatively small on a unit level, compared to other combustion sources at oil and gas production and processing sites, these units may operate continuously throughout the year. And cumulative emissions from all of the heaters in use at an oil and gas production site or processing facility can be significant.

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the Heater-Treater Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[537] In its evaluation, Colorado reported that, "the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NOx emissions that are projected to be the largest single area source category in Colorado by 2018."[538] Colorado projected NOx emissions in 2018 would reach close to 23,000 tons per year.[539]

Federal standards, in the form of NSPS and NESHAP, exist for industrial boilers and process heaters. The NSPS for industrial-commercial-institutional steam generating units are outlined in 40 C.F.R. Part 60, Subparts Db and Dc, and apply to boilers that are capable of combusting over 10 MMBtu/hr of fuel (burning coal, oil, natural gas, or wood). Subpart Db covers industrial-commercial-institutional steam generating units with heat inputs greater than 100 MMBtu/hr and that commenced construction after September 18, 1978. Subpart Dc covers smaller industrial-commercial-institutional steam generating units that commenced constructed after June 9, 1989. These NSPS include emission standards for sulfur oxides (SOx) and PM from burning fuels other than natural gas. In addition, there are no performance testing standards for boilers burning only natural gas. EPA also regulates VOC emissions from boilers and process heaters that are used as combustion control devices under Subpart OOOO and OOOOa through VOC emission reduction requirements, operating requirements, performance testing and monitoring requirements.[540] The NESHAP for industrial boilers, commercial and institutional boilers, and process heaters is outlined in 40 C.F.R. Part 63 Subpart DDDDD and controls mercury, hydrogen chloride, particulate matter (as a surrogate for non-mercury metals), and CO (as a surrogate for organic hazardous emissions) from coal-fired, biomass-fired, and liquid-fired major source boilers based on the maximum achievable control technology. However, these requirements will not address NOx emissions. In addition, all major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

When EPA adopts or revises Federal standards for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally-applicable emission standards and not a source-specific evaluation of controls. It is necessary to evaluate if more broadly applicable and more stringent requirements and pollution controls are available to achieve reasonable progress towards the national

[537] *See* CDPHE RP for Heater-Treaters.
[538] *Id.* at 1.
[539] *Id.*
[540] *See, e.g.,* 40 C.F.R. Part 60 Subpart OOOOa §§ 60.5412, 60.5412a, 60.5413a, 60.5417a.

visibility goal, especially because the NSPS and NESHAP standards have not been re-evaluated in at least 8 years. Review of state regulations, particularly to address the NAAQS which require reductions in emissions from *existing* sources, is also necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided in this section for heaters and boilers reflects a review of the available pollution controls and techniques and associated emissions levels applicable to these source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the useful life of the emission source being evaluated.

Uncontrolled Emission Factors from Natural Gas-Fired External Combustion Units

NOx emissions from natural gas-fired heaters and boilers are generally expressed as emission rates in pounds per million Btu heat input (lb/MMBtu) or pounds per million standard cubic feet of gas (lb/MMscf) or as a concentration in parts per million by dry volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 3% oxygen. The following emission factors are used in this section:

EPA Emission Factor
AP-42 Natural Gas Combustion (Section 1.4, last revised 1998)
Small Boilers <100 MMBtu/hr (Uncontrolled)……………………………….…100 lb/MMscf (0.098 lb/MMBtu)
Converted to lb/MMBtu based on fuel heating value of 1,020 Btu/scf

SCAQMD Emission Factor
Units ≤2 MMBtu/hr …………………………………………………………….………110 ppmv (0.136 lb/MMBtu)
SCAQMD derived an average emission rate to calculate baseline emissions for this size category in its implementation studies for Rule 1146.2 Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters. This factor accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep.[541]

[541] *See* SJVAPCD Final Draft Staff Report with Appendices For Proposed Amendments to Rule 4308 (November 5, 2009), B-4, *available at:* http://www.valleyair.org/board_meetings/GB/agenda_minutes/Agenda/2009/November/Agenda_Item_26_Nov_5_2009.pdf [hereinafter referred to as "SJVAPCD 2009 Final Draft Staff Report for Rule 4308"].

A. COMBUSTION MODIFICATIONS

Combustion modification—such as flue gas recirculation (FGR), low-NOx burners (LNB), and ultra-low NOx burners (ULNB)—reduce NOx formation by controlling the combustion process. The following is EPA's description of these combustion control techniques:

> Staging techniques are usually used by LNB and ULNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB's create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean primary combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures. The secondary combustion zone is fuel-rich. Ultra-low-NOx burners use staging techniques similar to staged-fuel LNB in addition to internal flue gas recirculation. Flue gas recirculation returns a portion of the flue gas to the combustion zone through ducting external to the firebox that reduces flame temperature and dilutes the combustion air supply with relatively inert flue gas.[542]

Retrofitting natural gas-fired heaters and boilers with LNB was identified by EPA in 1998 as one of the two most prevalent control techniques in its AP-42 Emission Factor documentation, along with FGR.[543] EPA states that, "NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners."[544] And EPA further states that, "[w]hen low NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent."

CARB, in its 1991 RACT and BARCT determinations for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, also identified LNB as one of four control methods (along with FGR, SCR, and selective noncatalytic reduction (SNCR)).[545] CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input) a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would "need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems."[546] However, these determinations were from 1991, and the NOx removal capabilities of low NOx burners and similar combustion controls for NOx has greatly improved over time.

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[542] EPA-453/R-93-034 Alternative Control Techniques Document—NOx Emissions from Process Heaters (Revised), September 1993, p.2-6, *available at:* https://www3.epa.gov/ttncatc1/dir1/procheat.pdf [hereinafter referred to as EPA 1993 ACT for Process Heaters].

[543] EPA, AP-42, Section 1.4.4 (last revised 1998), *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.

[544] *Id.*

[545] CARB Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, July 18, 1991, p. 7 *available at:* https://ww3.arb.ca.gov/ractbarc/boilers.pdf [hereinafter referred to as "CARB 1991 Guidance"].

[546] CARB 1991 Guidance at 6.

For example, in 2018, California's SCAQMD concluded the following with regard to ULNB technology and its ability to meet very low NOx emission limits across a wide range of unit sizes:

> It was noted in the 2008 Rule 1146 and 1146.1 staff reports that there was clear evidence that these types of [ultra-low NOx] burners had been successfully retrofitted on boilers and heaters in the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) in their Rule 4306. Source tests that were conducted in conjunction with Rule 4306 showed a 98% compliance rate with a 9 ppm NOx limits using ultra-low NOx burners. In 2010, staff published a technology assessment report discussing the implementation assessment of ultra-low NOx burners subject to Rules 1146 and 1146.1. **The report concluded that the 9 ppm NOx limit can be achieved by ultra-low NOx burner systems for boilers and process heaters greater than 2 MMBtu/hour.** There were ultra-low NOx burners from 16 different manufacturers that could achieve the 9 ppm NOx compliance limit.[547]

In 2010, California's Sacramento Metropolitan AQMD (SMAQMD) determined, based on SCAQMD's rules for similar size sources and models being sold that meet SCAQMD limits, that ULNB technology was available to meet emissions limits for very small units, less than 1 MMBtu/hr.[548] Specifically, SMAQMD found that very small units less than 1 MMBtu/hr could meet a NOx limit equivalent to 20 ppmv:

> The proposed standards are technically feasible. The low NOx technology is commercially available and widely used. Additionally, these standards have already been adopted by the South Coast AQMD and the Bay Area AQMD, and except for the limits proposed for 2013 (which take effect for the SCAQMD in 2012), are already in effect in SCAQMD. As documented in the SCAQMD staff report for Rule 1146.2, as of 2006, 18% of the certification tests for units between 75,000–400,000 Btu/hr and 44% of the certification tests for units between 400,000 and 2,000,000 Btu/hr were already meeting the 14 ng/J (20 ppmv) standard. SCAQMD currently keeps a list of well over 100 certified models that are complaint with the standards in Rules 1146.2 and 1121.[549]

SMAQMD concluded that, "[t]he proposed emission limits are readily achievable through the use of low NOx burners."[550]

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[547] SCAQMD Draft Staff Report Rules 1146, 1146.1, 1146.2, and 1100, p. 2-2 [emphasis added], *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/rule-1146-1146.1-and-1146.2/dsr-1146-final.pdf?sfvrsn=6 [hereinafter referred to as "SCAQMD 2018 Draft Staff Report"].

[548] SMAQMD Staff Report Rule 414 Water Heaters, Boilers and Process Heaters Rated Less Than 1,000,000 Btu Per Hour, January 15, 2010, p. 5, *available at:* http://www.airquality.org/ProgramCoordination/Documents/Rule414%20StaffReport%20011510.pdf [hereinafter referred to as "SMAQMD 2010 Rule 414 Staff Report"].

[549] *Id.* at 16.

[550] *Id.* at 13.

In 2015, a Ventura County Air Pollution Control District (VCAPCD) analysis for amendments to its rules for boilers, steam generators, and process heaters ≥2 and <5 MMBtu/hr found:

> Ultra-low NOx burner systems can achieve less than 9 ppm NOx for boilers, steam generators, or process heaters without the use of Flue Gas Recirculation (FGR) systems. Source tests performed by the San Joaquin Unified Air Pollution Control District showed a 95 percent compliance rate with 9 ppm limits using ultra-low NOx burners. The average NOx concentration measured was 7 ppm.[551]

And as recently as April 2019, Santa Barbara County APCD concluded the following about the ability of ULNB technology to achieve lower NOx limits of between 9 and 12 ppm for units between 2–5 MMBtu/hr:

> The focus of this rule amendment is to lower the emission limits for new and modified natural gas and field gas units from 30 ppm to the 9-12 ppm NOx emission limits, beginning on January 1, 2020. To meet these lower standards, most boilers will have to be equipped with ultra-low NOx burners. Ultra-low NOx burners are designed to achieve low emissions while maintaining good flame stability and heat transfer characteristics. Furthermore, these burners may increase thermal efficiencies by reducing the amount of excess air needed for combustion. This has the added benefit of reducing fuel usage, which results in energy savings.
>
> For most systems, a blower will be required to mix the fuel and air prior to combustion. Even atmospheric boilers, where the burners are not totally enclosed, may still need a blower to premix the fuel and air. Due to the design criteria of these atmospheric boilers, it is only feasible to have them reach the 12 ppm NOx limit, as opposed to the 9 ppm limit for non-atmospheric boilers. It is possible to reach both the 9 and 12 ppm NOx limits without the use of Flue Gas Recirculation (FGR), yet some operators may still choose to use this technology.[552]

Thus, in rulemakings enacted in California air districts from 2015 to 2019, it was essentially deemed reasonable to impose a NOx emission limit of 9 ppm for natural gas-fired heaters and boilers with heat input capacities greater than or equal to 2 ppm. However, as will be discussed in Sections B. and F., even lower NOx limits have been required for heaters and boilers in some California Air Districts.

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[551] VCAPCD Staff Report Amendments to Rule 74.15.1 Boilers, Steam Generators and Process Heaters June 23, 2015, p. 4, *available at*: http://www.vcapcd.org/pubs/Rules/74151/201506/Staff-Report-Rule-74-15-JUNE-23-%202015.pdf [hereinafter referred to as "VCAPCD 2015 Staff Report"].

[552] Santa Barbara County APCD Draft Staff Report for Amended Rule 361. Boilers, Steam Generators, and Process Heaters (Between 2–5 MMBtu/hr); Amended Rule 342. Boilers, Steam Generators, and Process Heaters (5 MMBtu/hr and greater), April 22, 2019, p. 5, *available at*: https://www.ourair.org/wp-content/uploads/2019-05cac-r361-r342-att1.pdf [hereinafter referred to as "Santa Barbara County APCD 2019 Draft Staff Report"].

There are several emerging combustion technologies that demonstrate the potential for even lower levels of NOx without the use of post-combustion controls, such as SCR:

- SOLEX™ Burner is an emerging technology designed to achieve 5 ppm NOx.[553] This burner technology is available as a burner-only alternative to SCR for units "with heat releases between 1 MMBtu/hr and +20 MMBtu/hr."[554] It can be retrofit to existing units and fits traditional ULNB footprints.

- ClearSign Ultra Low NO_x Technology is designed to achieve sub 5 ppm NOx.[555] This technology is reportedly less costly than traditional ultra-low NOx controls with no FGR, lower fuel use, and can be retrofit to existing units. This technology has been installed on several units in SJVAPCD with more testing / demonstration needed:
    - Installation at two refinery heaters (burning natural gas, not refinery gas):
        - 15 MMBtu/hr heater
        - 8 MMBtu/hr heater
    - Installation at two natural gas-fired 62.5 MMBtu/hr oil field steam generators
    - Installation at six enclosed flares (thermal oxidizers)

- Altex Technology Corporation Near Zero NOx Burner has been applied to an 8 MMBtu/hr unit and is capable of achieving 5 ppm under some operating conditions.[556] This technology is being developed as an alternative to SCR for meeting NOx limits as low as 5 ppm for smaller units (e.g., in response to SCAQMD's consideration of a 5 ppm NOx limit for units ≥2 MMBtu/hr).[557]

1. COST EFFECTIVENESS EVALUATIONS FOR COMBUSTION MODIFICATION RETROFITS, REPLACEMENTS, AND UPGRADES

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.[558] In its 1991 guidance CARB determined the cost effectiveness of LNB (in 1986$) for units as small as 3.5 MMBtu/hr and as large as 150 MMBtu/hr, as follows: (1) $500–$6,400/ton for units operating at a 50% capacity factor; and (2) $300–$4,000/ton for units operating at a 90% capacity factor.[559]

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. Based on a review of the various California Air

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[553] John Zink Hamworthy Combustion, SOLEX™ Burner, *see:* https://www.johnzinkhamworthy.com/wp-content/uploads/solex-burner.pdf.
[554] *Id.*
[555] ClearSign https://clearsign.com/. Also see SJVAPCD presentation "ClearSign Ultra Low NOx Technology" November 7-8, 2017, *available at:* https://ww3.arb.ca.gov/enf/training/sympo/ppt2017/0830-b-scandura.pdf.
[556] California Energy Commission Report, *Near Zero NOx Burner*, July 2018, *available at:* https://ww2.energy.ca.gov/2018publications/CEC-500-2018-016/CEC-500-2018-016.pdf.
[557] *Id.*
[558] CARB 1991 Guidance.
[559] CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

District rules and in researching vendor information, the source category of boilers and heaters should be subcategorized into three categories for assessing cost effectiveness and achievable NOx emission rates with combustion modifications: (1) Units > 20 MMBtu/hr (achieving NOx levels as low as 6 ppm); (2) Units >5 MMBtu/hr and ≤20 MMBtu/hr (achieving NOx levels as low as 6 ppm); and (3) Units ≤5 MMBtu/hr (achieving NOx levels of 9–20 ppm). Below, we evaluate cost effectiveness of combustion controls for each of these categories of boilers and heaters, based on cost analyses that local air agencies have relied on for regulating these units.

a) Units >20 MMBtu/hr

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 $PM_{2.5}$ Attainment Plan commitments to reduce NOx emissions.[560] SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm.[561] As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with ULNB to achieve a NOx level of 6 ppm, based on vendor cost data. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with ULNB includes detailed direct and indirect capital and operating costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr.[562] For the larger size units (>20 MMBtu/hr), SJVAPCD notes that the retrofit may involve "upgrades to various systems such as fuel train to comply with up to date codes, and may involve upgrades to air intake fans, as these units require more air for the burner to operate at its optimum level."[563]

Table 36 below summarizes the total costs for retrofitting existing units >20 MMBtu/hr with ULNB, based on SJVAPCD vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life. Low NOx technologies should last the life of the emission unit. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.[564] And a review of the emission units in New Mexico permitted oil and gas sources such as gas processing plants show average ages of boilers and heaters of 30-35 years. Thus, we used a 25-year life as a minimum life for a heater or boiler controls in the cost effectiveness analysis, which seems more than justified. Table 36 presents the cost effectiveness of applying these low NOx technologies to existing units to reduce NOx emissions from uncontrolled levels to 6 ppm. Uncontrolled emissions are based on the EPA AP-42 uncontrolled

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[560] SJVAPCD Rules 4306 and 4320. *See*: https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE.

[561] SJVAPCD 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards (November 15, 2018), Appendix C: Stationary Source Control Measure Analysis at C-94, *available at:* http://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/C.pdf [hereinafter referred to as "SJVAPCD 2018 $PM_{2.5}$ Attainment Plan"].

[562] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

[563] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-81.

[564] *See, e.g.,* SCAQMD Presentation for Rule 1109.1 – NO_x Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12.

emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 36. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[565]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
30	$261,813	$19,518	$3,270	$1,817
40			$2,452	$1,362
50			$1,962	$1,090
60			$1,635	$908
70			$1,401	$779
80			$1,226	$681
90			$1,090	$606
100			$981	$545

Based on this analysis of SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

SJVAPCD provides separate cost data for oilfield steam generators, noting that most of these units would be 62.5 MMBtu/hr.[566] The SJVAPCD analysis notes that, "[a]s many steam generators are one off built units, they may have different firebox configurations that may not accept the new burner without varying degrees of modification."[567] However, SJVAPCD analyzed retrofitting these units with new burner technology to achieve a NOx level as low as 5 ppm, based on vendor data. Using this same vendor cost data, the cost effectiveness of retrofitting a 62.5 MMBtu/hr unit to reduce NOx levels to 5 ppm ranges from $1,664/ton to $6,656/ton, depending on the extent of the modifications or upgrades that are needed.[568]

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[565] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.
[566] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-83.
[567] *Id.*
[568] This range of cost effectiveness is based on retrofit cost data of $450,000–$1,800,000 and assumes an 80% capacity factor from SJVAPCD's analysis. Annualized costs are calculated assuming a 25-year life and a 5.5% interest rate.

b) Units >5 and ≤20 MMBtu/hr

We also completed a cost effectiveness analysis of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB based on SJVAPCD vendor cost data for units of this size.[569] Table 37 presents the cost effectiveness of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB to reduce NOx emissions to 6 ppm from uncontrolled levels based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 37. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[570]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
5	$69,816	$5,205	$5,232	$2,906
10			$2,616	$1,453
15			$1,744	$969
20			$1,308	$727

Based on this analysis using SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >5 and ≤20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

c) Units ≤5 MMBtu/hr

SMAQMD, in a cost effectiveness analysis for its most recent revision of its rules (in 2005) for boilers and heaters ≥1 MMBtu/hr, noted that, for units ≥1 MMBtu/hr and <5 MMBtu/hr, "[s]ome of these units may not be retrofitted because of equipment age and design and will have to be replaced with new units."[571]

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[569] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-81–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

[570] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

[571] Sacramento Metropolitan AQMD Staff Report Rules 411 and 301, October 27, 2005, p. 10, *available at:* http://www.airquality.org/ProgramCoordination/Documents/Rules411and301%20StaffReport%20102705%20Item11.pdf [hereinafter referred to as "SMAQMD 2005 Rule 411 Staff Report"].

The SMAQMD cost data included the costs for replacing existing units with new units equipped with "low NOx technologies" in order to meet the District's emission limits, including costs for equipment, installation, permitting, and source testing for unit sizes ranging from 1–100 MMBtu/hr.[572] Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Thus, it is assumed that it is more cost effective to replace units that are of a size less than or equal to 5 MMBtu/hr with new units equipped with state-of-the-art combustion controls for NOx.

Table 38 below summarizes cost data for replacing units ≤5 MMBtu/hr with new units with "low NOx technologies." The costs include costs for equipment, installation, permitting, and source testing, along with calculated annualized costs of the control, and assume a 5.5% interest rate and a 30-year life of the new unit.[573] These low NOx technologies should last the life of the emission unit, and Colorado assumed a 30–40 year life for heater-treater units of this size based on manufacturer data.[574] We used a 30-year life as a minimum useful life for replacement heater or boiler controls in the cost effectiveness analysis, which is justified.

Table 38. Total and Annualized Costs of Replacement of Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies.[575]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2005$)	TOTAL ANNUALIZED COSTS (2005$)
1	$36,284	$2,551
2	$52,284	$3,652
3	$72,284	$5,028
4	$80,284	$5,579
5	$135,567	$9,328

For the units of 5 MMBtu/hr and lower, SMAQMD's Rule 411 establishes a NOx limit of 30 ppm, but there have been improvements in low NOx technologies demonstrating that units in this size range can meet NOx limits of 20 ppm and even as low as 9 ppm for some applications, based on a review of vendor information.[576] Several California Air Districts require units >2 and <5 to meet a limit of 7–12 MMBtu/hr and units ≤2 MMBtu/hr to meet a limit of 20 ppm. For example, SCAQMD Rule 1146.1 requires units >2 and <5 MMBtu/hr meet limits between 7–12 ppm, depending on the type of unit. And SJVAPCD Rule 4307 requires units >2 and ≤5 MMBtu/hr meet limits of 9 ppm (non-atmospheric units) and 12 ppm

572 SMAQMD 2005 Rule 411 Staff Report Attachment D-1.
573 SMAQMD 2005 Rule 411 Staff Report Attachment D-2.
574 CDPHE RP for Heater-Treaters at 5.
575 Cost data provided by boiler manufacturers to SMAQMD, annualized costs calculated assuming a 30-year life and a 5.5% interest rate.
576 *See, e.g.,* Parker Industrial Boiler, offering units <5 MMBtu/hr with Low NOx Power Burners for NOx levels to 9 ppm. *Available at*: https://www.parkerboiler.com/products/.

(atmospheric units). SCAQMD Rule 1146.2 requires units ≤2 MMBtu/hr be manufactured to meet a NOx limit of 20 ppm and SCAQMD provides a list of numerous units that are pre-certified to meet this limit.[577] SJVAPCD also requires point-of-sale NOx limits for units ≤2 MMBtu/hr of 20 ppm.[578] And VCAPCD's Rule 74.15.1 currently requires new and replacement units ≥1 and ≤2 MMBtu/hr to also meet a 20 ppm NOx limit.[579] See Table 42 for a complete and more detailed list of state and local rules, including many with limits for units in this size range of 9–20 ppm.

While the costs of NOx combustion control technologies to meet NOx limits as low as 9 ppm may be higher than what SMAQMD assumed in its 2005 cost analysis, it is also likely that the costs of low NOx combustion controls have not changed much since then. This is because as air pollution controls are required to be implemented more frequently over time, the cost of the air pollution control often decreases due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. For example, SCAQMD concluded from its 2008 cost analysis that, "[t]he capital cost for retrofitting a unit has decreased by about 70%...."[580]

Therefore, we calculated the cost effectiveness of retrofitting these size units with low NOx technologies using these cost data based on two emission control scenarios: (1) meeting the SMAQMD limit of 30 ppm; and (2) meeting limits achievable today with low NOx combustion technology.

Table 39 below summarizes the cost effectiveness of replacing existing units ≤5 MMBtu/hr with new units with low NOx technologies, based on SMAQMD cost data shown above in Table 38. Table 39 below presents the cost effectiveness of replacement units with low NOx technologies to reduce NOx emissions from the uncontrolled emission rate based on EPA for units >2 MMBtu/hr and the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr) for units ≤2 MMBtu/hr. The SCAQMD-average unit emission rate was, "derived by the SCAQMD to calculate the baseline emissions for this [size] category."[581] This rate, "accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep."[582] Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. For the second scenario, the analysis assumes units >2 and ≤5 MMBtu/hr meet a NOx limit of 9 ppm and units ≤2 MMBtu/hr meet a NOx limit of 20 ppm. Meeting emission limits of 9 ppm and 20 ppm from the estimated uncontrolled levels reflect a control efficiency of 89% and 82%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

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[577] *See* http://www.riteboiler.com/docs/Rite-Low-NOx-SCAQMD-Precertified-Boilers.pdf.
[578] SJVAPCD Rule 4308. *Available at:* https://www.valleyair.org/rules/currntrules/03-4308_CleanRule.pdf.
[579] VCAPCD Rule 74.15.1. *Available at:* http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf.
[580] SCAQMD 2018 Draft Staff Report at 4-3. Note, while SCAQMD's analysis specifically applies to retrofitting units ≥20 and <75 MMBtu/hr with ULNB it's also possible that these changes in cost would apply to units of other sizes, as well.
[581] SJVAPCD 2009 Final Draft Staff Report for Rule 4308.
[582] *Id.*

Table 39. Cost Effectiveness of Replacing Existing Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies Operating at a 50% and 90% Capacity Factor.[583]

UNIT SIZE (MMBtu/hr)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)
1	$12,160	$6,756	$10,809	$6,005
2	$8,703	$4,835	$7,736	$4,298
3	$12,322	$6,846	$8,771	$4,873
4	$10,254	$5,696	$7,298	$4,055
5	$13,715	$7,619	$9,762	$5,423

For the smallest units, San Joaquin Valley APCD (SJVAPCD) analyzed the cost of reducing NOx emissions for its point-of-sale rule for boilers and process heaters sized 0.075 to less than 2 MMBtu/hr. Table 40 below shows the differential capital costs (i.e., the difference in cost between a compliant and non-compliant unit), the annualized costs re-calculated using on a 5.5% interest rate (in place of the 10% interest rate assumed by SJVAPCD), and the cost of NOx reduction based on a current unit average emission rate of 110 ppmv meeting a limit of 20 ppmv. For units ≤2 MMBtu/hr uncontrolled emissions are estimated based on the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr). Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Cost data were provided to SJVAPCD by stakeholders, retailers, and manufacturers. And again, we used a 30-year life as a minimum life for replacing unit controls with low NOx technologies in the cost effectiveness analysis, as previously discussed. SJVAPCD used a 22% capacity factor in its analysis based on survey data collected by SCAQMD and Bay Area AQMD for "typical usages for these units," which presumably reflect a wide range of application and do not necessarily reflect how these size units are used in oil and gas applications, where heaters can operate continuously.

[583] Cost data provided by boiler manufacturers to SMAQMD (2005$), annualized costs calculated assuming a 30-year life and a 5.5% interest rate.

Table 40. Cost Effectiveness Based on Differential Costs to Reduce NOx Emissions from Replacing Units with Units with Low-NOx Burner Technology to Meet a NOx Limit of 20 ppm, Operating at 22% Capacity[584]

UNIT SIZE (MMBtu/hr)	DIFFERENTIAL CAPITAL COST (2009$)	ANNUALIZED COST (2009$)	COST EFFECTIVENESS (2009$)
0.75	$100	$8	$883/ton
0.4	$750	$63	$1,242/ton
2.0	$3,000	$251	$994/ton

For units operating at a higher capacity factor, as would likely be the case for many of the units used in the oil and gas production and processing segments, the cost per ton of NOx removal of choosing to replace a unit with a new unit with low NOx technologies over a higher-emitting unit would be even less than what is shown in Table 40. For these type of smaller units, SCAQMD Rule 1146.2 requires units with rated capacities between 400,000 and 2,000,000 Btu/hr (i.e., 0.04 and 2 MMBtu/hr) and more than 15 years old, depending on the original manufacturer date, to meet the same emission standards as new units.[585] Meeting these standards, according to SCAQMD, requires the retrofit, or more likely, replacement of the older units.[586]

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the heater-treater source category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[587] In its evaluation, Colorado reported that:

> The Four Corners Air Quality Task Force considered low NOx burners as a mitigation option for the Four Corners area and had the following finding: "Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction." It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-NO_X burners are not commercially available for very small combustion sources such as heater-treaters.[588]

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[584] *See* SJVAPCD 2009 Final Draft Staff Report for Rule 4308. Annualized costs of control were calculated using a capital recovery factor of 0.068805 (assuming a 30-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJAPCD's assumed unit average emission rate of 110 ppmv meeting an emission limit of 20 ppmv.

[585] SCAQMD Rule 1146.2, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17.

[586] *See* SMAQMD 2010 Rule 414 Staff Report at 13 (describing SCAQMD rules).

[587] CDPHE RP for Heater-Treaters.

[588] *Id.* at 3.

The Four Corners Air Quality Task Force report was from 2007 and there have been great improvements since then in low NOx technologies. As shown throughout this section on combustion modifications, however, units around 2 MMBtu/hr, and even smaller, are available with low NOx technologies that can meet very low NOx emission limits and can even, in some cases, be retrofitted with these technologies to achieve emissions reductions from existing units. Note, Colorado's RP for Heater-Treaters indicates that a typical heater-treater design rate is about half of the 5 MMBtu/hr threshold for exemptions from Colorado's permitting requirements.[589] And beyond these very small units, low NOx technologies are widely available and generally cost effective for units ≥5 MMBtu/hr.

2. LOWERING COMBUSTION TEMPERATURES TO REDUCE NOx EMISSIONS

Colorado also considered lowering heater-treater temperatures to reduce NOx emissions and described this combustion modification approach, as follows:

> This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: "...heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions."[590]

Estimates for NOx emission reductions from lowering heater-treater temperatures were not provided in EPA's Gas STAR analysis and were not assessed by Colorado. Capital costs were estimated at $1,000–$10,000 and annual operating and maintenance costs were estimated to range from $100–$1,000.[591] Colorado anticipated that there would be no additional time needed for achieving compliance with this technology, that the lowered heater-treater temperature would reduce fuel use, and that there would be no non-air quality impacts. Further, Colorado concluded that this control technology would not affect the service life of the heater-treater, noting that the typical life of a heater-treater is 30 to 40 years.[592]

There are few energy and non-air environmental impacts of combustion modifications for heaters and boilers. Generally, the combustion practices used to reduce NOx emissions also increase thermal efficiencies by reducing the amount of excess air needed for combustion, which has the added benefit

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[589] *Id.* at 5.
[590] *Id.* at 2.
[591] *See* EPA Partner Reported Opportunities (PRO) Fact Sheet No. 906 (last updated September 2004), *available at:* https://www.globalmethane.org/documents/m2mtool/docs/lowerheatertreatertemp.pdf and CDPHE RP for Heater-Treaters at 3.
[592] CDPHE RP for Heater-Treaters at 4.

of reducing fuel usage and increasing energy savings. According to EPA, "[r]eductions in NOx formation achieved by reducing flame temperature and oxygen levels can increase CO and HC emissions if NOx reductions by combustion controls are taken to extremes."[593] And systems where blowers or fans are used, e.g., for LNB plus FGR, will require additional electric energy.

According to EPA, the length of time to install ULNB is 6–8 months (excluding permitting, reporting preparation, and programmatic and administrative considerations).[594]

While the cost estimates in this section on combustion modification are of a cost basis that spans a timeframe from 1986–2018, it is important to note that, beginning in 2006, several state and local air agencies adopted rules to lower NOx emission limits of 30 ppmv to as low as 5–12 ppm for larger units and found it was cost effective to require such a level of control on existing boilers and heating units. This will be discussed further in Section F. below. It is not possible to accurately escalate the older costs to more current dollars. EPA cautions against escalating costs over a period longer than five years because it can lead to inaccuracies in price estimation.[595] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. In some cases, the cost of the air pollution control decreases over time due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.[596] In any event, the fact that air agencies have found low NOx combustion technologies to be cost effective to meet NOx emission limits in the range of 5 to 30 ppm indicates that similar sources have had to incur the costs reflected in Tables 36-40 to meet reduced NOx emission limits, and thus the costs of low NOx combustion technology should be considered reasonable for most heaters and boilers.

B. POST-COMBUSTION CONTROLS: SCR AND SNCR

Post-combustion controls, such as SCR and SNCR, reduce NOx formation in the flue gas. The following is EPA's description of these add-on control techniques:

> These techniques control NOx by using a reactant that reduces NOx to nitrogen (N2) and water. The reactant, ammonia (NH3) or urea for SNCR, and NH3 for SCR, is injected into the flue gas stream. Temperature and residence time are the primary factors that influence the reduction reaction. Selective catalytic reduction uses a catalyst to facilitate the reaction.[597]

[593] EPA 1993 ACT for Process Heaters Section 2.4.
[594] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
[595] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[596] For example, SCAQMD concluded from its 2008 cost analysis that, "[t]he capital cost for retrofitting a unit has decreased by about 70%...." (SCAQMD 2018 Draft Staff Report at 4-3).
[597] EPA 1993 ACT for Process Heaters at 2-6.

SCR systems on natural gas-fired boilers and heaters should be able to achieve NOx removal efficiencies in the range of 80 to 90+%.[598] SNCR systems on natural gas-fired industrial boilers and heaters can achieve NOx reductions in the range of 30-75%.[599]

As early as 1991, CARB, in its 1991 RACT / BARCT determination for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, identified SCR and SNCR as two of four control methods (along with FGR and LNB).[600] CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input), a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would "need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems."[601]

EPA provided cost effectiveness data for SNCR at model heaters in its 1993 Alternative Control Techniques document. Specifically, cost effectiveness of SNCR for heaters, at the time, ranged from: (1) \$3,200–\$6,700/ton for a 77 MMBtu/hr heater; (2) \$2,700–\$5,700/ton for a 121 MMBtu/hr heater; and (3) \$2,300–\$4,900/ton for 186 MMBtu/hr heater.[602]

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.[603] In its 1991 guidance, CARB determined the cost effectiveness of SNCR (in 1986\$) for units as small as 50 MMBtu/hr and as large as 375 MMBtu/hr, as follows: (1) \$1,500–\$6,000/ton for units operating at a 50% capacity factor; and (2) \$1,300–\$3,800/ton for units operating at a 90% capacity factor.[604]

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. A recent analysis by California's SCAQMD for revisions to its series of rules for boilers and process heaters (i.e., Rules 1146, 1146.1, and 1146.2) concluded that, "[u]pon reviewing the type of pollution control technologies available to control NOx emissions applicable to the boilers, steam generators and process heaters subject to Rule 1146 and 1146.1, SCR and ultra-low NOx burners are still the main technologies that can achieve the NOx concentration limits specified in these rules."[605] SCAQMD further determined that, "[b]ased on the 2008 staff reports for Rule 1146 and 1146.1, SCR as applied to Rule 1146 boilers can achieve NOx

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598 *See* Petroleum Refinery Tier 2 BACT Analysis Report, Prepared for EPA by Eastern Research Group, Inc., January 16, 2001, at 3-11, available at: https://archive.epa.gov/airquality/ttnnsr01/web/pdf/bactrpt.pdf. *See* also NESCAUM 2000 Status Report at II-7. These are both cited by EPA in its Chapter 2, Selective Catalytic Reduction, June 2019, in Section 4 of EPA's Control Cost Manual (References 19 and 24)

599 *See* EPA, Control Cost Manual, Section 4, Chapter 1, Selective Noncatalytic Reduction, at 1-2, *available at:* https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf.

600 CARB 1991 Guidance at 8.

601 CARB 1991 Guidance at 6.

602 EPA 1993 ACT for Process Heaters Table 2-4. EPA calculates an annualized cost of control assuming a capital recovery factor of 0.131474 (i.e., assuming a 15-year life of controls and a 10% interest rate).

603 CARB 1991 Guidance.

604 CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

605 SCAQMD 2018 Draft Staff Report at 2-4.

concentrations from 5 to 6 ppm for units greater than or equal to 75 MMBtu/hr."[606] SCAQMD's revisions to Rule 1146 for Boilers, steam generators, and process heaters ≥5 MMBtu/hr allow facilities until January 1, 2022 to retrofit all existing units and until January 1, 2023 to replace any existing units to meet a NOx emission limit of 5 ppm for units ≥75 MMBtu/hr burning natural gas.[607] SCAQMD determined that the 1146 rule series are cost effective, including for units ≥75 MMBtu/hr retrofitted with SCR to meet an emission limit of 5 ppm.[608]

In the SJVAPCD, the District described the following approach to achieving lower NOx limits, acknowledging certain technical and cost feasibility considerations with SCR for certain units:

> The amendment of Rule 4306 in October 2008 was initially proposed to lower the NOx emission limit from 9 ppmv to 6 ppmv for units greater than 20 MMBtu/hr. It was determined that the proposed NOx limits could be accomplished by using selective catalytic reduction (SCR) or a combination of SCR and ultra-low NOx burners (ULNBs), thus making the lower limits technologically feasible. However, through the public workshop process and additional research it was also determined that most of the units subject to Rule 4306 have undergone several generations of NOx controls, and consequently, certain applications of SCR may not be cost effective and/or technological infeasible because of physical limitations. Therefore, the lower NOx limits were included in new Rule 4320 and an option was provided in the rule that allows for the payment of an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through District incentive programs, the District's Technology Advancement Program, and other routes.[609]

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 $PM_{2.5}$ Attainment Plan commitments to reduce NOx emissions.[610] SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm.[611] As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with SCR to achieve these NOx levels, based on information from SCR vendors. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with SCR includes detailed direct and indirect capital, installation, and operating and maintenance costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr.[612]

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606 *Id.* at 2-2.
607 *Id.* at 1-2.
608 *Id.* at 4-6.
609 *See* SJVAPCD 2016 Plan for the 2008 8-Hour Ozone Standard (June 16, 2016), p. C-27, *available at:* http://www.valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/c.pdf.
610 SJVAPCD Rules 4306 and 4320. *See*: https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE.
611 SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-84–C-87.
612 SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

Table 41 below summarizes the total costs for retrofitting existing units ≥5 MMBtu/hr with SCR, based on SJCAPCD-obtained vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life for SCR. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.[613] Table 41 also presents the cost effectiveness of applying SCR existing units to reduce NOx emissions from uncontrolled levels to levels of: (1) 2.5 ppm for units >20 MMBtu/hr; and (2) 3.5 ppm for units >5 and ≤20 MMBtu/hr.[614] Uncontrolled emissions are based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting emission limits of 2.5 ppm and 3.5 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art SCR technology of 96% and 97%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 41. Cost Effectiveness of Retrofitting Existing Units with SCR to Achieve NOx Levels of 2.5 ppm for Units >20 MMBtu/hr and 3.5 ppm for Units >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[615]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
5	$261,728	$26,055	$25,354	$14,086
10			$12,677	$7,043
15			$8,451	$4,695
20			$6,339	$3,521
30	$385,705	$38,397	$6,149	$3,416
40			$4,612	$2,562
50			$3,689	$2,050
60			$3,074	$1,708
70			$2,635	$1,464
80			$2,306	$1,281
90			$2,050	$1,139
100			$1,845	$1,025

613 *See, e.g.,* SCAQMD Presentation for Rule 1109.1 – NO_x Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12.

614 *See* SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-85 and C-87, stating: "Source test results of various units with SCR systems indicate that an SCR can potentially achieve 3.5 ppmv NOx @ 3% O2 for units rated between 5 to 20 MMBtu/hr." and "Source test results of various units with SCR system indicate that an SCR can reliably achieve 2.5 ppmv NOx @ 3% O2 (or less) emissions for units greater than 20 MMBtu/hr."

615 Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

SJVAPCD based its cost analysis on vendor data for the SCR systems and largely on EPA's Air Pollution Control Cost Manual (6th Edition) for installation, operating and maintenance costs, etc., for these systems.

This analysis indicates that it is cost effective to retrofit units, especially those >20 MMBtu/hr, with SCR to achieve NOx levels as low as 2.5–3.5 ppm.

The energy and non-air environmental impacts of post-combustion control techniques include:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) in order to maintain output across the catalyst;
- Solid waste disposal of spent SCR catalyst;
- Ammonia, CO, and nitrous oxide emissions with the use of SNCR;
- Ammonia and sulfite emissions with the use of SCR; and
- Ammonia handling and storage with SNCR and SCR.[616]

According to EPA, the length of time to install SCR is 28–58 weeks (excluding permitting, reporting preparation, and programmatic and administrative considerations).[617] The Institute of Clean Air Companies has stated that SCRs for smaller units (less than 20,000 standard cubic feet per minute gas throughput) are often available in ready-to-install SCR skid packages, and thus SCR for smaller units would take closer to 28 weeks to install.[618] An SNCR would take much less time to install. The Institute of Clean Air Companies states that it takes about 10-13 months to install SNCR, which covers the time from bid evaluations to startup of the SNCR.[619]

C. NOx CONTROLS FOR SEPARATORS

Colorado's Reasonable Progress Evaluation for the heater-treater source category evaluated the installation of insulation on the separator to reduce fuel usage, and resulting combustion emissions (including NOx).[620] Installation of insulation on separators was also included in the Four Corners Air Quality Task Force Report of Mitigation Options for the oil and gas industry and determined to be a technically feasible technique for reducing NOx emissions.[621] Estimates for NOx emission reductions from insulating separators were not provided in the Four Corners Air Quality Task Force report and were not assessed by Colorado. The cost effectiveness of this control will depend on the remaining life of the

[616] EPA 1993 ACT for Process Heaters Section 2.4.
[617] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
[618] *See* Institute of Clean Air Companies, Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006, at 4-5, *available at:* https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[619] *Id.* at 7-8.
[620] CDPHE RP for Heater-Treaters.
[621] Four Corners Air Quality Task Force Report of Mitigation Options (November 1, 2007) at 89.

equipment to which it is applied. Colorado anticipated that there would be no additional time needed for achieving compliance with this technology and that there would be no non-air quality impacts.

D. NOx CONTROLS FOR DEHYDRATORS

Use of a zero emission dehydrator can significantly reduce fuel requirements for a reboiler and therefore reduce combustion emissions (including NOx). The Four Corners Air Quality Task Force report identified this type of dehydrator as a mitigation option and described this type of unit and its emissions, as follows:

> The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. . . . Benefits of this technology include: . . . Reduces emissions of particulate matter, sulfur dioxide, NOx or CO emissions . . . Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.[622]

The Four Corners Air Quality Task Force report describes how existing dehydrators can be retrofitted to zero emissions dehydrators, "by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs."[623] The Four Corners Air Quality Task Force reports that operating and maintenance costs are lower than for conventional glycol dehydrators and further reports that EPA estimates the payback for installing a zero emission dehydrator in place of a conventional glycol dehydrator to occur in less than a year.[624]

E. CENTRAL GATHERING FACILITIES TO REDUCE NOx EMISSIONS FROM WELLHEAD SEPARATION SOURCES

Centralization of gas well gathering facilities can be employed to reduce and consolidate wellsite sources, including heaters and separators. Colorado's Reasonable Progress Evaluation for the heater-treater source category evaluated central gathering facilities to remove wellhead separation.[625] With centralization, emissions from heater-treaters would be reduced because fewer heater-treaters would be needed. Colorado described the effectiveness of this restructuring, as follows:

> Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate

[622] *Id.* at 92.
[623] *Id.* at 93. The report further notes that the electricity needs require a "fuel or power source, for which associated emissions need to be quantified."
[624] *Id.* at 93.
[625] CDPHE RP for Heater-Treaters.

> tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.[626]

Colorado acknowledges that it would be most cost effective to implement a centralized gathering facility on a new field but indicates that retrofitting a field already set up with infrastructure for wellhead separation would be site-specific and depends on several considerations, including the number of heater-treaters being removed, topography, gas composition, mineral rights, etc. Additional benefits of a centralized gathering facility include reduced truck traffic to wellheads (which can be significant sources of fugitive PM emissions) and a reduction in condensate and water tanks (and their associated fugitive emissions). States should consider requiring or otherwise advocating for centralized gathering facilities for new oil and gas development as a measure to prevent future visibility impairment.

Estimates for NOx emission reductions from the centralization of gas well gathering facilities were not assessed by Colorado other than saying that overall emissions will be reduced. Colorado anticipated that additional time needed for achieving centralization would be site-specific, e.g., depending on gas well density and topographical barriers. Finally, Colorado notes that central gathering facilities would be more efficient to operate, reducing overall energy impacts.

F. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR HEATERS AND BOILERS

States and local air agencies have adopted NOx limits for existing boilers and heaters, many of which have been in place for more than 20 years and many of which have been strengthened over the years. In Table 42 below, we summarize some of those state and local air pollution requirements. Primarily, a review of California Air District rules was done for this report, because several of those air districts have adopted the most stringent NOx emission limitations.

Table 42 is a summary of the NOx emission limits required of existing boilers and heaters in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing units and generally required an air pollution control retrofit. These NOx limits were most likely adopted to address nonattainment issues with the ozone and $PM_{2.5}$ NAAQS. Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that governments have adopted NOx limitations that require low NOx technologies at boilers and heaters as small as 0.4 MMBtu/hr and SCR for units ≥75 MMBtu/hr. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD and SJVAPCD. SJVAPCD has a more stringent limit than SCAQMD rules for units between 20 and 75 MMBtu/hr (7 ppm in SJVUAPCD Rule 4320 vs. 9 ppm in SCAQMD Rule 1146), however, it is important to note that for SJVUAPCD's Rules 4306 and 4320, the owner or operator has the option of paying into an annual emissions fee in lieu of

[626] *Id.* at 3.

complying with these limits. For units ≥ 75 MMBtu/hr, the emission limit in SCAQMD Rule 1146 of 5 ppm is more stringent than SJVAPCD's limit of 7 ppm.

Table 42. State/Local Air Agency Natural Gas-Fired Boiler and Heater Rules[627]

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA–SCAQMD	Rule 1146.[628] Adopted 9/9/98 Last revised 12/7/18	≥5 MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		≥5 MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		≥75 MMBtu/hr Effective 1/1/13 Excluding thermal fluid heaters	5 ppm (0.0062 lb/MMBtu)
		≥20 and <75 MMBtu/hr Effective 12/7/18 Excluding thermal fluid heaters, certain fire-tube boilers, and units with a previous NOx limit ≤12 and >5 ppm prior to 12/7/18	5 ppm (0.0062 lb/MMBtu)
		≥5 and <20 MMBtu/hr Effective 1/1/15 (or later for units with a previous NOx limit ≤12 ppm prior to 9/5/08) Excluding atmospheric units and thermal fluid heaters	9 ppm (0.011 lb/MMBtu)
		≥5 and <20 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with a previous NOx limit ≤12 and >9 ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		≥5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)

[627] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules applicable to the types of units found in the oil and gas industry, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.
[628] https://ww3.arb.ca.gov/drdb/sc/curhtml/r1146.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA–SCAQMD	Rule 1146.1[629] Adopted 10/5/90 Last revised 12/7/18	>2 and <5 MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 (or later for units with a previous NOx limit ≤12 and >9 ppm prior to 9/5/08) Excluding atmospheric units, thermal fluid heaters, and certain fire-tube boilers	9 ppm (0.011 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with ≤12 and >9 ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)
CA–SCAQMD	Rule 1146.2[630] Adopted 1/9/98 Last revised 12/7/18	>0.4 and ≤2 MMBtu/hr Effective 1/1/10 Units manufactured or offered for sale	20 ppm (0.024 lb/MMBtu)
		>1 and ≤2 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured on or after 1/1/92, except for units at a RECLAIM or former RECLAIM facility	30 ppm (0.037 lb/MMBtu)
		>0.4 and ≤1 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured prior to 1/1/00, except for units at a	30 ppm (0.037 lb/MMBtu)

629 http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-1.pdf.
630 http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		RECLAIM or former RECLAIM facility	
CA–SJVAPCD	Rule 4320[631] Adopted 10/16/08	>5 and ≤20 MMBtu/hr Effective 1/1/14 Except for certain other units[632]	6 ppmv (0.007 lb/MMBtu)[633]
		>20 MMBtu/hr Effective 1/1/14[634] Except for refinery units,[635] and certain other units[636]	5 ppmv (0.0062 lb/MMBtu)[637]
		>5 MMBtu/hr Effective at the next unit replacement but no later than 1/1/14 Certain units[638]	9 ppmv (0.011 lb/MMBtu)
CA–SJVAPCD	Rule 4306 (Phase 3)[639]	>5 and ≤20 MMBtu/hr	9 ppmv (0.011 lb/MMBtu)

[631] https://www.valleyair.org/rules/currntrules/r4320.pdf.
[632] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.
[633] Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.
[634] The rule allows for a "Staged Enhanced Schedule" for oil field steam generators and refinery units as follows: (1) Initial Limit of 9 ppmv (0.011 lb/MMBtu), effective 7/1/12; and (2) Final Limit of 5 ppmv (0.0062 lb/MMBtu), effective 1/1/14.
[635] Note, refinery unit requirements are the same except that these units have a Standard Schedule limit of 6 ppm, effective 7/1/11.
[636] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.
[637] Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.
[638] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.
[639] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4306.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 9/18/03 Last revised 10/16/08	Effective 12/1/08 Except for oil field steam generators, refinery units, and certain other units[640]	
		>20 MMBtu/hr Effective 1/1/14 Except for oil field steam generators, refinery units, and certain other units[641]	6 ppmv (0.007 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Oilfield steam generators Load-following units[642]	15 ppm (0.036 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Certain other units[643]	30 ppm (0.036 lb/MMBtu)
CA–SJVAPCD	Rule 4307[644] Adopted 12/15/05 Last revised 4/21/16	>2 and ≤5 MMBtu/hr Existing units	30 ppm (0.036 lb/MMBtu)
		>2 and ≤5 MMBtu/hr New or replacement units Effective 1/1/16 Atmospheric units Non-atmospheric units	 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–SJVAPCD	Rule 4308[645] Adopted 10/20/05 Last revised 11/14/13	>0.4 and <2 MMBtu/hr Effective 1/1/15 Point-of-sale[646] PUC gas Non-PUC gas	 20 ppm (0.024 lb/MMBtu) 30 ppm (0.036 lb/MMBtu)
CA–SMAQMD	Rule 411[647]	Effective 10/27/09	

[640] These certain other units include: (1) load-following units; (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.
[641] *Id*.
[642] Load-following units must meet a limit of 9 ppm under the Enhanced Schedule, with a compliance date of 12/1/08.
[643] These certain other units include: (1) refinery units >5 and ≤65 MMBtu/hr (note that units >65 and ≤110 MMBtu/hr are required to meet a limit of 25 ppm (0.031 lb/MMBtu and units >110 MMBtu/hr are required to meet a limit of 5 ppm); (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.
[644] https://www.valleyair.org/rules/currntrules/Rule4307.pdf.
[645] https://www.valleyair.org/rules/currntrules/03-4308_CleanRule.pdf.
[646] This point-of-sale rule covers units supplied, sold, offered for sale, installed, or solicited for installation.
[647] http://www.airquality.org/ProgramCoordination/Documents/rule411.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 2/2/95 Last revised 8/23/07	New and existing units ≥1 and <5 MMBtu/hr ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	 30 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–SMAQMD	Rule 414[648] Adopted 8/1/96 Last revised 10/25/18	>0.4 and <1 MMBtu/hr Effective 10/25/18 (date of last revision) Point-of-sale[649]	20 ppm (0.024 lb/MMBtu)
CA–VCAPCD	Rule 74.15.1[650] Adopted 5/11/93 Last revised 6/23/15	≥1 and <5 MMBtu/hr Effective 1/1/16 Existing units New and Replacement: Atmospheric units Pressurized Units	 30 ppm (0.036 lb/MMBtu) 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 361[651] Adopted 1/17/08 Last revised 6/20/19	>2 and <5 MMBtu/hr Existing units Installed and modified (after 1/1/20): Atmospheric units Non-atmospheric Units	 30 ppm (0.036 lb/MMBtu) 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 342[652] Adopted 3/10/92 Last revised 6/20/19	≥5 MMBtu/hr Existing units Installed and modified (after 1/1/20): ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	 30 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu) 7 ppm (0.0085 lb/MMBtu)
CA–Feather River AQMD	Rule 3.23[653] Adopted 10/3/16	>0.4 and <1 MMBtu/hr Effective 1/1/17 Point-of-sale[654]	20 ppm (0.024 lb/MMBtu)
CA–Bay Area AQMD	Regulation 9 Rule 7[655] Adopted 9/16/92	>2 and ≤5 MMBtu/hr Effective 1/1/15	30 ppm (0.036 lb/MMBtu)

[648] http://www.airquality.org/ProgramCoordination/Documents/rule414.pdf.
[649] This point-of-sale rule covers units manufactured, distributed, offered for sale, sold, or installed.
[650] http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf.
[651] https://www.ourair.org/wp-content/uploads/rule361.pdf.
[652] https://www.ourair.org/wp-content/uploads/rule342.pdf.
[653] https://ww3.arb.ca.gov/drdb/fr/curhtml/r3-23.pdf.
[654] This point-of-sale rule covers units offered for sale, sold, or installed.
[655] https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-7-nitrogen-oxides-and-carbon-monoxide-from-industrial-institutional-and-commercial-boiler/documents/rg0907.pdf?la=en.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		>5 and <10 MMBtu/hr Effective 1/1/15 ≥10 and <20 MMBtu/hr Effective 1/1/14 ≥20 and <75 MMBtu/hr Effective 1/1/14 ≥75 MMBtu/hr Effective 1/1/14 Excluding thermal fluid heaters	15 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu) 5 ppm (0.0062 lb/MMBtu)
TX- Houston-Galveston-Brazoria Area	30 TAC 117.2010(c)(1) Emission Specs for 8hr ozone demo[656]	Emission specs for mass emission cap and trade	0.036 lb/MMBtu (or, alternatively 30 ppm @ 3% O2)
TX	30 TAC 117.3205(a) [657]	Statewide Point-of-sale[658] Effective 7/1/02 >0.4 and ≤2 MMBtu/hr	30 ppm or 0.037 lb/MMBtu
MA	310 CMR 7.26(30)[659]	≥10 and <40 MMBtu/hr Effective 9/14/01	0.0350 lb/MMBtu
NY	6 CRR-NY 227-2.4[660]	>25 and ≤100 MMBtu/hr	0.05 lb/MMBtu
GA	Rule 391-3-1-.02.(2)(III)1.[661]	Effective 5/1/00 Fuel-burning equipment 45 county area – ozone May 1 – September 30 each year	30 ppm

[656]https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.

[657]https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=3205.

[658] Applies to units sold, distributed, installed, or offered for sale.

[659] https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download.

[660] RACT for major sources of NOx: https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).

[661] http://rules.sos.ga.gov/gac/391-3-1.

Most stringent NOx Limits of State/Local Rules:

5 ppm (0.0062 lb/MMBtu)……………………………………………………………………………Units ≥75 MMBtu/hr
5–12 ppm (0.0062–0.015 lb/MMBtu) ………………………………………………… Units >2 and <75 MMBtu/hr
20 ppm (0.024 lb/MMBtu)………………………………………………………………………….. Units ≤2 MMBtu/hr

As Table 42 shows, several state and local air pollution control agencies have adopted NOx emission limits for boilers and heaters that reflect the application of low NOx burner technologies, and reflect SCR for units ≥75 MMBtu/hr. These air agencies have thus found that the levels of NOx control listed in Table 42, including NOx limits as low as 5 ppm for larger units, in the range of 5–12 ppm for smaller units, and as low as 20 ppm for very small units, providing relevant examples for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. The fact that these limits could apply to modified units >2 MMBtu/hr means that the states consider retrofit controls to meet the emission limits in Table 42 above to be cost effective, and should also consider the cost effectiveness of retrofitting units >5 MMBtu/hr to meet NOx limits as low as 2–3.5 ppm based on the work being done in the SJVAPCD.

G. SUMMARY – NO_x CONTROLS FOR NATURAL GAS-FIRED HEATERS AND BOILERS

The above analyses and rule data demonstrate that numerous state and local air agencies have found that low NOx burner technology is a cost effective retrofit NOx control for boilers and heaters >5 MMBtu/hr with costs ranging from $545/ton to $5,232/ton. Smaller units ≤5 MMBtu/hr can be replaced with new units with low NOx burner technology at costs ranging from $4,055/ton to $10,809/ton. Low NOx burner technologies can generally meet limits down to 5–6 ppm, with the potential for emerging technologies to meet NOx levels lower than 5 ppm. For most units, including atmospheric units, a blower may be required to mix the fuel and air prior to combustion. It is possible to reach NOx levels of 9 ppm for non-atmospheric units and 12 ppm for atmospheric units without the use of FGR.[662]

Further, SJVAPCD has found that SCR is cost effective for larger units with costs ranging from $1,025/ton to $6,149/ton to meet NOx levels as low as 2.5 ppm. For the lowest NOx limit of 5–6 ppm currently applicable to units under rules adopted by SCAQMD and SJVAPCD, SCR is presumably necessary to meet these limits.

As states evaluate regulation of NOx emissions from boilers and heaters, there are several factors to consider, such as draft type (i.e., atmospheric vs. non-atmospheric), operating capacity factor, and size. Nonetheless, given the numerous local NOx limits in Table 42 above that reflect operation of low NOx burner technology, and SCR for larger units, these controls for units of all sizes should generally be considered as cost effective measures available to make reasonable progress from boilers, reboilers, and

[662] *See, e.g.,* Santa Barbara County APCD 2019 Draft Staff Report.

heaters, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements.

VIII. ADDRESSING VISIBILITY-IMPAIRING EMISSIONS FROM FLARING AND THERMAL INCINERATION OF EXCESS GAS AND WASTE GAS

Gas flaring is a process to combust excess or waste gases from oil wells, gas processing plants, or oil refineries. Flaring is intended as a means of disposal of excess gas as a safety measure and is also done to relieve pressure in gas pipelines. Combustion of excess or waste gas can also be accomplished with thermal incinerators rather than flaring.[663] Combustion of excess gas whether done through flaring or thermal incineration is also a VOC control device, as the combustion of the gas destroys most of the VOCs. However, the extent to which VOC emissions are effectively destroyed depends on the design and operation of the combustion device.

There are several processes associated with oil and gas development in which excess gas is flared or combusted, including the following: during testing of a new oil or gas well, when natural gas co-occurs with a new oil well, at gas pipeline headers and at gas processing plants when needed to relieve pressure, at gas compressor stations to combust vapors captured by a dehydrator unit, at gas processing plants and at oil refineries when an upset occurs or to allow maintenance of equipment, and at gas sweetening plants.[664]

A flare system is a thermal oxidation process using an open flame. It consists of an elevated flare stack through which the waste or excess gas stream flows, where it is combusted at the tip of the stack producing a flame. This is sometimes referred to as a "candlestick" flare. A thermal incinerator, which is also called a direct flame incinerator, thermal oxidizer, or an afterburner, is a thermal oxidation process that occurs in an enclosed combustion chamber. The temperature of the waste gas is raised in the combustion chamber in the presence of oxygen above its autoignition point by passing the gas through a flame which is maintained by the waste gas and auxiliary fuel, and combustion of the waste gas occurs. More specific descriptions of these control devices are provided below. The purpose of both a flare and a thermal incinerator is to combust the excess or waste gas and reduce VOC emissions.

A. FLARING SYSTEM

EPA describes a flare system as follows:

> Flaring is a high-temperature oxidation process used to burn waste gases containing combustible components such as volatile organic compounds (VOCs), natural gas (or

[663] *See* Alberta Energy Regulator, EnerFAQS, Flaring and Incineration, *available at:* https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring.

[664] *See,* e.g., Ohio EPA, Understanding the Basics of Gas Flaring, November 2014, *available at*: https://www.epa.state.oh.us/portals/27/oil%20and%20gas/basics%20of%20gas%20flaring.pdf. *See also* Eman, Eman A., Gas Flaring in Industry: An Overview, Petroleum & Coal 57(5) 532-555, 2015, *available at:* http://large.stanford.edu/courses/2016/ph240/miller1/docs/emam.pdf.

> methane), carbon monoxide (CO), and hydrogen (H_2). The waste gases are piped to a remote, usually elevated location, and burned in an open flame in ambient air using a specially designed burner tip, auxiliary fuel, and, in some cases, assist gases like steam or air to promote mixing for nearly complete (e.g., ≥ 98%) destruction of the combustible components in the waste gas. Note that destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound (such as carbon dioxide [CO_2], carbon monoxide, or another hydrocarbon intermediate), while combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO_2 and water vapor. . . .
>
> Combustion requires three ingredients: fuel, an oxidizing agent (typically oxygen in the air), and heat (or ignition source). Flares typically operate with pilot flames to provide the ignition sources, and they use ambient air as the oxidizing agent. The waste gases to be flared typically provide the fuel necessary for combustion. Combustible gases generally have an upper and lower flammability limit. The upper flammability limit (UFL) is the highest concentration of a gas in air that is capable of burning. Above this flammability limit, the fuel is too rich to burn. The lower flammability limit (LFL) is the lowest concentration of the gas in air that is capable of burning. Below the LFL, the fuel is too lean to burn. Between the UFL and the UFL, combustion can occur. Completeness of combustion in a flare is governed by flame temperature, residence time and flammability of the gas in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all hydrocarbons and CO are converted to CO_2 and water. Incomplete combustion results in some hydrocarbons or CO discharged to the flare being unaltered or converted to other organic compounds such as aldehydes or acids.[665]

Flares, if operated in a manner to provide for complete combustion, are intended to destroy hydrocarbons and VOCs. Flaring also converts methane to CO_2. Both are greenhouse gases, but methane is a more powerful greenhouse gas.[666] EPA indicates that properly operated flares should achieve 98% destruction efficiency of VOCs.[667] However, according to EPA studies, flares "can operate at a wide range of Destruction and Removal Efficiency (DRE)." As a result, although flares are a VOC control device, flares are also a source of VOC emissions especially when not designed or operated in a manner to achieve high levels of DRE. Further, "[s]mall amounts of uncombusted vent gas will escape the flare combustion zone along with products of incomplete combustion,"[668] which can add to VOC emissions as well as methane emitted from the flare. Flaring of natural gas also results in emissions of NOx, as well as particulate matter emissions of carbon particles (soot) and unburned hydrocarbons.

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[665] EPA, VOC Destruction Controls, Chapter 1 Flares, August 2019, at 1-1, *available at:* https://www.epa.gov/sites/production/files/2019-08/documents/flarescostmanualchapter7thedition_august2019vff.pdf.
[666] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why
[667] *See* EPA, Air Pollution Control Fact Sheet, Flare, EPA-452/F-03-019, *available at:* https://www3.epa.gov/ttn/catc/dir1/fflare.pdf.
[668] Shah, Tejas, Ramboll Environ (EPA Contractor), Greg Yarwood (Ramboll Environ), Alison Eyth (EPA), and Madeleine Strum (EPA), Composition of Organic Gas Emissions from Flaring Natural Gas, August 18, 2017, at 6, *available at:* https://www.epa.gov/sites/production/files/2017-11/documents/organic_gas.pdf.

Flaring is also a significant cause of SO_2 emissions when sour gas or acid gas is flared. Although the sulfur content for gas to be considered sour gas can vary by state, gas with a hydrogen sulfide (H_2S) content of 5.7 milligrams per cubic meter of gas (about 4 ppm) is generally considered to be sour gas.[669] Among other places in the United States, sour gas exists in areas of New Mexico, Texas, Wyoming, and North Dakota.

In terms of air pollution control measures to apply directly to flare design and operation, controls and techniques to ensure or improve DRE are the primary pollution control for natural gas flares. These are discussed further below in Section E.

B. THERMAL INCINERATION

Thermal incineration of gases is generally able to result in more complete combustion due to the greatly improved ability to control fuel and air flow, temperature, turbulence, and residence time.[670] Thus, incineration of excess gases may result in greater destruction of hydrocarbons and lower VOC emissions than if the same amount of gas was flared. As with flaring, while thermal incineration is a VOC control technology, the incineration of waste gas does result in emissions of NOx and some particulate matter as a result of incomplete combustion, along with CO_2. Further, when sour gas or acid gas is combusted in a thermal incinerator, SO_2 will be emitted. In the absence of SO_2 pollution controls, incineration of waste or excess gases may not be the best choice compared to flaring for gas with sulfur compounds, because the elevated height of the flare can allow for greater dispersion of the SO_2 emissions.[671] On the other hand, use of a thermal incinerator to combust excess or waste gas allows for the addition of an acid gas scrubber to remove SO_2 and also could allow for use of the thermal heat produced by the waste gas combustion, whereas those opportunities for SO_2 control and for getting some energy benefit from the combustion of waste gases do not exist with a flare. Further, low NOx combustion controls exist for thermal incinerators. The pollution controls to apply directly to thermal incinerators are discussed further below in Section F.

The best method to reduce/eliminate air emissions from flaring or incineration of excess or waste gas is to avoid the need for combustion of the gases altogether. The options for doing so are discussed further below in Section D.

C. SO_2 EMISSIONS FROM THE DESTRUCTION OF SOUR GAS WASTE STREAMS

For sour gas, the sulfur compounds must be removed to produce pipeline quality natural gas. H_2S is the sulfur compound of most concern in sour gas because the majority of sulfur compounds in sour gas are in the form of H_2S and because it is it is very poisonous, explosive and corrosive. According to the Occupational Safety and Health Administration (OSHA), exposure to H_2S can cause significant eye and respiratory irritation and exposure to high concentrations of H_2S "can cause shock, convulsions, inability

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[669] http://naturalgas.org/naturalgas/processing-ng/.

[670] *See*, e.g., EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, *available at:* https://www3.epa.gov/ttnchie1/mkb/documents/fthermal.pdf.

[671] *See* https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring#what.

to breathe, extremely rapid unconsciousness, coma and death."[672] It is also very corrosive to gas pipelines and can be explosive. Thus, H_2S has to be removed from sour gas streams before the gas can be sent into gas pipelines to consumers. H_2S is removed from the gas in gas sweetening plants, usually via an amine process which separates the H_2S and also CO_2 from the natural gas.[673] Since 1985, the EPA's NSPS have required gas sweetening plants with a capacity of more than 2 long tons per day of H_2S in the acid gas to either 1) completely reinject the acid gas stream into oil- or gas-bearing geologic strata or 2) to use a sulfur reduction and removal technology to reduce SO_2 emissions from the acid gas before it is flared or combusted.[674] Sweetening plants that aren't subject to such requirements may be allowed to flare the acid gas stream or incinerate the gas stream, either of which could release very significant quantities of SO_2 emissions, although it is not clear that any such plants continue to operate. However, even for gas sweetening plants required to control the H_2S by reinjecting into the geologic strata or by using a sulfur recovery unit or other control method, SO_2 emissions from flaring or from thermal incineration is of significant concern. For those plants, flaring episodes occur due to malfunctions or due to maintenance or possibly for other reasons.[675] When flared or combusted, the H_2S in the acid gas stream converts to SO_2, which is a significant visibility-impairing pollutant. EPA states that "100 tons or more of SO_2 can be released in [a flaring episode] within a 24-hour period."[676] In the case of flaring of acid gas streams, the only methods to reduce SO_2 emissions directly from flaring acid gas streams at gas sweetening plants are to reduce or eliminate flaring episodes. Methods to reduce such flaring episodes are discussed in the next section.

D. CONTROL MEASURES, TECHNIQUES, AND OPERATING PRACTICES TO PREVENT FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Prevention of flaring/incineration of excess or waste gases is the best method to reduce the air emissions from this source category. It will also prevent NOx, particulate matter, air toxic emissions including formaldehyde, and CO_2 emissions, as well as any VOCs and methane that are not destroyed in the combustion process. Available methods and techniques to reduce flaring or thermal combustion of excess or waste gas are discussed below.

1. REDUCING FLARING AT THE WELL SITE

In 2016, the U.S. Bureau of Land Management (BLM) issued a rule intended "to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production on onshore Federal and Indian (other than Osage Tribe) leases."[677] This rule is often referred to as the "BLM Waste Prevention Rule."

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[672] OHSA Fact Sheet, Hydrogen Sulfide (H_2S), *available at:* https://www.osha.gov/OshDoc/data_Hurricane_Facts/hydrogen_sulfide_fact.pdf.
[673] *See*, e.g., http://operoenergy.com/gas-sweetening-technologies/.
[674] *See* 40 C.F.R. Subparts LLL and OOOO.
[675] *See* EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, *available at:* https://www.epa.gov/sites/production/files/documents/flaring.pdf.
[676] *Id.*
[677] 81 Fed. Reg. 83,008 (Nov. 18, 2016).

The fact sheet issued by EPA at the time of the rulemaking stated that the rule would phase in, over several years, a flaring limit per development oil well that ratcheted down over time.[678] There were several options for complying with the flaring limits, including: "expanding gas-capture infrastructure (e.g., installing compressors to increase pipeline capacity, or connecting wells to existing infrastructure through gathering lines); adopting alternative on-site capture technologies (e.g., compressing the natural gas or stripping out natural gas liquids and trucking the product to a gas processing plant); or temporarily slowing production at a well to minimize losses until capture infrastructure is installed."[679] The rule also required operators to evaluate opportunities for gas capture before drilling a development oil well, which were to be submitted with an Application for a Permit to Drill and which were to be shared with midstream gas capture companies "to facilitate timely pipeline development. . . ."[680] In 2018, the BLM rescinded the gas capture requirements of the 2016 rule "in favor of an approach that relies on State and tribal regulations and reinstates the NTL-4A standard for flaring in the absence of State or tribal regulations."[681] The 2018 BLM rulemaking describes the NTL-4A standard as the BLM's existing policy from before the 2016 BLM Waste Prevention Rule, which was published in the Federal Register in 1979 (44 Fed. Reg. 76600, Dec. 27, 1979)[682] and "governed venting and flaring from BLM-administered leases for more than 35 years."[683] The BLM has clearly indicated that states could regulate flaring. Indeed, development of the BLM Waste Prevention Rule considered "analogous state requirements related to waste of oil and gas resources," and the BLM "reviewed requirements from Alaska, California, Colorado, Montana, North Dakota, Ohio, Pennsylvania, Utah, and Wyoming."[684] Further, EPA has been requiring the capture and collection of excess gas from the drilling of natural gas wells under the NSPS since 2012.[685]

Thus, there are example state and federal rules[686] and methods that states should adopt, if not already in place, to reduce flaring of gas associated with oil wells, that would not only reduce visibility-impairing pollution from flaring, but that would also reduce air toxics and greenhouse gases emissions as well as ensure that the natural gas produced along with oil at oil wells is utilized as an energy source rather than just flared or combusted to destroy the VOCs.

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[678] *See* BLM Fact Sheet on Methane and Waste Prevention Rule, at 3, *available at:* https://www.doi.gov/sites/doi.gov/files/uploads/methane_waste_prevention_rule_factsheet_final.pdf.
[679] *Id. See also* Clean Air Task Force's publication entitled "Putting Out the Fire: Reducing Flaring in Tight Oil Fields," April 2, 2015, for additional discussion of additional alternatives to flaring excess gas, *available at:* https://www.catf.us/resource/putting-out-the-fire/; and U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and *see* Impacts, June 2019, at 50-55 *available at:* https://www.energy.gov/sites/prod/files/2019/08/f65/Natural%20Gas%20Flaring%20and%20Venting%20Report.pdf.
[680] *Id.*
[681] 83 Fed. Reg. 49,184 at 49,188 (Sept. 28, 2018).
[682] 83 Fed. Reg. 49,184 at 49,185 (Sept. 28, 2018).
[683] 83 Fed. Reg. 49,189 at 49,185 (Sept. 28, 2018).
[684] 81 Fed. Reg. 83,008 at 83,019 (Nov. 18, 2016).
[685] 40 C.F.R. Part 60, Subpart OOOO, §60.5375.
[686] The U.S. Department of Energy has a recent report that summarizes the state and federal rules on flaring. *See* U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts, June 2019, at 20-48.

2. REDUCING FLARING AT COMPRESSOR STATIONS, GAS PROCESSING PLANTS, AND GAS SWEETENING PLANTS

As discussed above, flaring at compressor stations and gas processing plants including gas sweetening plants, is often due primarily to plant upsets and maintenance. Flaring of sour gas or acid gas streams at gas sweetening plants can be a significant source of visibility-impairing SO_2, and thus reducing flaring emissions at gas sweetening plants could be an effective reasonable progress measure to address regional haze. Reducing flaring will also reduce the NOx, PM, VOCs, and CO_2 emitted from the flares.

EPA listed the following measure to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at natural gas compressor stations and at gas processing facilities:

> Conduct a root-cause analysis of each flaring incident to identify if any equipment and/or operational changes are necessary to eliminate or minimize that cause so as to reduce or avoid future flaring events. As appropriate, corrective measures should be taken and implemented. If the analysis shows that the same cause has happened before, the incident should not be considered a malfunction and corrective measures should be taken to prevent future occurrences….[687]

In addition, it is imperative to ensure that there is adequate gas handling capacity at the various processing points in a compressor station, gas processing or gas sweetening plant. EPA states that "[r]edundant units can prevent flaring by allowing one unit to operate if the other needs to be shut down for maintenance or an upset. . . ."[688] Thus, adding excess capacity and/or backup units could be very important in reducing the amount of flaring due to upsets.

As part of their evaluation of measures to provide for reasonable progress towards the national visibility goal, states should evaluate the flaring episodes at the compressor station and at gas processing plants, including the collection of data on the length of time of each flaring episode, frequency, and causes. For plants that have more frequent flaring episodes, and especially for those plants flaring sour gas or acid gas streams from a gas sweetening plant, states should evaluate the root causes of upsets that cause flaring episodes to determine if measures, such as improved maintenance or duplicative parts or processing units, can be employed to reduce flaring episodes.

E. POLLUTION CONTROL TECHNIQUES FOR FLARES

EPA has described the control techniques for flares, based on the federal requirements in EPA's New Source Performance Standards (NSPS) (at 40 C.F.R. §60.8) and EPA's National Emission Standards for Hazardous Air Pollutants (NESHAPs) (at 40 C.F.R. §63.11) as follows:

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[687] *See* EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, at 3 *available at:* https://www.epa.gov/sites/production/files/documents/flaring.pdf.

[687] 81 Fed. Reg. 83,008 (Nov. 18, 2016).

[688] *Id.*

> At a minimum, these [NSPS and NESHAP] rules require flares to be:
>
> - Designed and operated with no visible emissions using EPA [test] Method 22 (except for periods not to exceed 5 minutes in 2 hours);
> - Operated with a flame present at all times, confirmed by the use of a thermocouple or equivalent device;
> - Used only when the net heating value of the gas to be combusted is 300 BTU per standard cubic foot (BTU/scf) or greater (if the flare is steam- or air-assisted), or 200 BTU/scf or greater (if the flare is nonassisted); and
> - Designed for and operated with an exit velocity less than 60 feet per second (f/sec). An exit velocity of greater than 60 ft/sec but less than 400 ft/sec may be used if the net heating value of the gas being combusted is sufficiently high.[689]

Other requirements that must be met include that the flare must be operated at all times in a manner consistent with good air pollution control practices for minimizing emissions, and that flaring operations must be monitored to ensure they are operated and maintained according to their design.[690] EPA has listed several other more detailed guidelines to ensure flares are properly operated.[691] Proper training of employees is also an important part of ensuring the flares are properly operated. States must require documentation of each flaring episode to ensure that the flaring regulations of the NSPS and NESHAPs have been complied with, as well as to ensure that adequate records of the amount of gas flared and causes of flaring are maintained and reported.

The above operating standards are required for all flaring. Alternatives to flaring include 1) gas capture to decrease or eliminate flaring as discussed above, or 2) combusting the gas in a thermal incinerator which can provide for greater destruction of VOC emissions. Also, additional air pollution controls can be used at an incinerator, as is discussed below.

F. POLLUTION CONTROL TECHNIQUES FOR THERMAL INCINERATION OF EXCESS OR WASTE GAS

As discussed above, waste gases or excess gas can be disposed of via thermal incineration rather than a flare. EPA describes a thermal incinerator, or a thermal oxidizer, as follows:

> Incineration, or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. These factors provide the basic design parameters for VOC oxidation systems (ICAC, 1999).

[689] *See* EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 1, *available at:* https://www.epa.gov/sites/production/files/documents/flaringviolations.pdf.
[690] *Id.* at 2; see also 40 C.F.R. §63.172(e) and 60.482-10.
[691] *See*, e.g., EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 3.

> A straight thermal incinerator is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger (this type of incinerator is referred to as a recuperative incinerator).
>
> The heart of the thermal incinerator is a nozzle-stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. Upon passing through the flame, the waste gas is heated from its preheated inlet temperature to its ignition temperature. . . The required level of VOC control of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. The nominal residence time of the reacting waste gas in the combustion chamber is defined as the combustion chamber volume divided by the volumetric flow rate of the gas. . . .[692]

EPA indicates that thermal incinerators can achieve 98% to 99.9999% destruction of VOCs.[693] However, thermal incinerators typically require auxiliary fuel to preheat the waste gas and sustain the heat necessary for destruction of VOCs.[694] The high temperature reaction necessary in an incinerator to destroy the VOC and air toxic emissions can result in increased NOx emissions. To limit NOx emissions, low NOx burners or other low NOx processes are available control measures to integrate into the thermal incinerator to limit NOx emissions.[695] Thus, for any thermal incinerators or thermal oxidizers, low NOx burners or other low NOx emission systems should be installed to minimize NOx emissions from the thermal incinerator.

It is important to note that thermal incinerators can be used at gas sweetening plants along with acid gas scrubbers to remove the SO_2 that is formed from combusting the H_2S in the acid gas. Such a system could potentially be used as an SO_2 control,[696] or it could be used as a backup system for a sulfur recovery unit when it is down due to malfunction, maintenance, or during startup or shutdown.[697] This method of control could greatly reduce if not eliminate the SO_2 emissions that occur at gas sweetening

[692] EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 4, *available at:* https://www3.epa.gov/ttnchie1/mkb/documents/fthermal.pdf.
[693] *Id.* at 5.
[694] *Id. See also* EPA, Control Cost Manual, Section 3, Chapter 2 – Incinerators and Oxidizers, at 2-3 to 2-4, *available at:* https://www.epa.gov/sites/production/files/2017-12/documents/oxidizersincinerators_chapter2_7theditionfinal.pdf.
[695] *See*, e.g., Zeeco Products & Applications, Incinerators & Thermal Oxidizers Multi-Stage Low-NOx Incinerator/Thermal Oxidizer, *available at:* https://www.zeeco.com/incinerators/incinerators-therm-ox-multi-stage.php. *See also* AERON, Thermal Oxidation/Incineration Systems, Ultra-Low Emissions Systems, *available at:* http://www.aereon.com/enclosed-combustion-systems/ultra-low-emissions-systems/certified-ultra-low-emissions-burner-ceb.
[696] *See*, e.g., AERON, Thermal Oxidation/Incineration Systems, Tail Gas Incineration Units, which discusses acid flue gas scrubbers as an available option, *available at:* http://www.aereon.com/enclosed-combustion-systems/thermal-oxidationincineration-systems/tail-gas-incineration-units.
[697] *See* Envitech, Industrial Gas Cleaning Systems, Air Pollution Control Innovations, Refinery Sulfur Recovery Unit (SRU) SO_2 Scrubber for Startup, Shutdown, and Malfunctions, *available at:* https://www.envitechinc.com/air-pollution-control-innovations/refinery-sulfur-recovery-unit-sru-so2-scrubber-for-startup-shutdown-and-malfunctiong-post-title-here.

facilities when the gas injection well or sulfur recovery unit is not in operation due to malfunctions or maintenance.

In many respects, combusting of waste gases and/or excess gas in a thermal incinerator seems more preferable from an air pollutant perspective than flaring, because thermal incineration will likely result in a greater destruction efficiency of VOCs and because control options exist for limiting emissions of NOx and of SO_2 (to the extent that sour gas or an acid gas stream is what was being flared). Further, there could be an option of gathering and routing excess gas emission from multiple points to a centralized thermal incinerator. Moreover, continuous emission monitoring systems (CEMS) could be installed in the thermal oxidizer stack to provide valuable actual emissions data due to the combustion of waste or excess gases, including information to ensure that optimal VOC destruction efficiency is achieved.

However, the need for auxiliary fuel in thermal combustion means more CO_2 will be emitted than if the gas stream was flared. Yet, there are options for thermal incinerators that recover the waste heat, which are called recuperative oxidizers or regenerative oxidizers.[698] The recovered waste heat can be used to preheat the incoming air which would reduce the amount of supplemental fuel required.[699]

To sum up, use of a recuperative or regenerative thermal incinerator (thermal oxidizer) with low NOx combustion controls, CEMs, and an acid gas scrubber if necessary, seems to be a preferable alternative to flaring of waste gas streams. Such a system would provide better control of VOCs, reduce NOx emissions from combustion of the waste gas via the use of low NOx combustion controls, and provide the ability to add an acid gas scrubber to remove SO_2 (which is a control option that does not exist for flares).

G. SUMMARY – BEST OPTIONS FOR CONTROLLING EMISSIONS DUE TO FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Based on the above analysis, it seems evident that prevention of flaring through the collection of excess gas is the most beneficial option for reducing emissions from flaring. Capturing and using the natural gas that is produced at oil wells would ensure that the energy value of the gas is not wasted by being combusted in a flare or in an incinerator, and it is very likely that the end user of the gas would at least be using some level of NOx and VOC control.

Thermal incineration should be considered in lieu of flaring for waste gases due to the pollution controls for NOx and SO_2 that are available and because of the improved operation and VOC destruction. Moreover, use of a thermal incinerator provides the opportunity to monitor and accurately track emissions from the combustion of waste or excess gases with the use of CEMS.

At gas processing facilities including gas sweetening plants, it is important that the causes of flaring episodes be documented and assessed to determine any changes in operations, training, and/or in equipment that may be needed to reduce plant upsets and maintenance during which flaring occurs due

[698] EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 5.
[699] *Id.*

to the unavailability of plant equipment to process the gas stream. As stated above, adding excess capacity and/or backup units could be very effective in reducing the amount of flaring due to upsets. Proper maintenance of equipment is also key, as is appropriate training of staff to minimize flaring episodes due to maintenance and upsets.

In general, states should ensure that their rules require companies to document all flaring episodes, including the cause, duration of the flaring, flue gas flow, actions taken to stop the flaring, and emission estimates, and to submit such documentation to the state or local air agency in a timely manner. This data will best enable states to develop appropriate rules and procedures to limit the various causes of flaring emissions within its state.

Overall, the goal of state programs to address flaring emissions should be to minimize flaring to the maximum extent possible. However, for those situations when flaring does occur, it is imperative that the flares be operated in accordance with NSPS and NESHAP requirements, and that the flares are operated and maintained in accordance with their design. Moreover, to ensure these requirements are being met and to ensure that flaring is minimized to the maximum extent possible, the state or local air agencies must conduct thorough oversight into the causes of flaring episodes, to ensure that the facility is being maintained and operated in a manner to minimize all flaring episodes to the extent possible.

United States Department of the Interior

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TRANSMITTED VIA ELECTRONIC MAIL - NO HARDCOPY TO FOLLOW

N3615 (2350)

April 27, 2017

Gary Huitsing, P.E.
Washington Department of Ecology
Air Quality Program
300 Desmond Drive SE
Lacey, WA 98503

Dear Mr. Huitsing:

Tesoro Refining & Marketing Company LLC (Tesoro) is proposing a Clean Products Upgrade Project (CPUP) which would be a major modification at the Anacortes Refinery in Washington. The facility is located 76 km from North Cascades National Park (NP), 77 km from Olympic NP, and 176 km from Mt. Rainier NP, all Class I areas administered by the National Park Service (NPS). The proposed modification is major for particulate matter less than or equal to 10 microns in diameter (PM10) and particulate matter less than or equal to 2.5 microns in diameter (PM2.5) due to a 21.6 ton-per-year (tpy) increase in these pollutants, as well as a 347,644 tpy increase in and Greenhouse gases (GHG). The CPUP also includes several minor modifications emitting other criteria pollutants. The proposed modifications include a new steam boiler, a Marine Vapor Emission Control system, an expansion of the Naphtha Hydrotreater and an Aromatics Recovery Unit. The project expands the ability of the Anacortes refinery to deliver cleaner local transportation fuels and global feedstocks for polyester production but does not increase the refinery's capacity to process crude or change the crude slate processed.

We reviewed Tesoro's April 2016 permit application and associated draft permits from the Washington Department of Ecology and the Northwest Clean Air Agency. We recognize that the Tesoro modification is major for PM10 and GHG, and that Tesoro has employed effective controls to minimize the emissions from the modification. We commend Tesoro for the addition of Selective Catalytic Reduction (SCR) on the new boiler. Tesoro also proposes to collect and combust the displaced vapors from loading marine vessels along with natural gas introduced at the dock safety unit to keep the gas within safe ranges. This project reduces volatile organic compound (VOC) emissions from the facility by over 300 tpy. We appreciate the addition of controls for VOC on the marine loading facility and the reduction in VOC is significant.

NPS Analysis of Impacts on Air Quality Related Values

In our review of the Tesoro Anacortes refinery, our primary concerns are visibility and nitrogen deposition impacts at North Cascades NP and Olympic NP based on current emissions from the entire facility. We modeled 2014 – 2015 average annual emissions from the facility (as described below) to estimate these current impacts.

CALPUFF Model

The NPS air quality impact analysis applied the EPA CALPUFF 5.8 suite of models. (CALPUFF version 5.8 Level 070623, CALMET Level 070623, POSTUTIL Level 070623, and CALPOST Version 6.221.) The modeling was performed in the regulatory mode with the switch MREG=1. The pollutants modeled for both the existing emissions scenario (2014A-annual) and (2015-annual) were SO_2, SO_4, NO_x, elemental carbon, organic carbon, and $PM_{2.5}$ in pounds per hour units. The stack parameters and locations, the CALMET data, and the Class I discrete receptors were all from the major modification modeling analysis Tesoro submitted to the State of Washington's Department of Ecology.

The three years (2003 – 2005) of CALMET used 12 months of MM5 prognostic data, NWS upper air data, and NWS surface stations. The model domain consists of 115 four-kilometer east-west grid cells and 105 north-south four-kilometer grid cells with ten vertical layers. The hourly ozone data used in the modeling were from 38 ozone monitors. These monitors were located in the three national parks being analyzed, 14 ozone monitors sites in Washington, 9 ozone monitors from sites located in Oregon, 4 ozone monitor sites in Idaho, and 7 ozone monitor sites located in British Columbia, Canada. The monthly ammonia (NH_3) background data of 17 ppb) was from a monitoring study conducted in the Frazer Valley, British Columbia, Canada approximately 10 kilometers north of the US-Canada boundary. This historical and conservative ammonia monitoring data has been applied by Washington for many years.

The Anacortes refinery consists of 62 different stacks and sources. Many of the stacks only emit small amounts of air pollutants. Therefore, the NPS air quality impact analysis focused on only the large emitting stacks/sources. NPS grouped the emission points into 7 groups. Group 1: Crude heaters and CGS heaters; Group 2: Vacuum flash heater, Catalytic Cracker heaters, DHT heater, and CFH heater; Group 3: Main Boiler; Group 4: NHT heaters; Group 5: Catalytic Reform heaters; Group 6: CCU Boilers; and Group 7: Small engines and points without stacks. The VOC-only sources were not modeled.

The CALPUFF outputs from the 7-stack scenario were run through the post processor POSTUTIL for both visibility and acid deposition in separate runs. In the POSTUTIL visibility run, the option switch MNITRATE, which recomputes the HNO3/NO3 partition, was set = 1 so as not to overestimate the formation of particulate nitrate.

The visibility impacts were modeled with CALPOST version 6.221 following the methodology found in the Federal Land Managers' Air Quality Related Values Work Group 2010 Phase I Report—Revised (2010 FLAG)[1] using Method 8, Mode 5. This Method incorporates

[1] 2010 FLAG, p. 23. *See* http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf.

background extinction coefficients which are computed from monthly concentrations representative of North Cascades, Olympic, and Mount Rainier NPs for ammonium sulfate (BKSO4), ammonium nitrate (BKNO3), coarse particulates (BKPMC), organic carbon (BKOC), soil (BKSOIL), elemental carbon (BKEC) and sea salt (BKSALT). Monthly Relative Humidity Adjustment Factors for small and large SO_4 and NO_3 and sea salt specific to North Cascades, Olympic, and Mount Rainier NPs from FLAG are also applied.

The visible haze impacts for the present and future emissions scenarios for the 7-stack configuration impacts for North Cascades, Olympic and Mount Rainier NPs are found below. According to the 2010 FLAG, "[i]f this analysis indicates that the 98th percentile values for change in light extinction are equal to or greater than 5% [0.5 deciview] for any year, then the Agencies will further scrutinize the applicant's proposal."

The nitrogen and sulfur deposition impact analyses used the POSTUTIL program which combines both the wet and dry deposition concentrations of the five species modeled (SO_2, SO_4, NO_x, HNO_3, and NO_3) to produce a deposition of both total sulfur and total nitrogen. Nitrogen and sulfur deposition impacts for the present and future emissions scenarios for the 7-stack configuration impacts for North Cascades, Olympic and Mount Rainier NPs are discussed below.

Modeled Impacts from Tesoro (Please see Appendix A for additional details.)

Class I Area	Average 98th % Delta Deciview	Average Number of days with Delta-Deciview => 0.5	% of Modeled Extinction by Species							Deposition kg/ha/yr	
			% SO4	% NO3	% OC	% EC	% PMC	% PMF	% NO2	S	N
OLYM	1.691	61.7	13.1	76.9	3.7	0.0	1.1	1.9	3.3	0.003	0.014
NOCA	0.749	32.0	13.5	74.8	3.5	0.0	1.6	2.6	4.0	0.005	0.078
MORA	0.142	0.0	16.0	76.3	3.8	0.0	0.7	2.3	1.0	0.000	0.001

Olympic National Park

At Olympic National Park, our modeling of annual average emissions predicted that the highest 98th percentile 24-hour visibility impact of 1.917 dv occurred with the 2003 meteorological data[2]; the 2003 through 2005 average of the 98th percentile values was 1.691 deciview (dv), and Tesoro's emissions caused visibility impairment each year. All three years modeled showed at least 53 days with impacts greater than 0.5 dv, with an average of 61.7 days per year. Nitrate was always the dominant species impairing visibility. Nitrogen deposition exceeded our Deposition Analysis Threshold (DAT)[3] each year 2003 through 2005, peaking at 0.016 kg/ha/yr based on 2003 meteorology; the average was 0.014 kg/ha/yr.

[2] NPS modeled the 98th percentile values for 24-hour visibility impact using meteorological data from 2003 -2005
[3] 2010 FLAG p. 66. "A DAT is defined as the additional amount of nitrogen or sulfur deposition within an FLM area, below which estimated impacts from a proposed new or modified source are considered negligible."

North Cascades National Park

At North Cascades National Park, our modeling of annual average emissions predicted that the highest 98th percentile 24-hour visibility impact of 0.779 dv occurred with the 2005 meteorological data[4]; the 2003 through 2005 average of the 98th percentile values was 0.749 dv, and Tesoro's emissions caused or contributed to visibility impairment each year. All three years modeled showed at least 28 days with impacts greater than 0.5 dv, with an average of 32 days per year. Nitrate was always the dominant species impairing visibility. Nitrogen deposition exceeded our DAT each year 2003 through 2005, peaking at 0.192 kg/ha/yr based on 2003 and 2004 meteorology; the average was 0.0781 kg/ha/yr.

Mount Rainier National Park

At Mount Rainier National Park, our modeling of annual average emissions predicted that the highest 98th percentile visibility impact of 0.179 dv occurred with the 2003 meteorological data[5]; the 2003 through 2005 average of the 98th percentile values was 0.142 dv, and Tesoro's emissions did not cause or contribute to visibility impairment any year. All three years modeled showed no impacts greater than 0.5 dv. Nitrate was always the dominant species impairing visibility, but less so than at Olympic or North Cascades. Nitrogen deposition did not exceed our DAT in any year, peaking at 0.0018 kg/ha/yr based on 2005 meteorology; the average was 0.0012 kg/ha/yr.

We understand that, for this modification, the only PSD-applicable pollutants are particulate and GHG. The above modeling was done based on the current (2014 – 2015) annual emissions from the entire facility. The visibility comments provided here do not apply to the currently-proposed modification. However, given the significant visibility impacts of the entire Tesoro facility on North Cascades and Olympic National Parks, we note that the Tesoro refinery should be considered for additional controls during the next Reasonable Progress phase of the Regional Haze Rule.

We would also like to point out that the most significant contributor to the visibility impacts is NOx. For this reason we would also like to commend Tesoro and the Northwest Clean Air Agency on the addition of SCR on the new boiler and the permit limit of 9 ppmdv (corrected to 3% O2).

[4] NPS modeled the 98th percentile values for 24-hour visibility impact using meteorological data from 2003 – 2005.
[5] NPS modeled the 98th percentile values for 24-hour visibility impact using meteorological data from 2003 – 2005.

Thank you again for providing the permit for comment. We look forward to working with both Washington Department of Ecology and Tesoro on future Reasonable Progress activities. If you have questions, please contact Don Shepherd of my staff at don_shepherd@nps.gov or 303-969-2075.

Sincerely,

Susan M. Johnson
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catalysts

MDPI

Review

Strategies of Coping with Deactivation of NH_3-SCR Catalysts Due to Biomass Firing

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Abstract: Firing of biomass can lead to rapid deactivation of the vanadia-based NH_3-SCR catalyst, which reduces NO_x to harmless N_2. The deactivation is mostly due to the high potassium content in biomasses, which results in submicron aerosols containing mostly KCl and K_2SO_4. The main mode of deactivation is neutralization of the catalyst's acid sites. Four ways of dealing with high potassium contents were identified: (1) potassium removal by adsorption, (2) tail-end placement of the SCR unit, (3) coating SCR monoliths with a protective layer, and (4) intrinsically potassium tolerant catalysts. Addition of alumino silicates, often in the form of coal fly ash, is an industrially proven method of removing K aerosols from flue gases. Tail-end placement of the SCR unit was also reported to result in acceptable catalyst stability; however, flue-gas reheating after the flue gas desulfurization is, at present, unavoidable due to the lack of sulfur and water tolerant low temperature catalysts. Coating the shaped catalysts with thin layers of, e.g., MgO or sepiolite reduces the K uptake by hindering the diffusion of K^+ into the catalyst pore system. Intrinsically potassium tolerant catalysts typically contain a high number of acid sites. This can be achieved by, e.g., using zeolites as support, replacing WO_3 with heteropoly acids, and by preparing highly loaded, high surface area, very active V_2O_5/TiO_2 catalyst using a special sol-gel method.

Keywords: biomass firing; NH_3 SCR; potassium resistant catalysts; alumino silicate addition; coal ash; tail end placement; basic coating; KCl; aerosol

1. Introduction

The amount of electricity generated from firing solid biomass has been rising steeply in Europe over the last decades and is expected to continue to do so [1]. Similar trends are seen in other regions of the world [2,3]. Replacing fossil fuels, especially coal, by biomass aims at reducing the CO_2 emissions associated with thermal power plants [2,4–7]. Even though renewable energy sources like solar and wind power are more and more cost competitive [8] and make up an increasing share of power generation in most regions [9], some thermal power plant capacity is still needed due to the renewables' fluctuating nature and the current lack of sufficient storage capacity [10]. Firing and co-firing of biomass can cause several problems in the power plant like slagging and fouling problems in boilers [11], ash deposition on heat exchangers, and increased catalyst deactivation in the NO_x removing unit [12–18]. This review deals with the last-mentioned problem.

NO_x gases cause formation of photochemical smog, acid rain (HNO_3), and ground level ozone formation. These conditions in turn have adverse consequences on human life and ecosystems. NO_x emissions from power plants can be reduced by modifications to the combustion process (primary measures) or post-combustion techniques (secondary measures). Secondary measures are typically more expensive but also afford a higher degree of NO_x removal. Due to ever stricter environmental regulations, secondary measures are increasingly needed for power plants to be compliant. The highest degree of NO_x removal is achieved with selective catalytic reduction (SCR) using ammonia as the reductant [18,19]. The most widespread kind of catalyst is V_2O_5-WO_3/TiO_2 (VWT) [20,21]. The loading of the active species vanadia is typically between 1 and 5 wt.%, depending on the temperature of operation and the SO_2 content in the flue gas. Tungsta adds acid sites, reduces SO_2 oxidation, and reduces rutilization of anatase. The typical loading is between 5 and 10 wt.%.

The increased rate of catalyst deactivation experienced in biomass-fired plants is mostly caused by the relatively high alkali- and alkali-earth metal contents in most biomasses [11,17,20–24]. Alkaline metals cause deactivation by neutralizing the catalyst's acid sites, hence reducing the adsorption of NH_3 [13,25–30]. Potassium, in the form of submicron aerosols of mainly KCl and K_2SO_4 [31–33], is the most important poison due to both its relative abundance and high basicity [24,34]. Equation (1) gives a simplified neutralization reaction with M being any metal.

$$MCl + V - OH \rightarrow HCl + V - M \tag{1}$$

Other modes of deactivation like change in redox properties [35,36] and pore plugging [31] were reported to be of minor importance.

We have identified four kinds of strategies to deal with the high potassium content in biomasses: (1) potassium removal by adsorption; (2) tail-end placement of the SCR unit; (3) alkali barrier materials on the catalyst surface; and (4) intrinsically potassium resistant catalysts.

2. Strategies Coping with Potassium Rich Fuels

2.1. Potassium Removal by Adsorption

One way of reducing the impact of potassium salts is to minimize the amount taken up by the catalyst bed(s). An obvious strategy is to use an acidic guard bed in front of the catalyst modules. However, due to the high space velocities (5000–10,000 h^{-1}) in SCR units and the high KCl content of about 0.2^{-1} g Nm^{-3} of the flue gas [37,38], such a guard bed would probably be saturated too rapidly and require substantial space. Assuming a KCl concentration of 0.2 g Nm^{-3} in the flue gas, a "guard bed space velocity" of 20,000 h^{-1}, and a monolith density of 300 kg m^{-3}, 1 h of exposure translates into about 180 µmol K per gram. Even highly acidic substances like H-type zeolites with low Si/Al ratios only possess around 5000 µmol of acid sites per gram [39]. To the best of our knowledge, no guard beds have been implemented so far.

Wang et al. [24] have published a critical review on additives mitigating ash related problems. They have grouped the additives by the following four capture mechanisms: (1) chemical absorption and reaction; (2) physical absorption; (3) dilution and inert elements enrichment and (4) restraining and powdering effects. The first mentioned mechanism was singled out to be the most effective and is based on converting troublesome ash elements into high temperature stable compounds. Additives causing chemical binding can be based on alumino silicates such as, e.g., kaolin, coal fly ash, cat litter, clay minerals, and detergent zeolites. Alumino silicates bind potassium according to the simplified Equation (2).

$$Al_2O_3{\cdot}xSiO_2 + 2KCl + H_2O \rightarrow K_2O{\cdot}Al_2O_3{\cdot}SiO_2 + 2HCl_{(g)} \tag{2}$$

Addition of fly ash obtained from coal-fired plants is an industrially used strategy [40] to bind potassium. Coal fly-ash contains high levels of alumino silicates, which can bind potassium [14,40,41]. Coal fly-ash has the advantage of being abundant and low-cost. Diarmaid et al. [11] have very recently studied the efficacy of coal-fly ash in reducing the release of potassium from various biomass (white wood pellets, straw, and olive cake) pellets suspended in a methane flame. Additive loadings of 5, 15, and 25 wt.% were used. Olive cake requires larger amounts of alumino silicates to minimize potassium release, probably because it contains more potassium than the other two biomasses. In the presence of additive, up to 100% of K is retained, and in the wood and olive cake ash up to 80% is retained, demonstrating the effectiveness of alumino silicates even when burning pure biomasses with high potassium contents.

Firing coal with up to 10% [42,43] or even 20% [44] of biomass has also been reported to result in acceptable catalyst stability, probably because the resulting coal fly ash adsorbs released potassium compounds.

Sulfates of, e.g., ammonia, iron, aluminum, and phosphates of ammonia and calcium, as well as phosphoric acid, have also been listed by Wang et al. A possible issue with using sulfates is an increased formation of SO_3. Injection of phosphorous-based "K-getter" compounds leads to the formation of, e.g., K_3PO_4 and $K_4P_2O_7$. Dahlin et al. [27] performed a multivariate analysis of six catalyst poisons (Na, K, Mg, P, S, and Zn) by impregnating monolithic VWT catalysts with corresponding metal precursor solutions. The obtained model showed that P dampens the deactivating effect of K and was explained by the formation of phosphates, preventing the interaction of potassium with vanadia. The effect of K_3PO_4 on the stability of a vanadia-based catalyst was investigated by Castellino et al. [45] by exposing full length monoliths to a flue gas containing between 100 mg of K_3PO_4 per Nm^3. 720 h of exposure caused almost 40% deactivation, which was mainly ascribed to potassium neutralizing the catalyst's acid sites and thereby resembling the deactivation by KCl. The authors concluded that binding K by P is not advantageous to the SCR unit.

2.2. Tail-End Placement of the SCR Unit

Wieck-Hansen et al. [15] studied the catalyst stability using a slip stream from a 150 MW coal-straw (80%/20%) fired power plant. The catalyst was exposed to the flue gas at 350 °C without prior de-dusting, simulating high-dust placement, and at 280 °C downstream of a baghouse filter, which reduced the particulate concentration from 100 to a few mg Nm^{-3}, simulating low-dust placement of the SCR unit. 2860 h of high-dust exposure caused about 35% activity loss, while 2350 h of low-dust exposure only caused 15% activity loss. The difference in stability can probably be explained by the removal of, e.g., KCl particles by the dust-filter. Tail-end placement would probably lead to an even higher stability because of the desulphurization unit further reducing the potassium content in the flue gas. Tail-end operation at the biomass co-fired Amager plant in Denmark indeed showed promising results between 2010 and 2012 [44]. Laboratory studies by Putluru et al. [46] have furthermore shown that heteropoly acid (instead of WO_3)-promoted catalysts with a high (3 and 5 wt.%) vanadia loading can retain more than 90% of their activity at 225 °C when poisoned with 100 µmol K $g_{catalyst}^{-1}$. A corresponding WO_3 promoted catalyst lost almost 50% of its activity. At 400 °C, the loss was reported to be around 70% [47]. Generally, potassium poisoning has a stronger relative effect at high temperatures [23,48], which is reflected by a lower apparent activation energy upon potassium poisoning [23], which is consistent with acid neutralization being the main mode of deactivation.

Kristensen et al. [49] reported excellent potassium tolerance and activity of sol-gel prepared 20 wt.% V_2O_5/TiO_2 at temperatures below 250 °C. The potassium loading introduced by KNO_3 impregnation was 280 µmol K $g_{catalyst}^{-1}$. A commercial reference catalyst got completely deactivated.

The major drawback with tail-end placement is that wet and dry SO_2 scrubbers typically reduce the flue gas temperature to about 50 and 150 °C, respectively. The VWT catalyst is not active enough at these temperatures, making costly reheating to 180–280 °C necessary. Over the last 10 to 15 years, a high number of reports on low-temperature SCR catalysts have appeared [50]. The aim of these studies is to make re-heating redundant. However, most of the reported catalysts are based on manganese, making them extremely sulfur and water sensitive. In 2014, we summarized literature findings on the effects of SO_2 and H_2O and could not find any convincing reports on sulfur and water-resistant manganese-based catalysts [51]. Here we only give some examples of reports on catalysts being severely affected by SO_2 and H_2O. Casapu et al. [52] studied $MnCeO_x$ and reported a 79% activity reduction at 150 °C by adding 5 vol.% of water to the simulated flue gas. Flue gases typically contain at least 5 vol.% of water. Exposing the same catalyst to 50 ppm of SO_2 for 30 min at 250 °C reduced the NO conversion from about 70 to 25%. Our group has experienced rapid and severe deactivation of $MnFe/TiO_2$ and $MnFeCe/TiO_2$ at 150 °C by SO_2 levels as low as 5 ppm [51,53]. The modes of deactivation were formation of $(NH_4)_2Mn_2(SO_4)_3$ and ammonium sulfates. Regeneration by heating to 400 °C was only effective with prior washing with base. 20 vol.% of water in the flue gas reduced the NO conversion over a $MnFe/TiO_2$ from over 90% to 30.6%. Doping with ceria did not improve the water tolerance. In 2018, Gao et al. [54] reviewed the sulfur and water tolerance of Mn-based catalysts at low temperature and concluded, among other things, that more long term studies are needed to validate the viability of this kind of catalyst under realistic conditions.

2.3. Coating Monoliths with Basic Substances

In order to reach the catalyst's acid sites, potassium, typically originating from submicron aerosols of KCl and K_2SO_4, first needs to be deposited on the external catalyst (monolith) surface [48]. From there, potassium needs to separate from its counter-ion and diffuse into the catalyst pores, most likely through a surface transport mechanisms involving acid sites [31,55]. In other words, potassium mobility becomes a determining factor in the poisoning mechanism of monolithic samples. A pilot plant study performed by Jensen et al. [48] investigated the potassium uptake and the resulting deactivation of plate type samples with various WO_3 (0, 7 wt.%) and V_2O_5 (1, 3, 6 wt.%) contents. According to ammonia chemisorptions measurements, both tungsta and vanadia add acid sites to the fresh samples, thereby favoring the potassium uptake. This, in turn, leads to an increased rate of deactivation, e.g., 600 h of KCl aerosol (0.12 μm) at 350 °C leads to 76, 81, 89, and 98% relative deactivation for 1%V_2O_5–0% WO_3, 3%V_2O_5–0% WO_3, 1%V_2O_5–7% WO_3, and 3%V_2O_5–7% WO_3, respectively. Based on these results, it is highly questionable if the commonly used strategy of simply increasing the number of surface acid sites is realistic under real life conditions. Despite the just quoted deactivation data, tungsta-free catalysts are not an option for biomass fired plants, because they start from a significantly lower base activity and probably suffer from rutilization over time.

Since the potassium uptake relies on acid sites on the outer monolith surface, it can be reduced by coating this surface with a basic material, thus reducing the relative rate of deactivation [23,56,57]. MgO and Sepiolite ($Mg_4Si_6O_{15}(OH)_2{\cdot}6H_2O$) have been reported as effective barrier materials. These substances are, on the one hand, basic enough to hinder potassium from penetrating the catalyst wall, and, on the other hand, they do not cause deactivation on their own. Olsen et al. [56] coated a plate type catalyst with composition of 3 wt.% V_2O_5–7 wt.% WO_3/TiO_2 with 8.06 wt.% MgO resulting in a roughly 200 μm thick layer and performed a pilot plant exposure campaign with KCl aerosols for several hundred hours at 350 °C. The coating layer reduced the rate of deactivation from 0.91% to 0.24% per day. These percentages refer to the initial activity of the uncoated sample. However, the decreased rate of deactivation comes at the cost of an initial activity reduction of about 42%. This activity reduction was ascribed to increased gas phase diffusion limitations introduced by the MgO layer, slight poisoning by MgO on the outer layer of the catalyst, or a combination thereof. SEM-EDS measurements confirmed that the outer MgO layer very effectively prevented potassium from diffusing into the catalyst and that magnesium did not diffuse into the catalyst. Kristensen [23] very successfully used sepiolite as a binder material for making plate type catalysts from 20 wt.% V_2O_5/TiO_2 powder, reinforced silica sheets, and 20 wt.% sepiolite as binder. The resulting catalyst was exposed to a KCl aerosol for 632 h at 380 °C and thereafter crushed to a powder for lab scale activity measurements. A commercial of 3 wt.% V_2O_5–7 wt.% WO_3/TiO_2 plate type catalyst was used as reference. When tested at 400 °C after KCl exposure, the 20 wt.% V_2O_5/TiO_2-Sepiolite composite retained 68% of its activity, translating into a first order rate constant of about 1650 $cm^3{\cdot}g^{-1}{\cdot}s^{-1}$. The activity loss of the reference catalyst was 84%, and the resulting first order rate constant was reported to be only about 200 $cm^3{\cdot}g^{-1}{\cdot}s^{-1}$. These activity losses were compared with data from a corresponding incipient wetness (KNO_3) poisoning study. The losses experienced by the 20 wt.% V_2O_5/TiO_2-Sepiolite composite and the reference translate into impregnated K loadings of 75 and 172 μmol K $g_{catalyst}^{-1}$, strongly suggesting that sepiolite acts as a barrier material. This was confirmed by SEM-EDS measurements, showing that potassium mainly accumulated on the outer surface of the plate.

2.4. Intrinsically Potassium Resistant Catalysts

In this review "intrinsically potassium resistant" refers to catalysts that retain a high share of their activity, even when potassium is taken up from the flue gas and diffuses into the catalysts pore system. To the best of our knowledge, there is up to now no review on potassium tolerant catalysts.

The majority of studies mimic potassium poisoning by impregnation with potassium salts like e.g., KNO_3, K_2CO_3, and KCl followed by calcination. The resulting K-loaded catalysts are typically tested in powder form in lab scale reactors. Studies performed by different laboratories are often difficult to compare due to vastly different experimental conditions and benchmark catalysts. For example, using different potassium loadings and activity testing in different temperature regimes might lead to different conclusions. Benchmarking against catalyst of different potassium tolerance might also lead to different conclusions. Because of these shortcomings in comparability, we start this section with results from our laboratory, which tested a high number of alternative catalysts using identical or very similar experimental conditions.

Figures 1 and 2 present the potassium tolerance for an assortment of catalyst with various active metals (Fe, Cu, and V) and support materials (TiO_2, tungsto phosphoric acid (TPA) promoted TiO_2, mordernite (MOR), and sulfated ZrO_2). The retained activity clearly depends on the number of acid sites of the fresh catalysts, which in turn is very much a function of the support material.

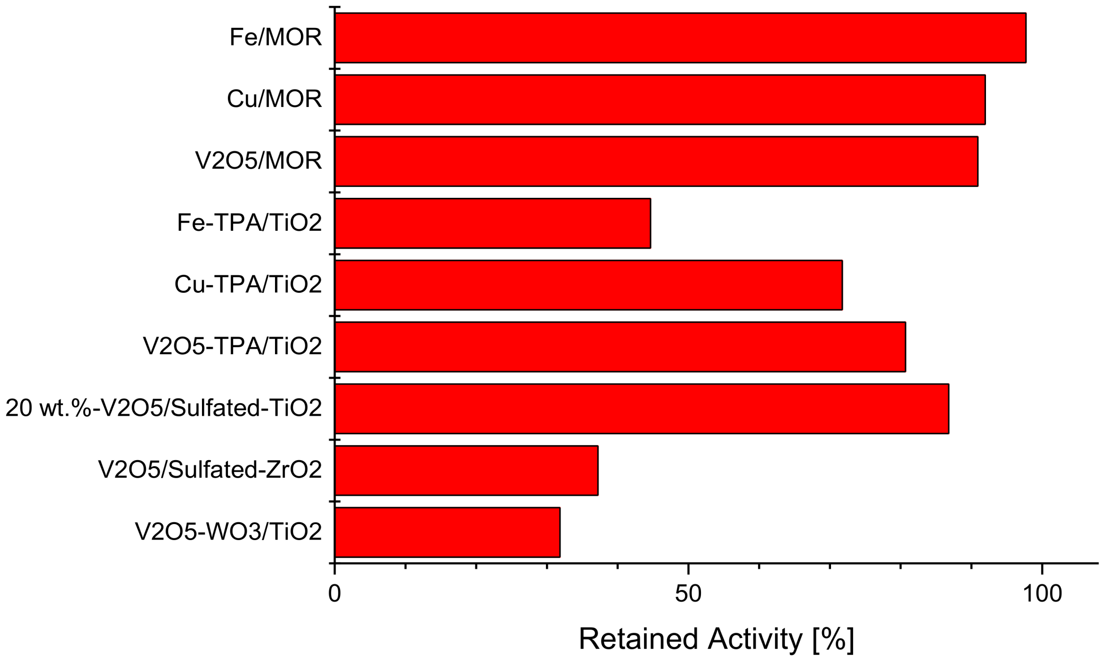

Figure 1. Retained activity at 400 °C upon impregnation with 100 µmol K $g_{catalyst}^{-1}$. (130 µmol K $g_{catalyst}^{-1}$ for V_2O_5/sulfated-ZrO_2). Reproduced from [47].

In this study, the highest alkali tolerance was obtained with MOR (Si/Al = 10)-based catalysts. Putluru et al. [58] optimized the Cu loading and tested the effect of 0, 250, and 500 µmol K/$g_{catalyst}$. 4 wt.% Cu/MOR retains about 60% of its initial activity after poisoning with 500 µmol K $g_{catalyst}^{-1}$, while only half that potassium loading causes more than 80% deactivation on a reference catalyst containing 3 wt.% vanadia and 7 wt.% tungsta. Cu/BEA (Si/Al = 25) and Cu/ZSM5 (Si/Al = 15) exhibit only slightly lower potassium tolerance than Cu/MOR does. Cu/Zeolite catalysts are not only very potassium resistant but also very active at 400 °C with first order rate constants of up to 1800 $cm^3g^{-1}s^{-1}$, while this value is only about 1000 $cm^3g^{-1}s^{-1}$ for the VWT reference catalyst [49]. Since the high potassium tolerance is at least in part due to the high number of acid sites on the zeolites, these materials will probably have to be protected by a thin layer of, e.g., MgO in order to avoid increased uptake of potassium containing particles. Another issue with Cu-based catalyst is their sulfur intolerance [59,60]. Vanadia supported on zeolites are very potassium tolerant but suffer from relative low activities. Likewise, iron-zeolite catalysts show comparatively low activities below 400 °C.

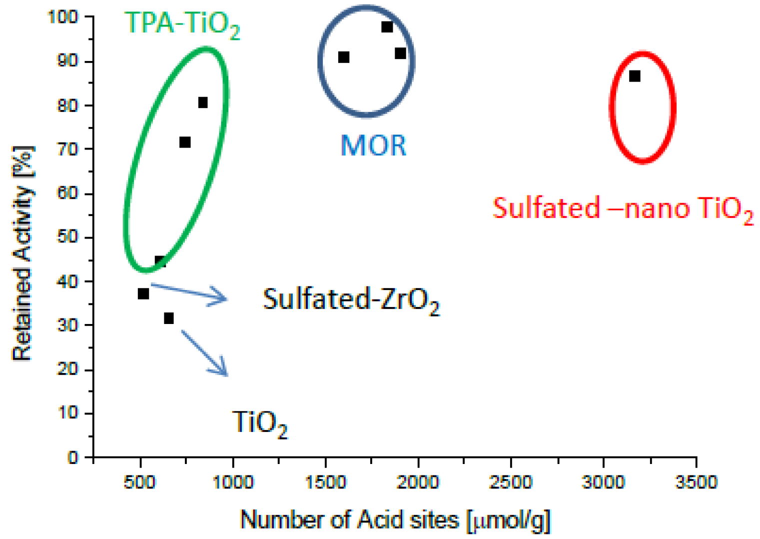

Figure 2. Retained activity at 400 °C upon impregnation with 100 µmol K $g_{catalyst}^{-1}$ (130 µmol K $g_{catalyst}^{-1}$ for V_2O_5/sulfated-ZrO_2) as a function of the number of acid sites of fresh catalysts. Generated with data from [47].

Putluru et al. [61] also demonstrated that the WO_3 component of the VWT catalyst can be replaced by heteropoly acids such as $H_3PW_{12}O_{40}$, $H_4SiW_{12}O_{40}$, $H_3PMo_{12}O_{40}$, and $H_4SiMo_{12}O_{40}$. Heteropoly acids contain more acid sites than WO_3, and these can probably serve as sacrificial sites, which is reflected by a higher potassium tolerance. Tungsto phosphoric acid (TPA, $H_3PW_{12}O_{40}$) resulted in the highest activity and the highest number of acid sites and is thermally more stable than the other heteropoly acids. Note that preparation of HPA-promoted catalyst is entirely based on impregnation and could therefore relatively easily be upscaled. A corresponding study on HPA-promoted Cu/TiO_2 and Fe/TiO_2 delivered similar results regarding activity and potassium tolerance [62]. The best HPAs were reported to be $H_3PW_{12}O_{40}$ and $H_3PMo_{12}O_{40}$. Another study by Putluru et al. [46] showed the effect of vanadia loading (3–6 wt.%) on the activity, and potassium tolerance of HPA promoted V_2O_5/TiO_2 catalysts at temperatures below 300 °C. The optimum vandia loading was 5 wt.%, and the resulting catalysts were almost unaffected by 100 µmol K $g_{catalyst}^{-1}$ when tested at 225 °C.

The most active and potassium-tolerant catalyst published by our laboratory is a 20 wt.% V_2O_5/TiO_2 prepared by a sol-gel route [23,47,49]. This catalyst contains about 5 times as many acid sites as the VWT reference and is at least twice as active. The conversion of SO_2 to SO_3 at 380 and 420 °C was reported to be less pronounced than over the VWT reference. This is probably due to the amorphous nature of vanadia, which is a result of the special sol-gel method of preparation. Impregnation with 500 µmol K $g_{catalyst}^{-1}$ resulted in the catalyst being about as active as the VWT reference loaded with only 150 µmol K $g_{catalyst}^{-1}$. Pilot scale exposure to KCl aerosols has demonstrated that a 20 wt.% V_2O_5/TiO_2—sepiolite composite catalyst suffers relatively little deactivation under more realistic conditions because of sepiolite impeding the surface diffusion of potassium.

Other research groups have also made many contributions over the last 10 years. Peng et al. [63] reported on the effect of doping V_2O_5-WO_3/TiO_2 with Ce. $V_{0.4}Ce_5W_5$/Ti and $V_{0.4}W_{10}$/Ti loaded with 1% K convert 30 and 18% NO, respectively, when tested at 400 °C. Du et al. [64] investigated the effect of Sb and Nb additives to V_2O_5/TiO_2. Both Sb and Nb have promotional effects on their own and can act synergistically. At 300 °C, potassium loaded VTi and $VSb_{0.5}$NbTi show NO conversions of 22 and 43%, respectively. Gao et al. [65] reported on CeV mixed oxides supported on sulfated zirconia showing resistance to both SO_2 and potassium. The formation of $CeVO_4$ hinders the formation of $Ce_2(SO_4)_2$, and vanadia suppresses the absorption of SO_2, thus inhibiting NH_4HSO_4 formation. The potassium-loaded CeV mixed oxide catalyst maintains more than 95% NO conversion over 400 min of exposure to 600 ppm SO_2, while the conversion over the V free catalyst drops to about 65%.

To the best of our knowledge, very few reports exist on the potassium tolerance of hydrocarbon-SCR. Ethanol-SCR using Ag/Al_2O_3 is comparable in activity to NH_3-SCR over a 3 wt.% V_2O_5–7wt.% WO_3/TiO_2, however, is almost equally affected by potassium [66]. The mechanism of poisoning is not well understood but involves oxidation of ethanol to CO_2. Another problem with using ethanol instead of NH_3 as reductant is its much higher price. Furthermore, Ag/Al_2O_3 suffers from poor sulfur tolerance.

3. Conclusions

Different strategies of dealing with high concentrations of potassium in flue gases, typically present in biomass fired plants, were discussed. Addition of coal fly ash or other substances rich in alumino silicates like, e.g., kaolin is already an industrial practice and can very effectively bind potassium-containing aerosols. Lab scale experiments have demonstrated that this approach can be applied to various biomasses. The drawback of these additives is an increased concentration of particulates that need to be filtered off the flue gas. Tail-end placement of the SCR unit has also been demonstrated to work industrially. The major disadvantage of the tail-end placement, the expensive flue gas reheating to at least 180 °C, can, at present, not be avoided due to lack of catalysts that are sufficiently active, as well as due to sulfur and water tolerant at the outlet temperature of the desulfurization unit. Coating of shaped (monolith, plates) catalysts with thin layers of MgO or sepiolite was demonstrated to strongly reduce the rate of deactivation in pilot plant studies. The mildly basic nature of the protective layer impedes the diffusion of potassium ions into catalyst pores. Some of the studies report that the protective layer reduces the base activity by almost 50%, whereas others report a much lower penalty. Also, catalysts designed to tolerate higher loadings of potassium have been developed on a lab scale and include V, Cu, and Fe as active metals and heteropoly acid-promoted TiO_2, sulfated ZrO_2, and zeolites with a low Si/Al ratio as support materials. Most of the alternative catalysts gain their increased potassium tolerance from the addition of sacrificial acid sites. Since an increased number of acid sites was demonstrated to increase the potassium uptake from the flue gas, the addition of sacrificial sites probably only makes sense in conjunction with a protective layer of, e.g., MgO. The most promising results in this regard were obtained with a sol-gel prepared 20 wt.% V_2O_5/TiO_2 in combination with sepiolite. This composite material is about twice as active as the commercial, takes up less potassium from the flue gas, and experiences less deactivation per amount of adsorbed potassium. Avoiding the issue of reduced ammonia adsorption due to potassium uptake by using hydrocarbons as reductants has so far not been promising. We believe that mitigating the effect of potassium in biomass-fired units requires a multidimensional approach. For example, researchers should, if possible, demonstrate, using pilot plant studies, that promising catalyst formulations are also combinable with effective barrier materials that can minimize potassium uptake. Cost benefit analyses should also compare the use of alumino silicate addition with the use of potentially more expensive catalysts and tail-end placement of the SCR unit.

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Author Contributions: Leonhard Schill carried out the experimental work, design of figures and drafted the manuscript with further contribution from Rasmus Fehrmann who also managed the project.

Conflicts of Interest: The authors declare no conflict of interest.

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