Appendix U - 1

Public Comments Received on Public Review Draft SIP

National Parks Conservation Association et al. – Exhibits

Note: Exhibits 1 and 9 are accessible online:
https://apps.ecology.wa.gov/publications/summarypages/22-02-005.html

DEPARTMENT OF ECOLOGY
State of Washington

Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision

TransAlta Centralia Generation Plant

July 2020

Publication and Contact Information

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TransAlta Centralia Generation Plant

Air Quality Program

Washington State Department of Ecology

Olympia, Washington

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Table of Contents

Executive Summary

TransAlta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. In 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. The proposed mitigation is for TransAlta to install and operate a Combustion Optimization System with Neural Network (Neural Net) and have a lower nitrogen oxides (NOx) emission limit on the unit that is operational beyond 2020.

TransAlta was previously required to install Selective Non-Catalytic Reduction (SNCR) for control of nitrogen oxides emitted from their Centralia Power Plant. As a condition of the BART order issued to the facility, an optimization study was required to be performed and the results of that study implemented by the facility. After conducting the optimization study, TransAlta discovered that the ESPs were fouled from ammonia use required in the current BART order (Revision 1).

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

TransAlta, Southwest Clean Air Agency, and Ecology agreed on the conditions for Revision 2 for the BART order to include lower nitrogen oxides limits, changes to the use and monitoring of ammonia, and removal of the requirement to analyze the coal sulfur and nitrogen content.

Reason for this Revision

Trans Alta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. The proposed mitigation is for TransAlta to install in one boiler unit a Combustion Optimization System with Neural Network (Neural Net) in order to reduce the urea injection rate (the source of the ammonia). The other boiler unit is currently slated to cease coal-fired power generation on December 31, 2020 and is not scheduled to have the Neural Net installed. Ecology and Southwest Clean Air Agency are willing to accept a lower urea injection rate if TransAlta is willing to accept a lower nitrogen oxides emission limit. Ecology has determined that the nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission limit on one unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.
- Changing the language to "Permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives" to match the new language in the MOA.
- Removing the requirement to sample the coal for nitrogen and sulfur content.
- Removing the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement of a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Changing the requirement for ammonia emission monitoring only to require monitoring when using a urea injection rate of greater than 1.5 gallons per minute

Ecology is also modifying the compliance schedule to eliminate the requirement to demolish the coal units to align the BART order's language with language in the Memorandum of Understanding (MOA) between the State of Washington and TransAlta.

SNCR and Other Related Changes

The requirement to install SNCR along with the requirement to meet Washington's greenhouse gas emission performance standard was enacted by the legislature in 2010. The legislative requirement resulted in the first BART order revision. This first revision was finalized in December 2011 and approved by EPA December 16, 2012.

Originally, Revision 2 was intended to incorporate the results of the SNCR Optimization Study required by Condition 5 of the First Revision of the amended 2012 BART order. The study was to demonstrate the proper use of ammonia in controlling emissions of nitrogen oxides generated by the combustion of coal in the TransAlta boilers. Goals of the study were to determine how low nitrogen oxides emissions could be attained while meeting an ammonia slip limit of 10 ppm.

TransAlta completed the required ammonia injection optimization testing in two phases. The first phase was completed and the required report submitted in September 2014. Ecology and Southwest Clean Air Agency requested additional testing. This additional testing was performed and updated test results were submitted in August 2016. The updated test results were accepted by Ecology and Southwest Clean Air Agency on November 7, 2016. Ecology's letter accepting the final report included a requirement for urea injection in Unit 1 at 1.2 gallons per minute and 2.0 gallons/minute in unit 2. The prescribed urea injection level was constant for all power generation levels.

Condition 5 of the First Revision of the BART order required TransAlta to submit a request to revise the BART order to reflect the results of the study. In a letter dated November 28, 2016, TransAlta requested specific revisions to the BART order to reflect the findings of the study.

Before Ecology was able to take action on TransAlta's request, TransAlta started a third optimization study in response to a compliance order with Southwest Clean Air Agency. The intent of the third optimization study was to fine-tune certain plant operating parameters and verify the result of the second optimization study. The results of the third study would augment or replace the results of the previous studies. An initial SNCR optimization test plan was submitted to Ecology by email on February 6, 2019.

In the summer of 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. During a maintenance shut-down of the facility, the electrostatic precipitators (ESPs) were examined. The ESPs had a visual fouling of all interior components, which dramatically reduced their efficiency. Samples of the material in the ESPs were analyzed and identified as ammonia sulfate. The source of ammonia in the system was from the reactions of urea in the SNCR system.

To decrease the ammonia slip in the SNCR, TransAlta installed a computerized emission control system called a Combustion Optimization System with Neural Network program (Neural Net). The Neural Net is able to monitor and adjust more system variables at the same time than the manual control system. TransAlta notified Ecology and Southwest Clean Air Agency by email on July 8, 2019 of the installation of the Neural Net and the start of tuning the system.

TransAlta submitted a request on January 30, 2020 to modify Revision 1 of the BART order. The modification proposes the installation of the Neural Net and eliminates the mandatory urea injection requirements.

Revision 2 incorporates those changes and removes outdated requirements.

Compliance schedule related change

On July 13, 2017, the Memorandum of Agreement (MOA) between the State of Washington and TransAlta was amended. Subsection D(5) of the Recitals was modified. The 2011 MOA stated, "permanently cease power generation…" The 2017 MOA amendment reads:

> (5) permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA.

The change in the MOA does not require decommissioning of the units as envisioned (but not explicitly required) in 2011 with the passage of Chapter 180 (see Laws of 2011 - ESSB 5769 in 2011, codified in several locations). The change in the order reflects the pertinent portions of this law as codified in Chapters 80.80 and 80.82 RCW.

Ecology used the 2011 expectation that the plant would close to comply with the greenhouse gas emissions performance standard in RCW 80.08.040(3). Ecology also used the planned closure of the plant in the 2011 Regional Haze State Implementation Plan to project visibility benefits from the plant meeting the standard according to the schedule in the law. If power generation of the coal plant is replaced with a different form of combustion power generation (e.g., natural gas), the impact to regional haze would have to be analyzed separate from this BART order modification.

If TransAlta decides to switch to non-coal power generation, a Notice of Construction application would need to be submitted to Southwest Clean Air Agency by the company. Ecology would require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU). This is similar to what we would require of a new power plant to determine if it meets the requirements of WAC 173-400-117, special protection requirements for federal Class I areas.

Basis for Decision

SNCR related changes and optimization study

As directed by BART order revision 1 and RCW 80.80.040, TransAlta installed an SNCR system to reduce nitrogen oxides emissions from the boilers. The installation was based on a design study by the system vendor, NALCO-NOx Mobotec.

NALCO/Mobotec took system measurements adequate to model the combustion process and optimize the locations of ammonia injection into the boilers. Modeling indicated that due to the configuration of the boilers, the lowest nitrogen oxides emission rate anticipated would be approximately 0.195 lb/MMBtu, assuming that modifications to optimize combustion in the fireboxes for Powder River Basin (PRB) sub-bituminous coal were completed.

Only Unit 2 (aka BW22) was modified for optimizing the combustion of PRB coals. These modifications, proposed in 2007, are known as the Flex Fuels Project. Unit 1 (aka BW21) is not modified and the company indicates that it is unlikely that the modifications will be installed on this unit.

The installed SNCR system includes three levels of injection lances in each boiler. The actual lances used depends on the firing rate. In general, to avoid making nitrogen oxides by oxidizing ammonia, the higher lances are used at high firing rates and the lower lances are used at low firing rates.

Ammonia is supplied by using urea. Urea is received as a 40 percent by weight urea solution. The urea is supplied to the lances via a variable speed pump that can supply up to 6 gallons per minute of the 40 percent urea solution to an eductor system. The water provides some cooling to the hot flue gas and carries the urea well beyond the lance ports allowing the nitrogen oxides reduction to occur over more volume of the boiler. At maximum injection rates, the system is capable of injecting ammonia at approximately the stoichiometric rate for the SNCR reaction at maximum heat input.

The modeling by NALCO/Mobotec on maximum reduction of nitrogen oxides has proven to be accurate in practice. Boiler/SNCR system modeling indicated that the maximum expected nitrogen oxides reduction would give an emission rate of 0.195 lb/MMBtu. Testing indicates that on Unit 2, the maximum reduction is to 0.19 lb/MMBtu and for Unit 1, 0.20 lb/MMBtu.

The initial reduction testing (reported in the September 2014 Optimization Study report) indicated that at low injection rates, the installed SNCR systems did not reduce nitrogen oxides beyond the levels being achieved by the use of the installed combustion controls. There was no significant nitrogen oxides reduction when the SNCR and combustion controls were both operated concurrently. The 2014 Optimization Study report indicated that the combination of SNCR and combustion control could achieve 0.21 lb nitrogen oxides/MMBtu. The current nitrogen oxides emission limit has been set to the achievable emission level of 0.21 lb nitrogen oxides/MMBtu.

Ecology and Southwest Clean Air Agency required TransAlta to complete additional urea injection studies to determine the effects of injection rates of up to 6 gpm of 40 percent urea solution on nitrogen oxides reduction. Two test series on each boiler were done at 2 boiler operating rates:

- A series of 15-minute tests at an operating rate of 686 MW, gross, and
- A series of 15-minute and 4 hours tests were done at an operating rate of 600 MW, gross.

Conclusions of TransAlta's optimization study

In conclusion, the 2014 and 2016 test results indicate that the injection rates developed by NALCO/Mobotec as their optimum injection rates are very close to what has been demonstrated in the most current study. TransAlta presented rationale for why the emission limits in the BART order should not be adjusted downward.

TransAlta's rationale included a conclusion that the effectiveness of the SNCR system is affected by numerous operational parameters. The plant operators have control over some, while others are out of their control. Operating parameters include market driven operating rates, fuel blend, physical condition of the boiler and auxiliary equipment, fuel staging at burners, air flow distribution, burner tilt, soot blowing intervals, tube fouling, water wall slagging, and temperature in the convective pass of the boiler. TransAlta argued that because the uncertainties listed above, the BART order should not be adjusted.

Ecology's evaluation of the optimization data

Test results indicate that a small reduction in average nitrogen oxides emissions may be achievable. The actual reduction depends on several operating parameters. Ecology has evaluated the possibility of reducing the 30-day average limitation from 0.21 to 0.20 lb/MMBtu. We note that if both units operated at full rate for every hour of the year (i.e., the potential to emit), a 0.01 lb/MMBtu reduction equates to about 590 tons per year out of a potential to emit rate of 12,900 tons.

TransAlta's current permits require the operation of the SNCR system with urea injection and emission limits of 0.21 lb/MMBtu. The urea injection rate is creating ammonia slip. The ammonia generation is reacting with sulfur to create ammonia sulfate that is plating the surfaces in the ESPs. This creates conditions where the facility has to run at a reduced rate to continuing meeting emission requirements.

Neural Net

TransAlta initial proposal was to substitute the Neural Net to reduce the urea injection rate for each unit. Ecology and Southwest Clean Air Agency were willing to accept a lower urea injection rate, but wanted TransAlta to meet the short-term emission values of 0.18 lb/MMBtu for the unit with the Neural Net installed on it. In July 2019, TransAlta did not know the effectiveness of the Neural Net system. TransAlta requested a delay in agreement until more testing was done.

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

The main elements of the request are to:

- Install the Neural Net on Unit 2.
- Change the emission standard on Unit 2 to 0.18 lb/MMBtu from 0.21 lb/MMBtu.
- Allow TransAlta to use all methods and options they have available in any combination to meet the 0.18 lb/MMBtu standard.
- Change the ammonia monitoring requirements to reflect both historical readings and the change in urea injection rates.
- Remove the testing of coal for nitrogen and sulfur content as the facility would have to meet emission standards regardless of the coal used.
- Remove the reporting requirements for the coal nitrogen and sulfur content, as the test would no longer be performed.
- Change the permit language to reflect the new MOA language.

Compliance schedule related changes

The requirements of Chapter 80.80 RCW that sets the compliance schedule simply requires that to continue operation as a baseload power plant after the schedule in RCW 80.80.040(3)(c) and the BART order, each boiler must meet the greenhouse gas emission performance standard in effect on the day after the compliance dates. The standard is set by Washington Department of Commerce based on the emissions of combined cycle combustion turbines offered for sale and installed in the United States. This standard is currently 970 pounds of greenhouse gases/MWh. The standard is currently under review by Commerce for potential revision downward.

To continue operation after 2020 and 2025 with emissions above the greenhouse gas emission performance standard would require the plant owners to take an enforceable limit that keeps operations annually below a 60 percent capacity factor to avoid being classified as a baseload power plant under Chapter 80.80 RCW.

Ecology Analysis

The change in MOA language does not exclude the possibility that TransAlta could retrofit the facility to natural gas and continue operation. As the current BART order revision request does not address the future operation of the plant after 2025, any changes of this nature will require a separate action on the part of TransAlta. Until such time, it is assumed that TransAlta will cease all power generation activities by 2025.

Chapter 80.82 RCW was enacted in the same legislation that enacted special requirements for the Centralia Power Plant in Chapter 80.80 RCW. This law was drafted with the explicit understanding that the coal units would be decommissioned and demolished rather than repowered.

Ecology is aware that if TransAlta repowers the units on natural gas the visibility improvements anticipated by the current BART order and state implementation plan limits would not be met. Repowering would change the emission reduction used in determining the 2028 further progress goals for the nearby Class I Areas (Mt. Rainier and Olympic National Parks, and the Goat Rocks and Alpine Lakes Wilderness Areas) under the 2021 Regional Haze State Implementation Plan.

Proposed revision to emission limit in BART order

Ecology has determined that the small nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology has determined that a change in ammonia monitor is applicable with the change from a mandatory urea injection rate to a rate dependent on meeting a specific nitrogen oxides emission standard. TransAlta historic ammonia emission sampling at their current urea injection rate has never indicated excessive ammonia emissions. A large part in this finding is that the SNCR is upstream in the emission pathway from the wet scrubber. Free ammonia in the exhaust stream would be absorbed by the slurry stream in the wet scrubber, as ammonia is hydrophilic. These two factors allow for modification of the ammonia monitoring.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission standard on the second unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.

- Change the language to “permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives.” This to match the new language in the MOA.
- Remove the requirement to sample the coal for nitrogen and sulfur content.
- Remove the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Change the requirement for ammonia emission monitoring to reflect monitoring when using a urea injection rate of greater than 1.5 gallons per minute.

Proposed revision to compliance schedule in BART order

Ecology is proposing to modify the compliance schedule for coal units BW21 and BW22 to permanently cease coal-fired power generation operations by 2020 and 2025. This much more closely matches the requirement in the underlying state law.

Any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled. The modeling would have to meet both the requirements of BART modeling and satisfy the requirement of WAC 173-400-117. Since TransAlta has not requested repowering at this time, this issue will not be addressed in this BART order revision.

References

TransAlta’s SNCR Optimization Study Report, September 20, 2014

TransAlta’s SNCR Optimization Study Report, August 15, 2016

Ecology’s SNCR Optimization Study Report acceptance letter dated November 7, 2016

Letter to Nancy Pritchett and Uri Papish, dated November 28, 2016

Southwest Clean Air Agency Regulatory Order #16-3202, issued December 13, 2016

TVW recording of March 15, 2011 House Environment Committee

Emission calculation

Appendix:

Response to Comment

From:	Gent, Philip (ECY)
To:	emissol@emissol.com
Subject:	Response to submitted comment on TransAlta"s proposed BART Revision
Date:	Monday, July 27, 2020 4:39:00 PM

To whom it may concern,

You submitted a comment in regards to a proposed revision to the TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant's Best Available Retrofit Technology (BART) Order on 5/19/2020 at 1420. Below you will find your submitted comment and Ecology's response to your comment.

Submitted Comment

"Neural Network (NN) is a complex method and requires substantial testing, development and validation in order to make it work for any given environment. We trust the applicant has gone thru its due process for this development and demonstration. It is imperative that sufficient evidence is provided, showing a certain NN algorithm has been developed and specifically shown to work for the said environment in the powerplant."

Response to comment

Thank you for your comment. TransAlta along with Neuendorfer and Griffin Open Systems installed a temporary neural network interfacing with the plant distributed control system starting July 8, 2019. The system had no control elements and was only learning and modeling the systems. Griffin engineers built a model to perform predictive modeling and started to collect tuning data.

The neural network interface continued to collect tuning data and in October, 2019, TransAlta Corporate approved and issued an authorization for expenditure for the entire neural network installation. The installation plan was to have the neural network operational the first week of November. The actual transition time took longer than planned and the commission date was extended to December 19, 2019.

The months of installation and modification of the neural network in order to reduce and optimize NOx emissions gave TransAlta the confidence to request a change to their existing BART Order. From the time of control system commissioning (December 19, 2019 being the day Griffin and Neuendorfer left the site) until the unit came offline for the spring outage on February 11, 2020, average NOX emissions have been below 0.18 lb/MMBtu. As the request to lower the NOx emission limit came from the Permittee (TransAlta), it is incumbent on TransAlta to meet the limits.

No change was made to the BART Order as a result of this comment.

Philip Gent, PE
Senior Engineer
Policy & Planning Section
Washington Department of Ecology
(360) 407-6810
Philip.Gent@ecy.wa.gov

CataFlex™ catalytic filter bags

Remove pollutants and **trap** dust in one **single** step

Breakthrough catalytic filter bags trap dust, while removing dioxins, NOx and NH_3

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Are regulators putting the **squeeze** on your business?

Topsoe's CataFlex™ catalytic filter bags make compliance a whole lot more affordable

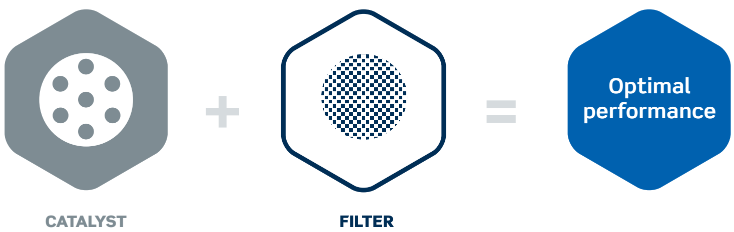
Authorities in many countries are tightening emissions standards by reducing permissible levels and adding new gases and particles to the list of regulated components. Compliance is costly, requiring substantial investments in new abatement technologies.

At Topsoe, we hear producers calling not just for new technologies, but for innovation that makes compliance affordable. That's what our CataFlex™ catalytic filter bags are all about.

Trap dust and remove pollutants
CataFlex™ are catalyst-coated filter bags designed to treat off-gases in high-dust environments found in a wide range of industries and activities, including:

- Waste incineration
- Biomass boilers
- Power plants
- Cement production
- Glass production
- Steel production

Built on decades of leadership in filtration and catalysis, these breakthrough solutions can transform the economics of meeting regulatory emissions.



The fact that we both master catalysts and process technology gives us the "big picture" view it takes to ensure optimal performance

Single step **removal** of dioxins, NOx and NH_3

Upgrading is easy and affordable

Topsoe's catalytic filter systems are designed to give any facility the option of treating off-gases along with trapping dust. CataFlex™ is the ideal choice for facilities already using a filter bag solution.

Designed for use in most industries that require flue gas cleaning, the CataFlex™ catalytic filter bag consists of a catalytic fabric layer installed inside a standard filter bag. Both the catalyst formula and the fabric material for the catalytic inner layer and the dust filtration layer are optimized according to the process requirements.

Benefits include:

- Removes dust and multiple gaseous compounds in a single step
- No need for costly, space-demanding tail-end SCR equipment
- Low pressure drop means no need for costly new ID fans or compressed air
- Accommodates operating temperatures up to 260°C (500°F)
- Bags can be inserted into existing filter houses for an affordable drop-in upgrade
- Life time and pressure drop is comparable to conventional fabric filters
- No contact between catalyst and potentially harmful particles
- Exceptional resistance to catalyst poisoning
- Length up to 10 m (32 ft)
- Longer outer bag lifetime

CataFlex™ catalytic filter bag

A broad spectrum of **regulated pollutants**

While the filters trap dust, the catalyst removes dioxins, NOx and NH_3

SEM image of CataFlex™

Outer layer

Dust
CataFlex™ effectively block particulates and dust particles on the outer layer which consist of a traditional dust filter bag, ensuring full compliance with the stringent emission standards.

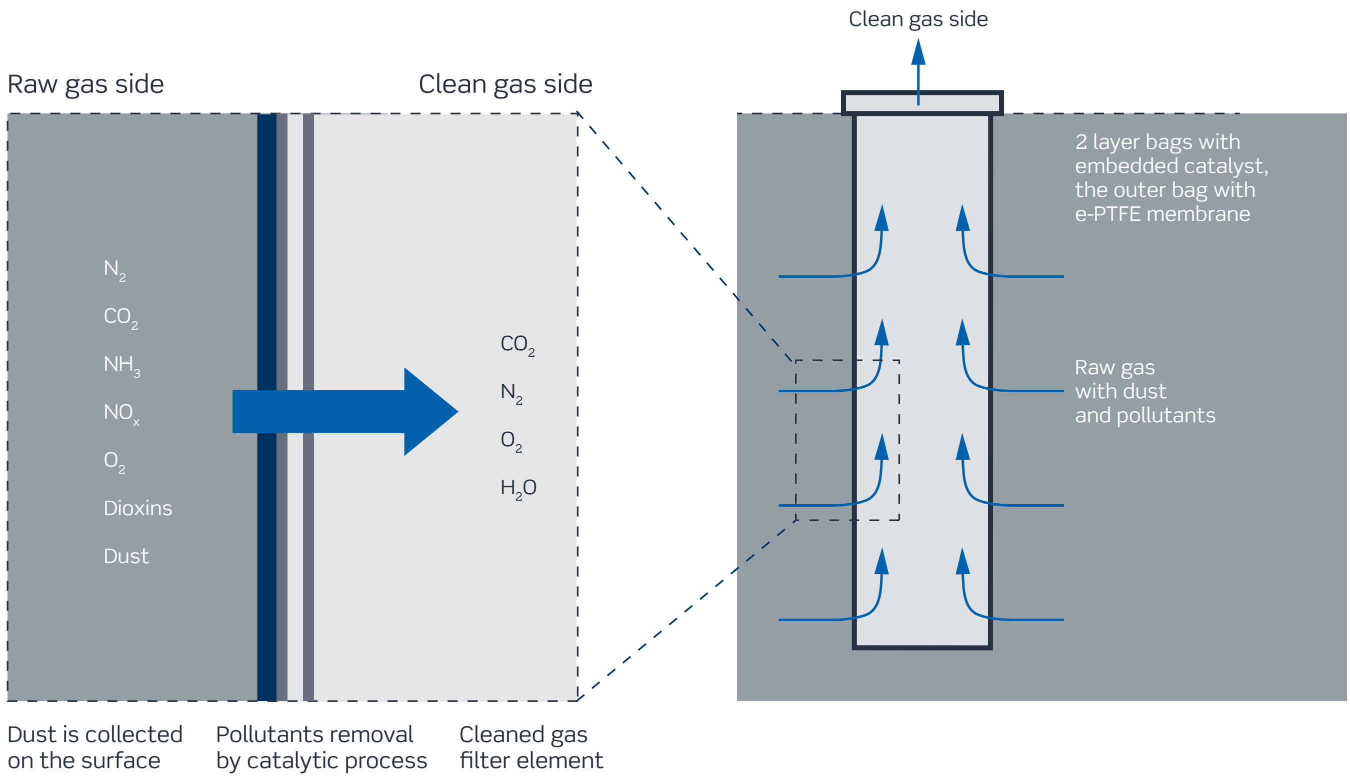
The outer layer of a CataFlex™ filter bag is a conventional filter bag which can be made by different fabrics and with and without PTFE membrane. CataFlex™ reduces dust emissions to below 1 mg/Nm³.

Inner layer

Dioxins destruction
CataFlex™ ensure compliance with limits on dioxins and furans - destruction more than 99% of these by converting them into harmless compounds and reducing their concentrations to below 0.1 ng-TEQ/Nm³.

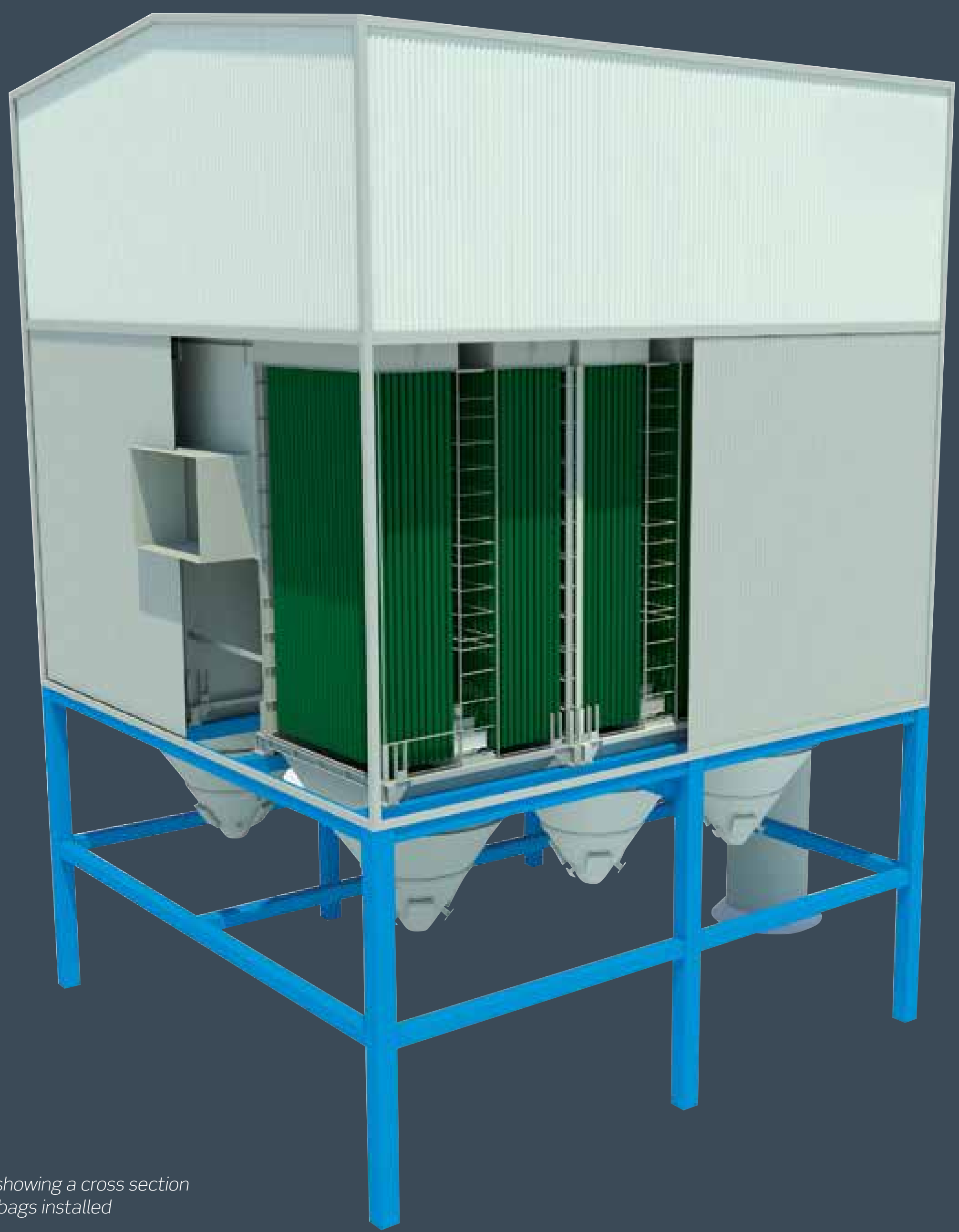
NOx
CataFlex™ use selective catalytic reduction (SCR) to remove NOx from off-gas, either by utilizing ammonia contained in the off-gas or via ammonia injection. The NOx is converted to harmless nitrogen and water.

NH_3
CataFlex™ eliminates any NH_3 slip from upstream selective non-catalytic reduction (SNCR) of NOx. This complies with NH_3 regulations and makes SNCR control easier.



Cut equipment **costs**

The Topsoe catalytic filter bag solution can help you reduce capital expenditures by up to 80% compared to competing solutions relying on separate dust removal and SCR technology.

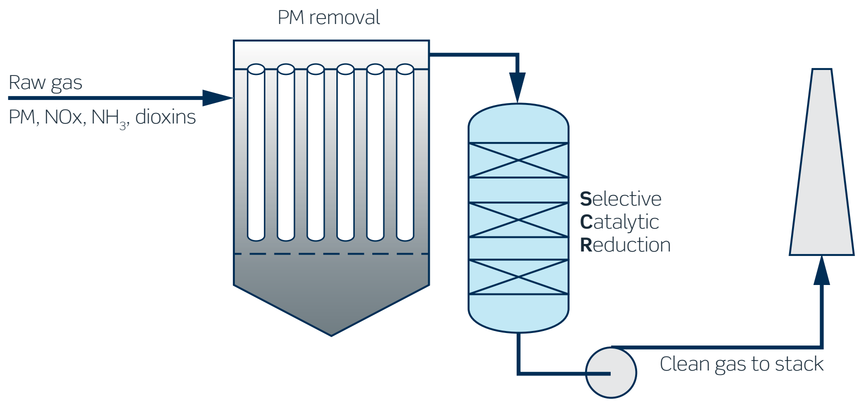


Typical fabric filter showing a cross section with catalytic filter bags installed

Filtration unit and tail end removal of NOx and NH_3

Traditional solution based on separated technologies

Non-catalytic filters

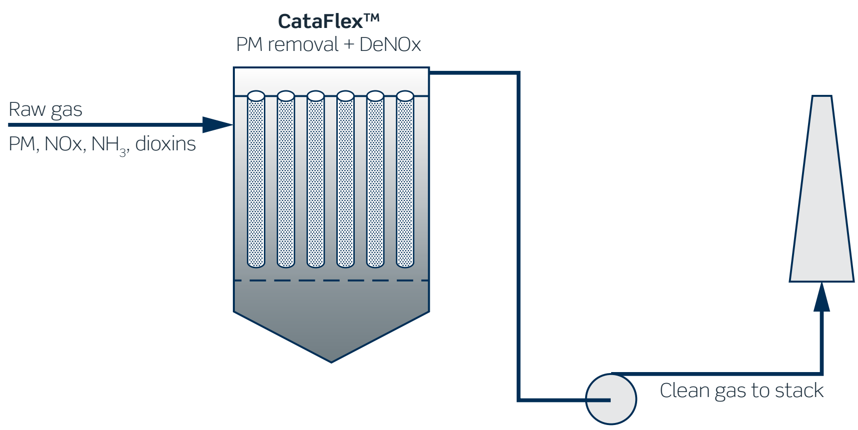


Catalytic filtration - integrated solution

Catalytic filter bag solution:

- Lower cost of ownership
- Less foot print
- Lower pressure drop
- Less maintenance

Catalytic filters



Related technologies

Discover the full range of Topsoe catalysts and technologies for optimizing performance

Optimized performance often means ensuring that multiple technologies and components are tuned to each other. If you're not already using them, please consider these related offerings from Topsoe.

S

Sulfur removal
As emission regulations continue to get tighter around the world, optimal handling of sulfurous gases is becoming increasingly important. In addition to meeting regulatory requirements, we make sure our solutions also make financial sense. Due to their high availability, energy efficiency and flexibility, our sulfur removal systems deliver market-leading performance. They can even be used to convert otherwise costly waste into valuable commercial-grade sulfuric acid.

VOC

VOC removal
Regulatory pressure on VOC emissions has never been greater, and we can help you meet the challenge by removing VOCs from off-gases via low-temperature catalytic processes. Our solutions deliver reduction efficiencies exceeding 99%, without creating any secondary pollutants. Our catalysts remove VOCs from air and waste gas streams in an energy-efficient and environmentally friendly manner.

Why partner with **Haldor Topsoe**

The Topsoe advantage lies not just in individual solutions, but in how our solutions work together

When you partner with Haldor Topsoe, you partner not only with the world's experts in catalysis, surface science and emissions management. You also partner with a company that takes a uniquely holistic approach to your plant and your business.

When we look at your plant, we look at the big picture – and then apply the full breadth of our expertise to deliver a thoroughly tailored solution, where individual components work together to maximize your plant's performance and your business success.

Haldor Topsoe is a world leader in catalysis and surface science. We are committed to helping our customers achieve optimal performance. We enable our customers to get the most out of their processes and products, using the least possible energy and resources, in the most responsible way. This focus on our customers' performance, backed by our reputation for reliability, makes sure we add the most value to our customers and the world.

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Haldor Topsoe A/S, cvr 41853816 | GMC | 0268.2019/Rev.1

HALDOR TOPSØE

Catalytic Filter Technology Provides Important Flexibility for Controlling PM, NOx, SOx, O-HAPS

Catalyst-embedded ceramic filters offer a way to remove NOx at lower temperatures, while simultaneously removing PM, SOx, and HCl. The technology also removes organic hazardous air pollutants, THC, dioxins, and mercury.

Applications include the Cement NESHAP; Boiler MACT; incinerator CISWI MACT; Hazardous Waste MACT; glass furnaces; ceramics manufacturing, including fracking proppants, kilns, and thermal oxidizer clean-up.

Typically, PM is removed to ultralow levels (≤5 mg per Nm3, 0.002 grains per dscf); other pollutants are eliminated at levels >90%.

Filter Types: Standard and Catalyst

Standard UltraTemp filters remove PM or PM plus acid gases and metals, including mercury; UltraCat catalyst filters remove those, plus O-HAPS, dioxins and NOx.

Catalyst filters feature the same fibrous construction as the standard version, but have nanobits of catalyst embedded throughout the filter walls. Distribution across the entire wall thickness, as opposed to just a catalyst layer, creates a very large catalytic surface area. The walls that contain the catalyst are about 3/4 inches thick. Ammonia is injected upstream of the filters and reacts with the NOx at the surface of the micronized catalyst to destroy the compound (Figure 1).
An analysis comparing the effectiveness of this nanocatalyst with that of conventional catalysts was summarized in a paper by Schoubye and Jensen of Haldor Topsoe A/S:

"The catalyst particles are micro-porous, and, due to their small size, they catalyze the gas-phase reactions without diffusion restriction (i.e., almost 100% utilization of the catalyst's intrinsic \activity), as opposed to pellet or monolithic catalysts. In industry, conventional catalyst types typically operate with 5-15% catalyst effectiveness in the SCR of NOx by NH3 and with even lower catalyst utilization in dioxin destruction."

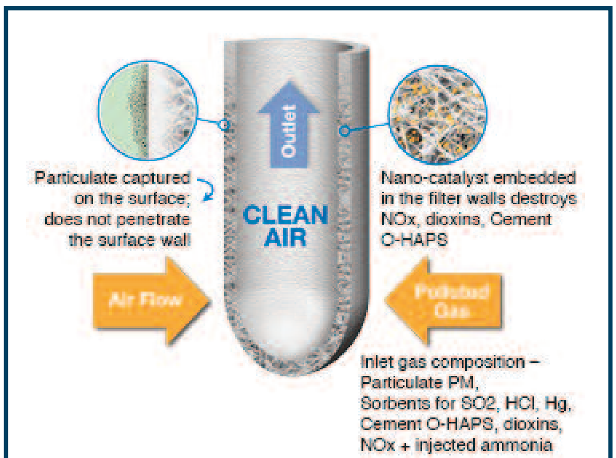

Figure 1. Catalytic filter schematic.

Another remarkable feature is low temperature activation. Substantial NOx removal is initiated at 350°F, with over 90% removal as the temperature exceeds 450°F.

System Design Criteria

Filters are placed in a housing module configured like a reverse pulse jet baghouse. Polluted airstream enters the bottom of the housing. Process PM and reacted acid gas sorbent PM are captured on the filter surfaces, while NOX and injected aqua ammonia are transformed to nitrogen gas and water vapor. O-HAPS (Cement NESHAP) and dioxins are broken down without ammonia additions. Cleaned air passes through the center of the filter tubes and out of the space above (Figures 1-3).

The modular housing design allows filters to be configured for the largest gas flow volumes. The system's modular nature also provides redundancy so a single module can be taken offline while the other modules receive the flow.

Placing multiple plenums in parallel provides redundancy. If one plenum is taken offline for service, others treat the entire flow at a temporarily higher pressure with no change in performance.

Particulate is captured on the face of the filter and does not penetrate the filter. At start-up, the pressure drop is 6" w.g. Over the filter's life, the pressure undergoes a gradual increase, averaging 3% annually. Filter life is generally over 10 years. Conventional reverse pulse jet methods are used for filter cleaning.

Standard Filter: Typical Pollutant Control

Particulate: The typical level of particulate at the outlet of the ceramic filters is ≤ 0.002 grains/dscf (5 mg/Nm^3).

With the exception of mercury, heavy metals are captured at the same rates as other particulate (> 99%).

SO_2, SO_3, HCl, other acid gases: Ceramic filters use dry injection of calcium or sodium-based sorbents for acid gas removal. Injected in the duct upstream of the filter modules, the additional sorbent particulate is captured with its pollutant gas. The reaction of the sorbent with the acid gas creates a solid particle that is captured on the filters alongside the unreacted sorbent and process particulate. The reaction occurs within the duct prior to the filter and on the cake on the filter surface.

The sorbent cake on the filters increases exposure of the SO_2 or HCl, and increases removal rate. For a given removal efficiency, filters require significantly less sorbent than ESPs, which minimizes sorbent costs.

With sorbent injection, SO_2 removal is above 90%. SO_3 and HCl are preferentially removed at higher rates than SO_2. Sorbent injection of powdered activated carbon is an option for mercury control. The mercury chemistry and temperature of the application determine the formulation of PAC used and the resulting effectiveness.

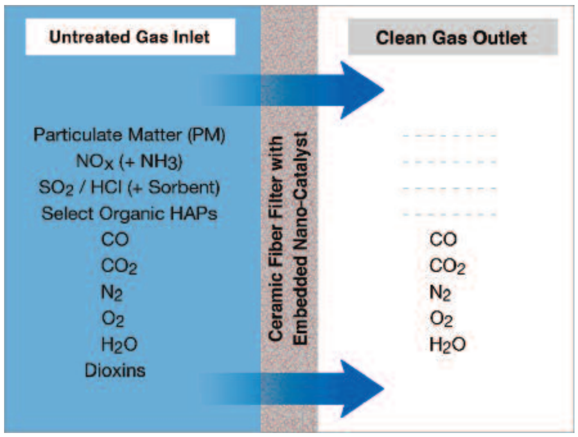

Figure 2. Catalyst filters simultaneously treat multiple pollutants.

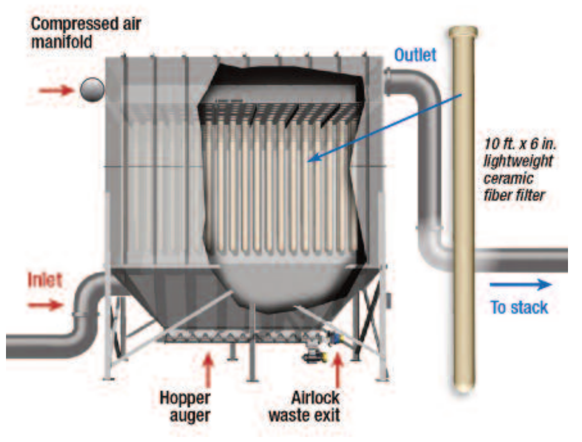

Figure 3. A single housing module containing 3m filter elements.

surface, and gas-phase poisons. A common problem with "honeycomb block" SCR is that the catalyst becomes blinded and poisoned, reducing effectiveness and necessitating replacement. Ceramic catalyst filters address these issues. Particles, including solid-phase metals, are captured on the surface of the filters.

The filter catalyst is distributed throughout the filter walls and is protected inside the filter. This virtually eliminates particulate-type interactions and extends catalyst life. Regarding gas phase, the proprietary catalyst formulation is engineered for extremely low conversion of SO_2 to SO_3 and is virtually immune to HCl.

The reaction of the ammonia and NOx at the micronized catalyst surface is the same as conventional SCR, but benefits from more contact time because the gas mixture doesn't have to diffuse in and out of the block catalyst pores.

Eliminating the diffusion restriction helps reduce the slippage of untreated gases; NOx destruction greater than 90% is common. Ammonia slip is under 10 ppmv.

Cement O-HAP THC: The filters destroy formaldehyde and other O-HAPS. The significant reduction of O-HAPs results in an adjustment of total allowable THC according to NESHAP. This direct approach for O-HAPS reduction is very cost effective compared to PAC injection or thermal oxidation.

Catalytic filters virtually eliminate ammonia slip if SNCR is used in the kiln. Excess ammonia slip is consumed by the filters while acting as a polishing step for NOx removal. This is an important secondary benefit when the filter system is used to collect PM, remove HCl, and/or destroy O-HAPS. Thus the need for a fabric filter baghouse or ESP is eliminated.

Dioxins: Dioxins are destroyed similarly by the catalytic filter.

Operating Temperatures
For PM plus SO /HCl, the range is 300 to 1,200°F.

One important feature of the NOx filters is an operating range that is lower in temperature compared to conventional SCR. Conventional SCR requires 550°F for efficient removal, while the micronized catalyst becomes active at 350°F (Table 1).

O-HAP destruction becomes effective as temperatures approach 400°F and increases rapidly.

Table 1. Temperature ranges by pollutants being removed.

UltraCat Filter	Pollutants	Temp Range
Non-catalytic	PM, SOx, HCl, Hg	300°F - 1,200°F
Catalytic	PM, SOx, HCl, Hg, NOx, O-HAPs, Dioxins	350°F - 750°F

Catalytic Filters for NOx, O-HAP THC, Dioxins
Catalytic filters have the same composition and capabilities as the non-catalytic filters for PM, acid gases and Hg. The difference is the micronized catalyst into the filter walls.

NOx: All catalysts can be compromised by particulate blinding of the catalyst surface, chemical interactions with particulate on the

Proven Solution
Ceramic filters have been used by the U.S. military at munitions destruction facilities for 20 years; hundreds of ceramic filter systems are operating worldwide. With the additional capability of NOx control, ceramic filter systems are the technology of choice for many applications.

Wingra Engineering, S.C.
Environmental Engineering Consultants

September 23, 2021

National Parks Conservation Association
Clean Air and Climate Program
Attn: Stephanie Kodish, Senior Director & Counsel
777 6th Street NW, Suite 700
Washington, DC 20001-3723

Subject: Four-Factor Reasonable Progress Analysis
GCC Rio Grande – Pueblo Cement Plant
Pueblo, Colorado

Dear Ms. Kodish:

The National Parks Conservation Association requested the preparation of a Four-Factor Reasonable Progress Analysis for GCC Rio Grande – Pueblo Cement Plant in Pueblo, Colorado. This analysis evaluates the feasibility of installing emission control equipment for air pollutants which are precursors to regional haze. The enclosed report describes the procedures and results of this analysis.

Should you have further questions, please contact me at (608) 255-5030.

Sincerely,

Wingra Engineering, S.C.

Steven Klafka

Steven Klafka, P.E., BCEE
Environmental Engineer

Enclosure

GCC Rio Grande – Pueblo Cement Plant

Pueblo, Colorado

Four-Factor Reasonable Progress Analysis

September 23, 2021

Prepared by:

Steven Klafka, P.E., BCEE

Wingra Engineering, S.C.

Madison, Wisconsin

1.0 INTRODUCTION

The Colorado Department of Public Health and Environment (CDPHE) Air Pollution Control Division is updating its regional haze state implementation plan to improve visibility in certain national parks and wilderness areas in the state. These are referred to as Class I areas for implementation of air pollution protection regulations.

CDPHE is evaluating the retrofit of emission control technology at large industrial sources to make reasonable progress toward natural conditions in Class 1 areas. To determine the effectiveness of retrofitting emissions control technology, USEPA requires states to use a Four-Factor Reasonable Progress Analysis (FFA).

The four statutory factors included in an FFA are:

- Costs of compliance
- Time necessary for compliance
- Energy and non-air quality impacts of compliance
- Remaining useful life of any potentially affected sources

CDPHE has identified the GCC Rio Grande – Pueblo Cement Plant located in Pueblo, Colorado as potentially having impacts on regional haze at surrounding Class I areas. CHPHE recently conducted its own FFA entitled, *Regional Haze Second 10-year Planning Period, Reasonable Progress Four-Factor Analysis of Control Options for GCC Rio Grande - Pueblo Cement Plant*, August 2021.

This report updates the CDPHE analysis by incorporating recent improvements in available air pollution control systems for cement kilns. The CDPHE analysis did not address these control methods.

2.0 FACILITY DESCRIPTION

GCC Rio Grande – Pueblo Cement Plant is located at 3372 Lime Road in Pueblo, Colorado. It manufactures Portland cement. This requires that a mixture of quarried materials, including limestone and clay, be heated at high temperatures in a rotary pre-heater/pre-calciner kiln. This kiln is the primary source of air pollution emissions at the plant and is identified as Emission Point 039. The plant has not been issued an air quality operating permit. It currently operates following the requirements summarized in Facility Wide Construction Permit No. 98PB0893 Issuance 8 Correction.[1]

The kiln has a rated capacity of 3,750 tons per day and is fired with coal, natural gas and tire derived fuel. Currently, emissions are controlled using the following methods:

- Particulate Matter (PM) – Baghouse
- Sulfur Dioxide (SO_2) – Scrubbing inherent in the contact of SO_2 with the alkaline materials in the kiln.
- Nitrogen Oxides (NO_x) – Use of Selective Non-catalytic Reduction or SNCR by injection of ammonia into the high temperature areas of the kiln.

Allowable and uncontrolled emissions in units of tons per year (tpy) from the kiln are summarized in Table 1. Uncontrolled emissions for PM and NO_x are based on USEPA emission factors of 250 and 4.2 lbs/ton, respectively. For SO_2, it has been assumed that there is no difference between the allowable and uncontrolled emissions since the uncontrolled emissions are naturally controlled by the kiln.

Supporting calculations are provided in Appendix A.

[1] Colorado Department of Public Health and Environment, Air Pollution Control Division, Field Inspection Report, January 22, 2020.

Table 1 - Allowable and Uncontrolled Emissions from GCC Rio Grande – Pueblo Cement Kiln (tpy)

Air Pollutant	PM_{10} (Filterable)	PM_{10} (Condensable)	PM_{10} (Total)	SO_2	NO_x	Total
Allowable	36.0	293.6	329.6	943.4	1,100.0	2,373.0
Uncontrolled	171,093.8	45,875.0	216,968.8	943.4	2,874.4	220,786.5

3.0 CDPHE FOUR-FACTOR ANALYSIS

The Four-Factor Analysis or FFA completed by CDPHE concluded that no emission control systems or methods are available for the GCC Pueblo kiln. No changes were made to the allowable emissions from the kiln or the GCC plant. A copy of their draft analysis is provided in Appendix B.

For the control of NO_x, CDPHE evaluated the use of Selective Catalytic Reduction (SCR) to replace the current Selective Non-catalytic Reduction (SNCR). CDPHE estimated the current SNCR is achieving a NO_x emission reduction of 53.6%. SCR has been shown to provide NO_x emission reduction of 90% or more. SNCR requires the injection of ammonia in high temperatures (1,600 to 2,000°F) while SCR requires the injection of ammonia at lower temperatures (450 to 800°F) where control occurs in a ceramic catalyst. CDPHE rejected the use of SCR to attain greater NO_x emission reductions due to the likelihood of catalyst plugging by PM, mostly the condensable form, and the lack of experience on cement kilns.

For the control of PM, CDPHE determined that the existing baghouse provided state of the art capture of filterable PM and no better controls were available. The large amount of condensable PM could be minimized by tight control of the ammonia injection used by the SNCR control system for NO_x. CDPHE concluded that "These inorganic ammonium salts form when excess ammonia from the SNCR, known as ammonia slip, reacts with chlorides and sulfates from the raw materials and coal."

For the control of SO_2, CDPHE did not evaluate control methods since actual emissions from the inherent scrubbing within the kiln were already low.

4.0 OTHER AVAILABLE EMISSION CONTROL SYSTEMS

There are practical impediments to using a traditional SCR control system for the kiln due to potential plugging by PM emissions. However, the shortcomings of traditional SCR have been overcome with the availability of recently available catalytic ceramic filter systems. These systems are in use throughout the U.S., but with limited application at cement plants. There is greater application of these systems at cement plants in Europe. These systems combine the PM removal conducted by a baghouse with the NO_x removal of SCR. In its FFA, the CDPHE did not evaluate the use of ceramic filter systems.

The advantages of catalytic ceramic filter systems are as follows:

1. Injection of ammonia at low SCR filter temperatures rather than the high SNCR temperatures, thus avoiding the formation of condensable PM within the kiln.

2. More efficient usage of ammonia reducing ammonia slip.

3. Larger reductions in NO_x emissions, as the control efficiency is increased from 53% (estimated by CDPHE for GCC) to greater than 90%.

4. Simultaneous capture PM emissions.

5. Simultaneous control of SO_2 emissions when combined with reagent injection.

There are two design alternatives for catalytic ceramic filters:

1. Stand-alone catalytic ceramic filter systems

2. Catalytic ceramic filter inserts for existing baghouses

Manufacturers of these filter systems include: Tri-Mer [2], GEA Bischoff [3], and Haldor Topsoe A/S [4]. All three firms were contacted for this study. They all cite the ability to control emissions in the cement industry. The first two firms offer catalytic ceramic filters. These catalytic ceramic filter systems combine into a single control device the traditional separate systems for each air pollutant, as the systems typically include a scrubber for SO_2 neutralization, baghouse for PM capture and SCR for NO_x control. Brochures for the catalytic ceramic filter control systems offered by these two firms are provided in Appendices C and D, respectively.

The last firm, Haldor Topsoe, produces both: 1) a catalytic filter candle (called TopFrax) and 2) a catalytic filter bag (called Cataflex). The filter candles are similar to those used inside the Tri-Mer and GEA systems. The catalytic filter bag, however, is a product that can be added to an existing

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[2] https://tri-mer.com/hot-gas-treatment/hot-gas-filtration.html
[3] https://www.gea.com/en/news/trade-press/2019/biscat-ceramic-catalyst-filter.jsp
[4] https://www.topsoe.com/products/catalysts/topfraxtm

baghouse. These catalytic filter bags have the advantage of reduced cost. They avoid the need for a separate stand-alone control system by instead inserting the catalytic filter bags into the fabric bags of the existing baghouse used to control PM emissions. Brochures for both the catalytic filter candles and bags provided by Haldor Topsoe are provided in Appendix E. Tri-Mer notes that it also has experience with the installation of catalytic filter bags on existing baghouses.

Tri-Mer has extensive experience in the U.S. using their catalytic filter control systems to simultaneously control PM, SO_2 and NO_x emissions from high temperature glass furnaces. Current installations in the U.S are summarized in Table 2.

Tri-Mer also has updated existing baghouses by replacing the fabric filter bags with catalytic ceramic filters. This approach modifies the baghouse to allow the control of NO_x emissions on the ceramic filter.

Table 2 - Tri-Mer Filter Projects in U.S.

Company	Location	Glass Type
Durand	Millville, NJ	Tableware
Anchor	Monaca, PA	Mixed
AGC	Church Hill, TN	Flat
Gallo	Modesto, CA	Container
AGC	Hill, KS	Flat
Adagh	Dolton, IL	Container
Kohler	Kohler, WI	Specialty
Guardian	Carleton, MI	Flat
PG Corporation	L.A. Basin	Specialty
Cardinal FG	Mooresville, NC	Flat
Cardinal FG	Durant, OK	Flat

Haldor Topsoe worked with FLSmidth to install a ceramic filter system after a baghouse used on the cement kiln at Cemex Southeast LLC cement plant in Demopolis, Alabama. This ceramic filter system was used to control hazardous organic compound emissions.[5] Haldor Topsoe have also used their catalytic filter bags to control NO_x emissions from cement kilns in Europe.

Figure 1 provides a diagram of a stand-alone catalytic ceramic filter system offered by Tri-Mer.

Figure 2 shows the catalytic filter bag inserts (called Cataflex) offered by Haldor Topsoe.

It is noteworthy that CDPHE recently completed an FFA for the Rocky Mountain Bottle Company which has a glass furnace equipped with the Tri-Mer system.

[5] https://www.cemex.com/documents/20143/49694544/IntegratedReport2019.pdf/4e1b2519-b75f-e61a-7cce-2a2f2f6f09dc

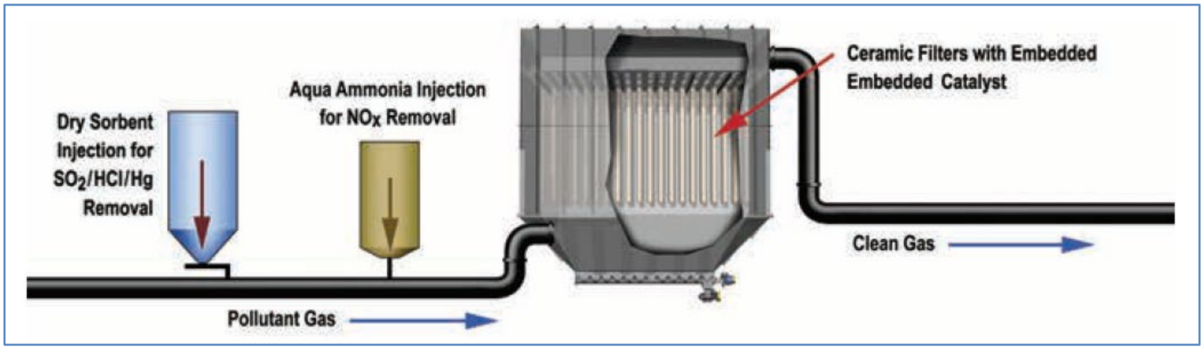

Figure 1 - Catalytic Ceramic Filter System

Figure 2 - Catalytic Filter Bag Insert

The configuration of the existing GCC Rio Grande – Pueblo cement plant has been discussed with the three vendors. Potential emission control options include the following:

1. Insertion of catalytic filters into the existing baghouse.

2. Installation of a ceramic filter system after the existing baghouse.

3. Replacement of the existing baghouse with a stand-alone ceramic filter system.

The least expensive option is the first – installing catalytic filter bags into the fabric bags of the existing baghouse or replacing the fabric bags with ceramic filter elements. This approach would retain the footprint of the existing baghouse and stack with the least physical modifications.

The remaining two options would be more costly and require the purchase of a stand-alone ceramic filter system. For the second option, the existing baghouse and SNCR system would be retained. There would be less air pollution emissions to control and additional cost to reheat the flue gas to the catalyst operating temperature. For the third option, the existing baghouse and SNCR system would be removed. There would be more air pollution emissions to control and no need to reheat the flue gas.

5.0 COSTS OF COMPLIANCE

Cost estimates were developed for the following three emission control alternatives not considered by CDPHE in its FFA:

1. Installation of a stand-alone Tri-Mer catalytic ceramic filter system, while retaining the existing baghouse and SNCR control system. This approach would simultaneously control PM, SO_2 and NO_x emissions.

2. Replacement of the existing baghouse with a stand-alone Tri-Mer catalytic ceramic filter system. This approach would simultaneously control PM, SO_2 and NO_x emissions

3. Replacement of the fabric filter bags of the existing baghouse with catalytic ceramic filter elements. This approach would add the control of NO_x emissions.

5.1 Cost of Catalytic Ceramic Filter System

For typical Best Available Control Technology analyses, order-of-magnitude cost estimates are typically generated.[6] The cost estimate is improved if it is based on actual vendor quotations for the required equipment. Developing air pollution control cost estimates is a time-consuming process. Rather than request budget quotations from vendors, a cost estimate was developed from a 2015 proposal for a Tri-Mer catalytic ceramic filter system sized for a 700 tons per day flat glass plant. This system was eventually installed in North Carolina and continues to operate successfully. This glass plant cost estimate reflects the retrofit of a new control system at an existing industrial facility.

The capital, installation and operating costs were adjusted to reflect the differences between the glass plant and the cement kiln at the GCC Rio Grande – Pueblo cement plant. Adjustments accounted for inflation, inlet air flow rates and uncontrolled emission rates of PM, SO_2 and NO_x. Supporting cost estimation calculations are provided in Appendix A.

If the existing baghouse is retained for the first option, the exit temperature of the flue gas would be too low for the use of a catalytic reduction system. The cost estimates include the cost of natural gas to reheat the flue gas to the control system operating temperature of 550 °F.

If the existing baghouse is removed and replaced with the catalytic filter system for the second option, it was assumed that operation of the cement plant gas cooler prior to the baghouse could instead be adjusted to increase the flue gas temperature to that required for the catalyst.

Table 3 summarizes the cost estimate for options 1 and 2. Because the catalytic ceramic filter system is a multi-pollutant control technology, cost effectiveness was calculated based on the total

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[6] USEPA, Air Pollution Control Manual, Sixth Edition, EPA/452/B-02-001 January 2002.

expected emission reductions of NO_x alone, and for PM, SO_2 and NO_x combined.

For the first option, adding a new ceramic catalytic filter system after the existing baghouse and SNCR system, the estimated cost effectiveness to is $6,211 per ton for the removal of NO_x emissions. The cost effectiveness is $3,550 per ton for the removal of combined emissions of PM, SO_2 and NO_x. This is based on controlling the allowable emissions exiting the current baghouse and SNCR system.

For the second options, replacement of the existing baghouse and SNCR system with a new ceramic catalytic filter system, estimated cost effectiveness is $1,889 per ton for the removal of NO_x emissions. The cost effectiveness is $29 per ton for the removal of combined emissions of PM, SO_2 and NO_x. This is based on controlling the uncontrolled emissions exiting the current cement kiln.

This analysis shows that either option has cost effectiveness values which are reasonable and fall within the range that has been accepted by regulatory agencies. The enclosed cost estimate would be improved if a budget quotation were obtained for the cement kiln at the plant.

Table 3 - Cost Estimate for Catalytic Ceramic Filter System

Capital Costs	GCC Rio Grande	GCC Rio Grande
Location of New Catalytic Filters	After Baghouse	Replace Baghouse
Emissions Basis	Allowable	Uncontrolled
Complete System Equipment and Installation	$31,278,404	$31,278,404
Capital Recovery Factor (CRF)	0.06878	0.06878
Annualized Capital Cost	$2,151,329	$2,151,329
Operating Costs		
Electricity	$831,274	$831,274
19% Aqueous Ammonia	$366,195.36	$956,893
Hydrated Lime	$768,162.99	$768,163
Labor for Operation and Maintenance	$178,033	$178,033
Natural Gas for Reheating Flue Gas	$1,854,147	$0
Annual Operating Costs	3,997,812	2,734,363
Combined Capital and Operating Costs		
Capital Costs	$31,278,404	$31,278,404
Annual Capital Costs	$2,151,329	$2,151,329
Annual Operating Costs	$3,997,812	$2,734,363
Annual Capital and Operating Costs	$6,149,141	$4,885,692
Inlet NO_x (tpy)	1,100	2,874
Inlet SO_2 (tpy)	943	943
Inlet PM (tpy)	36	171,094
Inlet NO_x, SO_2 and PM (tpy)	2,079	174,912
Outlet NO_x (tpy)	110	287
Outlet SO_2 (tpy)	236	240
Outlet PM (tpy)	2	7,129
Outlet NO_x, SO_2 and PM (tpy)	347	7,656
Removed NO_x (tpy)	990	2,587
Removed SO_2 (tpy)	708	704
Removed PM (tpy)	35	163,965
Removed NO_x, SO_2 and PM (tpy)	1,732	167,256
Cost Effectiveness ($ per ton of NO_x removed)	$6,211	$1,889
Cost Effectiveness ($ per ton of total removed)	$3,550	$29

5.2 Cost of Catalytic Filters

Tri-Mer was provided with the design specifications of the existing cement kiln. These are the same as those used to develop the preceding cost estimates for a stand-alone catalytic ceramic filter system.

Based on the design of the existing cement kiln and its air pollution control system, Tri-Mer prepared a proposal to replace the existing fabric filter bags in the baghouse with catalytic ceramic filter elements. This approach would continue to provide control of PM emissions, but add the ability to control NO_x emissions by 90% or more. If desired, reagent injection such as lime could be used to control SO_2 emissions. A copy of the Tri-Mer proposal is provided in Appendix F of this report.

Tri-Mer assumed the existing SNCR system would be discontinued so uncontrolled NO_x emissions would be controlled by the new filters. To achieve the required operating temperature of 550 °F, the exhaust flue gas of the cement kiln would no longer be cooled to a temperature required by the existing fabric bags.

Based on their estimated capital and operating cost estimates, Tri-Mer developed a cost effectiveness of $800 per ton of NO_x removed. This estimate is reasonable and falls within the range that has been accepted by regulatory agencies. The enclosed cost estimate would be improved if a budget quotation were obtained for the cement kiln at the plant.

Other benefits of this control option cited by Tri-Mer include the following:

- Minimal catalyst plugging
- Reduced ammonia slip
- Negligible catalyst deactivation
- Minor conversion of SO_2 to SO_3

Each of these addresses concerns raised by CDPHE for the use of SCR in its draft FFA.

6.0 TIME NECESSARY FOR COMPLIANCE

Based on prior projects, the time frame to obtain a quotation for a catalytic ceramic filter system or catalytic filter bags, issue a purchase order, complete engineering, construct and install the equipment is 12 months.

7.0 ENERGY AND NON-AIR QUALITY IMPACTS OF COMPLIANCE

Significant operating costs include electricity, ammonia reagent, hydrated lime reagent and labor. These costs are taken into account in the enclosed cost estimates. The cost estimates provided in this report incorporate electricity usage for control system fans.

The ammonia selected for the control of NO_x emissions is 19% aqueous ammonia. This is a less concentrated and safer alternative to anhydrous ammonia. This type of ammonia has no federal requirement to evaluate the potential impacts of an accidental release.

The calcium sulfate (i.e., gypsum) formed by the reaction of hydrated lime with SO_2 will be captured as dust by the ceramic filters. Calcium sulfate is a raw material in cement. It is possible the capture dust can be used as one of the ingredients in the production of cement and avoid landfilling.

8.0 REMAINING USEFUL LIFE OF ANY POTENTIALLY AFFECTED SOURCES

In its FFA, CDPHE concluded that GCC has not announced a closure date for the Pueblo kiln or its associated limestone quarry, and CDPHE assumed that the cement kiln will remain in operation for at least 20 years.

9.0 CONCLUSIONS

The draft FFA prepared by CDPHE for the GCC Rio Grande – Pueblo cement plant concluded there were no feasible control systems available to further reduce emissions. The use of catalytic ceramic filter systems was not considered by CDPHE. These systems are in operation in the U.S. and are suitable for cement kilns.

The enclosed estimates show that for the first option, adding a new ceramic catalytic filter system after the existing baghouse and SNCR system, the estimated cost effectiveness to is $6,211 per ton for the removal of NO_x emissions. The cost effectiveness is $3,550 per ton for the removal of combined emissions of PM, SO_2 and NO_x. This is based on controlling the allowable emissions exiting the current baghouse and SNCR system.

For the second option, replacement of the existing baghouse and SNCR system with a new ceramic catalytic filter system, estimated cost effectiveness is $1,889 per ton for the removal of NO_x emissions. The cost effectiveness is $29 per ton for the removal of combined emissions of PM, SO_2 and NO_x. This is based on controlling the uncontrolled emissions exiting the current cement kiln.

For the third option, replacement of the existing fabric filter bags with catalytic ceramic filter elements, the cost effectiveness would be $800 per ton for the removal of NO_x emissions.

All of these values represent a reasonable expenditure for the reduction of PM, SO_2, and NO_x emissions. There are no other impediments to the use of these control systems associated with time of installation, energy and non-air impacts, or the anticipated life of the existing cement plant.

Appendix A

Supporting Cost Calculations

Facility	GCC Rio Grande			Reference
	Pueblo Cement Plant			A
	Pueblo, Colorado			A
	Preheater/Precalciner Kiln			A
AIRS Point	039			A
Fuels	Coal, NG, TDF			A
Capacity (tons per day)	3,750			A
Current Control for PM	Baghouse			A
Current Control for SO2	Inherent Scrubbing			A
Current Control for NOx	SNCR			A
Exhaust Flow Rate (acfm)	306,708			B
Exhaust Temperature (F)	377			B
Exhaust Moisture (%)	8.2			B
	Air Pollutant	Units	Emission	
Allowable	PM10 (Filterable)	(tpy)	36.0	A
	PM10 (Condensable)	(tpy)	293.6	A
	PM10 (Total)	(tpy)	329.6	A
	SO2	(tpy)	943.4	A
	NOx	(tpy)	1,100.0	A
Allowable	PM10 (Filterable)	(lbs/ton)	0.1	Calculated
	PM10 (Condensable)	(lbs/ton)	0.4	Calculated
	PM10 (Total)	(lbs/ton)	0.5	Calculated
	SO2	(lbs/ton)	1.4	Calculated
	NOx	(lbs/ton)	1.6	Calculated
Allowable	PM10 (Filterable)	(lbs/hr)	8.2	Calculated
	PM10 (Condensable)	(lbs/hr)	67.0	Calculated
	PM10 (Total)	(lbs/hr)	75.3	Calculated
	SO2	(lbs/hr)	215.4	Calculated
	NOx	(lbs/hr)	251.1	Calculated
Uncontrolled	PM10 (Filterable)	(lbs/ton)	250.0	C
	PM10 (Condensable)	(lbs/ton)	67.0	A
	PM10 (Total)	(lbs/ton)	317.0	Calculated
	SO2	(lbs/ton)	1.4	D
	NOx	(lbs/ton)	4.2	A
Uncontrolled	PM10 (Filterable)	(lbs/hr)	39,062.5	Calculated
	PM10 (Condensable)	(lbs/hr)	10,473.7	Calculated
	PM10 (Total)	(lbs/hr)	49,536.2	Calculated
	SO2	(lbs/hr)	215.4	Calculated
	NOx	(lbs/hr)	656.3	Calculated
Uncontrolled	PM10 (Filterable)	(tpy)	171,093.8	Calculated
	PM10 (Condensable)	(tpy)	45,875.0	Calculated
	PM10 (Total)	(tpy)	216,968.8	Calculated
	SO2	(tpy)	943.4	Calculated
	NOx	(tpy)	2,874.4	Calculated

A - CDPHE, Regional Haze Second 10-year Planning Period, Reasonable Progress Four-Factor Analysis of Control Options for
B - GCC Rio Grande, ,Inc., Portland Cement Manufacturing Facility, Pueblo County, Colorado, Revised Initial Title V Operating
C - USEPA, AP42, Table 11.6-2 - Emission Factors for Portland Cement Manufacturing, January 1995.
D - Uncontrolled SO2 assumed to be same as allowable due to use of inherent scrubbing within kiln.

Air Pollutant	PM10 (Filterable)	PM10 (Condensable)	PM10 (Total)	SO2	NOx	Total
Allowable	36.0	293.6	329.6	943.4	1,100.0	2,373.0
Uncontrolled	171,093.8	45,875.0	216,968.8	943.4	2,874.4	220,786.5

	Reference	Original (2015)		Original (2021)	Reference	GCC Rio Grande	GCC Rio Grande
Location of New Catalytic Filters						After Baghouse	Replace Baghouse
Emissions Basis		Potential		Potential		Allowable	Uncontrolled
Capacity (tpd)	Quotation	700		700	2021 CDPHE	3,750	3,750
Current Flow (acfm)					Permit Application	306,708	306,708
Current Temperature (deg F)					Permit Application	377	377
Inlet Flow (acfm)	Quotation	96,745		96,745	Calculated	370,102	370,102
Inlet Temperature (deg F)	Quotation	550		550	Calculated	550	550
Inlet NOx (lbs/ton)	Quotation	18.0			Current Allowable	1.6	
Inlet SO2 (lbs/ton)	Quotation	4.0			Current Allowable	1.4	
Inlet PM (lbs/ton)	Quotation	1.2			Current Allowable	0.1	
Inlet NOx (tpy)	Calculated	2,299.5			Current Allowable	1,100	
Inlet SO2 (tpy)	Calculated	511.0			Current Allowable	943	
Inlet PM (tpy)	Calculated	153.3			Current Allowable	36	
NOx Removal (%)	IN vs OUT	90.0%			Same as Original	90.0%	
SO2 Removal (%)	IN vs OUT	75.0%			Same as Original	75.0%	
PM Removal (%)	IN vs OUT	95.8%			Same as Original	95.8%	
Outlet NOx (lbs/ton)	Quotation	1.8			Calculated	0.16	
Outlet SO2 (lbs/ton)	Quotation	1.0			Calculated	0.34	
Outlet PM (lbs/ton)	Quotation	0.1			Calculated	0.002	
Outlet NOx (tpy)	Calculated	230.0			Calculated	110.0	
Outlet SO2 (tpy)	Calculated	127.8			Calculated	235.9	
Outlet PM (tpy)	Calculated	6.4			Calculated	1.5	
Removed NOx (tpy)	Calculated	2,069.6			Calculated	990.0	
Removed SO2 (tpy)	Calculated	383.3			Calculated	707.6	
Removed PM (tpy)	Calculated	146.9			Calculated	34.5	
Removed NOx, SO2 and PM (tpy)	Calculated	2,599.7			Calculated	1,732.1	
Inlet NOx (lbs/ton)	Quotation	18.0		18.0	Uncontrolled (USEPA)		4.2
Inlet SO2 (lbs/ton)	Quotation	4.0		4.0	Current Allowable		1.4
Inlet PM (lbs/ton)	Quotation	1.2		1.2	Uncontrolled (USEPA)		250
Inlet NOx (tpy)	Calculated	2,299.5		2,299.5	Calculated		2,874.4
Inlet SO2 (tpy)	Calculated	511.0		511.0	Calculated		943.4
Inlet PM (tpy)	Calculated	153.3		153.3	Calculated		171,093.8
NOx Removal (%)	IN vs OUT	90.0%		90.0%	Same as Original		90.0%
SO2 Removal (%)	IN vs OUT	75.0%		75.0%	Same as Original		75.0%
PM Removal (%)	IN vs OUT	95.8%		95.8%	Same as Original		95.8%
Outlet NOx (lbs/ton)	Quotation	1.8		1.8	Calculated		0.42
Outlet SO2 (lbs/ton)	Quotation	1.0		1.0	Calculated		0.35
Outlet PM (lbs/ton)	Quotation	0.1		0.1	Calculated		10.42
Outlet NOx (tpy)	Calculated	230.0		230.0	Calculated		287.4
Outlet SO2 (tpy)	Calculated	127.8		127.8	Calculated		239.5
Outlet PM (tpy)	Calculated	6.4		6.4	Calculated		7,128.9
Removed NOx (tpy)	Calculated	2,069.6		2,069.6	Calculated		2,586.9
Removed SO2 (tpy)	Calculated	383.3		383.3	Calculated		703.9
Removed PM (tpy)	Calculated	146.9		146.9	Calculated		163,964.8
Removed NOx, SO2 and PM (tpy)	Calculated	2,599.7		2,599.7	Calculated		167,255.7
Capital Costs		Original (2015)	Inflation	Original (2021)	Adjustment Method	GCC Rio Grande	GCC Rio Grande
Location of New Catalytic Filters						After Baghouse	Replace Baghouse
Emissions Basis						Allowable	Uncontrolled
Complete System Equipment and Installation		$12,159,935	1.15	$13,983,925	Six-Tenths by Inlet Flow	$31,278,404	$31,278,404
Capital Recovery Factor (CRF)	CRF (20 yrs, 3.25%)	0.06878	CRF (20 yrs, 3.25%)		CRF (20 yrs, 3.25%)	0.06878	0.06878
Annualized Capital Cost		$836,360				$2,151,329	$2,151,329
Operating Costs							
Electricity		$188,953	1.15	$217,296	Ratio by Inlet Flow	$831,274	$831,274
19% Aqueous Ammonia		$665,665	1.15	$765,515	Ratio by Inlet NOx	$366,195.36	$956,893
Hydrated Lime		$361,810	1.15	$416,082	Ratio by Inlet SO2	$768,162.99	$768,163
Labor for Operation and Maintenance		$69,213	1.15	$79,595	Six-Tenths by Inlet Flow	$178,033	$178,033
Natural Gas for Reheating Flue Gas						$1,854,147	$0
Annual Operating Costs		$1,285,641				3,997,812	2,734,363
Combined Capital and Operating Costs							
Capital Costs		$12,159,935				$31,278,404	$31,278,404
Annual Capital Costs		$836,360				$2,151,329	$2,151,329
Annual Operating Costs		$1,285,641				$3,997,812	$2,734,363
Annual Capital and Operating Costs		$2,122,001				$6,149,141	$4,885,692
Inlet NOx (tpy)		2,300				1,100	2,874
Inlet SO2 (tpy)		511				943	943
Inlet PM (tpy)		153				36	171,094
Inlet NOx, SO2 and PM (tpy)		2,964				2,079	174,912
Outlet NOx (tpy)		230				110	287
Outlet SO2 (tpy)		128				236	240
Outlet PM (tpy)		6				2	7,129
Outlet NOx, SO2 and PM (tpy)		364				347	7,656
Removed NOx (tpy)		2,070				990	2,587
Removed SO2 (tpy)		383				708	704
Removed PM (tpy)		147				35	163,965
Removed NOx, SO2 and PM (tpy)		2,600				1,732	167,256
Cost Effectiveness ($ per ton of NOx removed)		$1,025				$6,211	$1,889
Cost Effectiveness ($ per ton of total removed)		$816				$3,550	$29

Notes:

Complete System Equipment and Installation includes: emission control system, controls, infrastructure, engineering design and project management, installation, services, batch recycle system, ammonia tank shelter.

Inflation multiplier from November 2015 to August 2021 = 1.15 - https://www.bls.gov/data/inflation_calculator.htm

Capital Recover Factor based on lifetime of operation and % interest from DOE, Four-Factor Analysis, https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

Natural Gas for Reheating Flue Gas to 550 F

Start Temp	(deg F)	377
Start Flow	(acfm)	306,708
Inlet Temp	(deg F)	550
Inlet Flow	(acfm)	370,102
Inlet Flow	(scfm)	193,479
Inlet Flow	(lbs/min)	14,511
Start h	(btu/lbs)	200.83
Inlet h	(btu/lbs)	243.48
Change h	(btu/lbs)	42.65
Fuel Required	(btu/hr)	37,133,434
Fuel Required	(therms/hr)	371.3
Nat Gas	($/therm)	0.57
Nat Gas	($/yr)	$1,854,147

Appendix B

CDPHE Four-Factor Analysis

Regional Haze Second 10-year Planning Period Reasonable Progress Four-Factor Analysis of Control Options for GCC Rio Grande – Pueblo Cement Plant

August 2021

For the second Regional Haze 10-year planning period, Colorado evaluated all stationary sources in the state with oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and particulate matter (PM) emissions over 25 tons per year (TPY) to determine which sources should be evaluated for potential additional emission controls depending on proximity to Class I areas (CIAs). Sources were included in the Reasonable Progress (RP) analysis if their total emissions of NO_x, SO_2, and PM, in TPY, divided by distance to the nearest CIA, in km, ("Q/d") was greater than 10, based on 2014 National Emissions Inventory (NEI) emissions. In Colorado, sources with a Q/d > 10 are considered potential contributors to CIA visibility impairment and are subject to the four-factor review process. Although a facility may have installed controls, changed fuel sources, or made other operational changes since 2014 that have reduced emissions, these sources are still subject to evaluation. For all RP sources, the four factor analyses are conducted using more current baseline emissions, typically 2016-2018 actual emissions. In determining RP under the Regional Haze program, states must consider the four factors explicitly set forth in the Clean Air Act, which are:

(1) costs of compliance,
(2) time necessary for compliance,
(3) energy and non-air quality environmental impacts of compliance, and
(4) remaining useful life.

The GCC Pueblo cement plant has a Q/d = 12.67. Accordingly, the GCC plant is subject to the RP four-factor review process. Great Sand Dunes National Park is the nearest Class I Area to GCC and is 85.3 km (53.0 miles) from the GCC Pueblo plant. GCC was not analyzed during the first Regional Haze planning period.

For the purposes of evaluating RP, the Division elected to focus its analysis on those individual emission units with actual baseline emissions (2016 - 2018 average emissions) of NO_x, SO_2, or PM_{10} equal to or exceeding 10 TPY. The Division established a *de minimis* threshold to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

Prior to the application of the four statutory factors, the Division followed a process similar to assessing the application of the Best Available Control Technology (BACT), by identifying the available emissions control technologies and then determining if they were technically and economically feasible.

I. Source Description

Facility AIRS ID:	101-0252
Owner/Operator:	GCC Rio Grande
Source Type:	Portland Cement Manufacturing
SCC:	305-006-23 (Kiln), 305-006-14 (Clinker Cooler)

305-006-09 (Primary Crusher)
Kiln Type: Preheater/Precalciner Kiln

The GCC facility manufactures Portland cement and is located in Pueblo, Colorado, about 53 miles from Great Sand Dunes National Park. The facility is located in an attainment area for all criteria pollutants.

The GCC Pueblo kiln is the newest Portland cement plant in Colorado and is a modern preheater/precalciner that is much more energy efficient than older kiln designs. This design is much more energy efficient than earlier wet cement kilns which combusted large quantities of fuel to boil off the water in the slurry. It's also more energy efficient than long dry kilns, including the modified long-dry kiln at the CEMEX Lyons facility. The GCC kiln utilizes a 5-stage single string preheater and precalciner where most of the fuel is fired. This requires less overall fuel, resulting in lower emissions of NO_x, SO_2, and PM.

The permitted kiln production rate is 3,750 tons per day of clinker, and on average yields approximately 130 tons of clinker per hour. The kiln is the main source of PM_{10} and NO_x emissions, but its SO_2 emissions are below the 10 TPY de minimis threshold. The clinker cooler is the only other significant sources of visibility impairing PM_{10}, but does not emit SO_2 or NO_x.

Process Description:

The basic process of producing Portland cement plant involves producing a raw meal consisting of quarried materials, including limestone (primarily $CaCO_3$, calcium carbonate) and clay (which contains silicate minerals and aluminum oxides), along with other ingredients such as sand (primarily SiO_2, silicon dioxide) and scale (iron oxides). These raw meal ingredients are finely ground and mixed in various ratios depending on the desired final cement product. This raw meal is heated to very high temperatures in a rotary kiln to form alite ($Ca_3O \cdot SiO_4$) which clumps together in nodules called clinker, the primary component of Portland cement. In this heating process, NO_x is produced from the high combustion temperatures, SO_2 is produced from sulfur in the coal and sulfur-containing compounds in the limestone, and CO_2 is produced from the fuel combustion and the decomposition of calcium carbonate into calcium oxide and carbon dioxide ($CaCO_3 \rightarrow CaO + CO_2$). The clinker is cooled, combined with other products, such as gypsum ($CaSO_4 \cdot 2H_2O$), and ground to produce a specific Portland cement formulation.

In the case of the GCC Pueblo facility, the process begins with extracting limestone and other raw materials from the co-located quarry, and processing them through a primary crusher at the quarry. Water injection is used to drill blast holes for explosives and sequential blasting is used to minimize emissions for the blasting operations. The primary crusher is mobile and is positioned to minimize transport distance of material to reduce particulate emissions. The crusher is also equipped with a baghouse to control PM emissions. The crushed material is transported to the limestone storage dome by a covered conveyor system. The material is then blended and transferred via another covered conveyor to raw material storage bins. This conveyor and the blending processes are controlled by baghouses.

These storage bins contain limestone and additive materials, such as sandstone and iron. The facility develops the raw material blend by weighing the limestone and additives on weigh scales and transferring these materials to the raw mill by covered conveyor. The raw mill mixes and crushes the materials and delivers the homogenized material to a raw meal storage silo. A conveyor then feeds the raw meal from the storage silo to the preheater/precalciner.

Pulverized coal from the coal mill is also fed to the preheater/precalciner, where it is fired. Some process gases from the kiln are used to dry the coal, while the remaining gases pass through the in-line raw mill. This helps conserve energy and the in-line raw mill acts as a scrubber for SO_2 and ammonia. The material leaving the preheater/precalciner is almost completely calcined as it enters the rotary kiln, which is located at a slight incline along its horizontal axis. The material travels towards the clinker discharge end where additional pulverized coal is fired for the clinkering process. The clinker is discharged from the kiln into the clinker cooler where it is cooled by air forced through the clinker bed by under-grate fans. Heated air from the clinker cooler is fed into the kiln as pre-heated combustion air, which improves the energy efficiency of the kiln. The cooled clinker is transferred to the clinker storage dome by a covered conveyor before being transferred by two covered conveyors to a clinker storage silo near the finish mill. Finish mill additives, such as gypsum, are delivered via truck or rail and transferred to an additive storage silo near the finish mill. Clinker and additives from the clinker storage silo and additive silo are fed to the finish mill which grinds the material to a fine powder to produce Portland cement. The Portland cement is stored in product silos and shipped via railcar or truck.

From an overall perspective, the manufacturing process can be viewed as two segments -- clinker production and cement production. The clinker storage allows the two processes to operate at different production rates. During periods of low demand for cement, clinker is accumulated. If cement is in very high demand, the clinker production can be supplemented by purchase of clinker from other sources. The overall result is the clinker production can operate at a relatively steady rate, while the cement production can operate in response to current or projected demands.

For sources identified through the above screening process as potentially impacting western Class I Areas, a *de minimis* threshold was established to focus technical emission control analysis on significant emission units where potential controls could provide a meaningful improvement in visibility. Emission points may include point or fugitive emissions, or both. Identified sources were asked to submit relevant four-factor information for all emission points with 2016 - 2018 average actual baseline emissions of NO_x, SO_2, and PM_{10} greater than or equal to 10 TPY. These points were evaluated to identify additional emissions controls to determine if additional emissions reductions are technically feasible and cost effective.

GCC submitted a Four-Factor Analysis for the Kiln (AIRS ID 039) and Clinker Cooler (AIRS ID 040) to the Division on October 30, 2019 with additional information submitted on March 27, 2020 and May 19, 2020.

The emission points potentially subject to evaluation at GCC Pueblo plant are shown in Table 1. Emission points with permitted emissions of less than 10 TPY of NO_x, SO_2 or PM_{10} were excluded.

Table 1: GCC Emission Points

AIRS Point	Description	Emission Type
039	Kiln	Point
040	Clinker Cooler	Point
069	Quarry Crusher Engine	Point

Table 2 lists the permitted and actual emissions for all units with permitted or actual emissions over 10 TPY. Kiln (039) and Clinker Cooler (040) emissions are the 2016-2018 averages reported in the four factor analysis submitted by GCC. Actual emissions for the Quarry Crusher Engine (069) are based on the average of 2016 and 2017 emissions reported on 2017 and 2018 APENs submitted to the Division.

Table 2: GCC Permitted and Average Annual Emissions

Point	Permitted PM_{10} (TPY)	Actual PM_{10} (TPY)	Permitted SO_2 (TPY)	Actual SO_2 (TPY)	Permitted NO_x (TPY)	Actual NO_x (TPY)
039 *	36.01 (F) 293.56 (C)	11.3 (F) 99.0 (C)	943.4	*1.1*	1,100.0	915.2
040 **	33.92	27.9	*N/A*	*N/A*	*N/A*	*N/A*
069	*N/A*	*0.8*	*6.3*	*5.2*	*19.3*	*5.9*

*The kiln PM limit marked with (F) is for filterable emissions and the PM limit marked with (C) is condensable emissions. GCC is the only Colorado cement kiln with a limit on condensable particulate matter.

**The clinker cooler only emits particulates, thus there are no SO_2 or NO_x permit limits or actual emissions.

As shown in Table 2, the actual NO_x, PM_{10}, and SO_2 emissions for the Quarry Crusher Engine (069) are below the 10 TPY threshold, and the engine will not be evaluated further. The actual SO_2 emissions for the Kiln (039) are below 10 TPY, so this pollutant will not be analyzed for the kiln. This analysis will focus on PM_{10} and NO_x emissions for the Kiln (039) and PM_{10} emissions for the Clinker Cooler (040). The kiln is the primary source of visibility impairing pollutants including NO_x and PM_{10}. The clinker cooler is another significant source of PM_{10} emissions.

II. Source Controls

Kiln (AIRS 039)

The GCC Pueblo kiln fires primarily low sulfur, high BTU coal from mines in Colorado. Coal specifications for 2018 are listed in Table 3. The kiln is also permitted to fires natural gas, tire-derived fuel (TDF), and many alternative, non-hazardous waste fuels. However, the kiln only uses natural gas for startup and primarily fires coal. When available, the kiln is fired with coal combined and some TDF which can reduce NO_x emissions. The kiln is permitted to fire a maximum of 198,418 TPY of fuel (coal and TDF). There is a facility-wide limit of 381,373 MMBtu/yr of natural gas which is used for the finish mill heater and for kiln startup. APENs submitted for the kiln do not provide an exact heat content for the natural gas, but designate it as pipeline natural gas, which typically has a heat content around 1,020 MMBtu/MMscf. The APEN also does not list the sulfur content of the natural gas, but pipeline natural gas is extremely low in sulfur.

Table 3: Coal Specifications (2018 APEN)

	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Kiln	8,000-12,500	0.65	18

Table 4 depicts technical information for the GCC Pueblo kiln.

Table 4: Pueblo Kiln RP-eligible Emission Controls and Reduction (%)

	Portland Cement Kiln

Placed in Service	2008
Description	Preheater/precalciner kiln with 5-stage, single string preheater
Air Pollution Control Equipment	SO_2 -Inherent Scrubbing of the Cement Process in the Kiln and the In-line Raw Mill PM/PM_{10} - 2 Baghouses (Main Kiln, Coal Mill) NO_x - Selective Non-Catalytic Reduction
Emissions Reduction (%)	SO_2 - 99.99% * PM / PM_{10} - 99.99% / 99.99% ** NO_x - 53.6% ***

*SO_2 reductions based on actual SO_2 emissions measured by CEMS and input sulfur content. The sulfur input to the kiln is estimated as (Annual tons coal * Weight fraction of sulfur in coal) + (Annual tons of raw meal * Weight fraction of sulfur in raw meal).
**PM/PM_{10} reductions based on stack tests.
***NO_x reductions are based on the uncontrolled AP-42 emission factor for a preheater/precalciner kiln (4.2 lb/ton of clinker) compared to the 2016-2018 average 30-day emission rate (1.95 lb/ton of clinker). The Pueblo kiln was built with an SNCR, so the Division cannot compare pre-control and post-control emissions.

The source has not announced a closure date for the kiln, so the Division will assume a remaining useful life of 20 years for any control cost analysis.

Clinker Cooler (AIRS 040)

The clinker cooler employs a baghouse to control particulate emissions. Baghouses are typically a top-tier control for PM.

III. Reasonable Progress Evaluation of GCC Pueblo plant

a. SO_2

SO_2 emissions for the Kiln (039) are below the 10 TPY de minimis threshold and thus were not evaluated for SO_2 controls.

b. Filterable Particulate Matter (PM10)

Step 1: Identify All Available Technologies

Kiln (AIRS 039)

Filterable and condensable PM_{10} emissions from the kiln are greater than the 10 TPY threshold. As noted earlier, the GCC Pueblo kiln is the newest unit in Colorado and the only kiln with a condensable PM_{10} limit. Filterable PM emissions are solid and liquid particles at stack conditions and are typically controlled with fabric filter baghouses or electrostatic precipitators (ESPs). Filterable PM emissions can be measured using EPA reference methods that capture by the particulate matter in the filter segment of a sampling train. Over 99.9% of these filterable emissions are captured by the existing fabric filter baghouse. Electrostatic precipitators are the primary alternative for reducing filterable PM and can achieve over 99.9% control efficiency on some sources. However, the high resistivity of cement kiln dust makes them less effective than baghouses for controlling PM emissions from Portland cement kilns.[1]

Condensable PM emissions are vapors at stack conditions, but quickly condense after exiting the stack. The condensable emissions consist of organics (VOCs) and inorganics (primarily ammonium salts). The 2012 permit modification request from GCC states that the organic content in the raw materials is less than 1% and the volatile content of the coal is also low, which suggests that most of the condensable PM emissions from the kiln are inorganic ammonium salts. These inorganic ammonium salts form when excess ammonia from the SNCR, known as ammonia slip, reacts with chlorides and sulfates from the raw materials and coal. The most effective control methods for condensable PM emissions are limiting the available supply of ammonia, chlorides, sulfates, and other compounds that can form PM. Reducing ammonia slip limits the available ammonia to form these salts. The chloride content of the raw materials is limited to avoid alkali chloride deposits building up in the kiln preheater and chloride levels are typically low in coal. Firing low sulfur coal reduces sulfur input to the kiln, but most SO_2 emissions result from pyrite and other sulfur contaminants in the limestone, which vary depending on the limestone source. The cement production process is very effective at scrubbing SO_2 unless high pyrite levels limit this inherent scrubbing process. Since the GCC Pueblo kiln has very low SO_2 emissions without the use of a scrubber, the Division concludes that the raw materials have very low pyrite levels. Therefore, the most effective way to minimize condensable PM emissions is to limit ammonia slip. The in-line raw mill not only provides raw materials for the kiln, it also acts as a scrubber to further reduce ammonia emissions. When the raw mill is operating, GCC operates the SNCR to comply with the NO_x permit limit. The raw mill operates continuously when the kiln is operating, except for downtime associated with the maintenance or malfunctions of the mill. If the raw mill is shut down for maintenance or due to a malfunction, the SNCR stops injecting ammonia into the kiln to avoid a spike in ammonia emissions that could lead to a visible plume that exceeds the opacity limit for the kiln.

The baghouse on the GCC Pueblo kiln is a top tier control for filterable PM emissions, and the facility effectively minimizes condensable PM emissions by limiting ammonia slip from the SNCR and using fuel and raw materials with low sulfate and chloride levels. The Division has not identified any additional controls or work practices that would improve upon the existing filterable and condensable PM controls.

Clinker Cooler (AIRS 040)

The clinker cooler uses fans to circulate cool, ambient air over the hot clinker exiting the kiln. As the ambient air absorbs heat it becomes hotter and this hot air is returned to the kiln which improves the kiln's energy efficiency by reducing the amount of fuel that needs to be fired to heat the kiln. Cooler air from later stages of the clinker cooler passes through a baghouse for PM control before exiting a separate stack. GCC reports emissions based on the results of a stack tests which are below a BACT limit of 0.01 gr/dscf (grains per dry standard cubic foot). GCC reports PM control efficiency of 99.99% on its APEN submittals to the Division, which is in line with baghouse control efficiencies for other processes. EPA notes that clinker cooler are typically controlled using fabric filter baghouses, though it provides emission factors for other potential controls such as Electrostatic Precipitators (ESPs).[2] Although ESPs may provide similar control efficiencies to baghouses, ESPs often require

[1] North Carolina DEQ. "Carolinas Cement Company: Control Technology Analysis." Page 10 of 102. April 2008.

[2] EPA. AP-42 Emission Factor for Portland Cement Manufacturing, pages 7 and 14. January 1995.

shutdowns for maintenance, whereas baghouses can be maintained while the cooler is operating. Because the existing baghouse achieves high control efficiency and can be maintained during operation, the Division has determined that the GCC Pueblo clinker cooler already has top tier PM controls and no new particulate control measures have been identified that would significantly upon the existing fabric filter baghouse.

Step 2: Eliminate Technically Infeasible Options

Kiln (AIRS 039)

The Division has determined that the currently operating PM/PM_{10} controls on the kiln perform better than any of the identified control technologies. Therefore, there are no remaining technically feasible options other than the existing controls in operation for the GCC Pueblo kiln.

Clinker Cooler (AIRS 040)

The Division has determined that the currently operating PM/PM_{10} controls on the clinker cooler perform better than any of the identified control technologies. Therefore, there are no remaining technically feasible options other than the existing controls in operation for the GCC Pueblo clinker cooler.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Kiln (AIRS 039)

Filterable PM_{10} emissions from the GCC kiln are reported based on a baghouse loading factor, but stack testing indicates that actual filterable emissions are much lower than the estimates based on the baghouse loading factor. Condensable PM_{10} emissions are reported based on emission factors determined through stack testing and approved by the Division. GCC reports the baghouses achieve 99.99% control efficiency on the APENs submitted to the Division, and the Division has not identified other control options with higher control efficiencies.

Clinker Cooler (AIRS 040)

Filterable PM_{10} emissions from the GCC clinker cooler are reported based on a baghouse loading factor, but stack testing indicates that actual filterable emissions are much lower than the estimates based on the baghouse loading factor. GCC reports the baghouses achieve 99.99% control efficiency on the APENs submitted to the Division, and the Division has not identified other control options with higher control efficiencies.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

Kiln (AIRS 039)

There are no associated costs of compliance since no options other than continuing to operate the existing PM controls on the kiln are considered technically feasible.

Clinker Cooler (AIRS 040)

There are no associated costs of compliance since no options other than continuing to operate the existing PM controls on the clinker cooler are considered technically feasible.

Factor 2: Time Necessary for Compliance

Kiln (AIRS 039)

There is no additional time required for compliance since no options other than continuing to operate the existing PM controls on the kiln are considered technically feasible.

Clinker Cooler (AIRS 040)

There is no additional time required for compliance since no options other than continuing to operate the existing PM controls on the clinker cooler are considered technically feasible

Factor 3: Energy and Non-Air Quality Impacts

Kiln (AIRS 039)

There are no specific energy and non-air quality impacts associated with the continued operation of the particulate controls on the kiln.

Clinker Cooler (AIRS 040)

There are no specific energy and non-air quality impacts associated with the continued operation of the particulate controls on the clinker cooler.

Factor 4: Remaining Useful Life

Kiln (AIRS 039)

GCC has not announced a closure date for the Pueblo kiln or its associated limestone quarry. Therefore, the Division assumes that the kiln will remain in operation for at least 20 years. Because no additional control options are considered technically feasible, remaining useful life does not impact cost estimates for additional controls.

Clinker Cooler (AIRS 040)

GCC has not announced a closure date for the Pueblo kiln or its associated limestone quarry. Therefore, the Division assumes that the clinker cooler will remain in operation for at least 20 years. Because no additional control options are considered technically feasible, remaining useful life does not impact cost estimates for additional controls.

Determinations

Kiln (AIRS 039)

Based upon its consideration of the four factors summarized herein and detailed in Appendix C, the Division recommends that RP for PM_{10} is the following:

1) The following existing PM_{10} emission limits shall remain in effect for this planning period:
   Kiln: 36.01 TPY (filterable, 12-month rolling average)
   293.56 TPY (condensable, 12-month rolling average)

The state assumes that the RP emission limits can be achieved through continued operation and maintenance of the existing fabric filter baghouse, good combustion practices, and good operation of the SNCR to minimize NO_x and excess ammonia emissions. The Division has determined that these limits are achievable without additional capital investment through the four-factor analysis.

Clinker Cooler (AIRS 040)

Based upon its consideration of the four factors summarized herein and detailed in Appendix C, the Division recommends that RP for PM_{10} is the following:

1) The following existing PM_{10} emission limit shall remain in effect for this planning period:
   Clinker Cooler: 33.92 TPY (12-month rolling average)

The state assumes that the RP emission limits can be achieved through continued operation and maintenance of the existing fabric filter baghouse. The Division has determined that this limit is achievable without additional capital investment through the four-factor analysis.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Kiln (AIRS 039)

As noted earlier, the GCC Pueblo facility was not evaluated during the first round of Regional Haze because it had undergone a pre-construction PSD review and was recently constructed with many technologies to reduce NO_x including: an energy efficient multi-stage preheater, low-NO_x calciner, low-NO_x Burners (LNBs) with indirect firing, staged combustion (SCC), and a Selective Non-Catalytic Reduction (SNCR) unit. Table 5 shows the current limits and actual emissions for the 2016-2018 baseline period. As shown, the kiln is in compliance with the 12-month total and lb/ton of clinker limits. As shown in Table 4, the GCC Pueblo kiln achieves approximately 53.6% lower NO_x emissions than a baseline uncontrolled preheater/precalciner kiln using the NO_x controls listed above, as well as firing tire-derived fuel (TDF), when available. Unlike the CEMEX Lyons and Holcim Florence kilns, the GCC Pueblo kiln does not currently have a 30-day rolling average NO_x limit. The Division will discuss potential emission limit changes later in this analysis.

Table 5: Kiln Limits vs. Actual Emissions

	Limit	2016-2018 Actual Average [Min - Max]
12-Month Rolling Total (TPY)	1,100.0	915.18 [816.6 - 996.7]
12-Month Rolling Average (lb/ton of clinker)	2.32	1.97 [1.82 - 2.11]
30-day Rolling Average (lb/ton of clinker)	N/A	1.95 [1.61 - 2.70]

The Division reviewed EPA's RACT/BACT/LAER Clearinghouse (RBLC) for similar Portland cement kilns for the most recent 20 years and the EPA Menu of Control Measures for additional or improved potential control options. Most of the recently permitted kilns are multi-stage preheater/precalciner designs that are comparable to the GCC Pueblo kiln. However, cement kiln emissions are highly dependent on fuel and raw material composition, in addition to the general kiln design. The RBLC determinations provide an indication of the achievable emission rates at Portland cement kilns that are subject to the latest NSPS. Based on the startup date for the GCC Pueblo kiln, it is not subject to the NSPS limit of 1.50 lb/ton of clinker. The lowest emission permitted emission rate listed in the RBLC was the Universal Cement Plant in Illinois which was permitted in 2010 at 1.2 lb/ton of clinker. Illinois EPA deemed this to meet LAER and was achievable using a combination of staged combustion and SNCR. This facility was never constructed. The CEMEX North Brooksville Kiln 3 was permitted in 2007 at 1.5 lb/ton of clinker with SNCR <u>or</u> SCR <u>or</u> a combination of these two. The permit was withdrawn and this kiln was never constructed. Other determinations range from 1.5 lb/ton to 2.65 lb/ton of clinker and utilize SNCR, often combined with indirect firing, low-NOx burners, and staged combustion, all of which are utilized in the GCC Pueblo kiln.

The following kiln NO_x controls were considered, if technically feasible, for this planning period:

-Fuel Substitution - Firing Tire-Derived Fuel (TDF)
-Selective Non-Catalytic Reduction + Low- NO_X Burners (SNCR + LNB)
-Staged and Controlled Combustion (SCC)
-Selective Catalytic Reduction (SCR)

Step 2: Eliminate Technically Infeasible Options

Kiln (AIRS 039)

Fuel Substitution: Fuel substitution for Portland cement kilns involves firing a combination of fossil fuels and alternative fuels, such as non-hazardous waste and tire-derived fuel (TDF). In principal, converting a cement kiln to full natural gas combustion would significantly reduce SO_2 and PM_{10} emissions, but would not significantly reduce NO_X emissions.[3] However, a natural gas flame in the main kiln burner may not sufficiently dissipate heat which can reduce clinker production and may require raw meal reformulation to maintain product quality.[4] The lower heat transfer of a natural gas flame in the main kiln can also lead to higher temperatures that increase thermal NO_x production.[5] Although few kilns use natural gas as the primary fuel, many kilns, including the GCC Pueblo facility, fire natural gas at startup to minimize emissions while heating up the kiln. Discussions with other Colorado kiln operators confirmed that operating a kiln entirely on natural gas may require extensive modifications to the kiln design and controls and result in lower production capacity. When used correctly, alternatives fuels with high energy content (Btu/lb), such as TDF, can help safely dispose of waste tires and reduce NO_x emissions from the kiln. However, the kiln operator needs to maintain proper combustion conditions to avoid emissions increases from firing TDF. GCC is currently firing the kiln with low sulfur coal, as indicated in Table 3, natural gas for startup, and TDF, when available.

In 2002, CEMEX conducted a stack test with the long-dry kiln firing a combination of coal and TDF. The stack tests on this long-dry kiln suggested 24.4% reductions in NO_X emissions from firing TDF without exceeding the standards for any other criteria pollutants or hazardous air pollutants.[6] However, the reductions are highly kiln dependent and also dependent on the fuel being replaced. Simulations for fuel switching at Lafarge's Brookfield cement plant in Nova Scotia indicated that switching from a 100% blend of high sulfur coal and pet coke (50-50 blend, 3.5% overall weight % sulfur) to 30% TDF and 70% coal/pet coke blend would reduce fuel NO_x by 23%.[7] In contrast, EPA expects that firing TDF can reduce NO_x emissions by 33% on average, but in rare cases kilns may see NO_x increases around 20% as well as increases of other criteria pollutants. Overall, the Division expects that firing TDF can reduce NO_x emissions.

GCC is already permitted to fire TDF and utilizes the fuel when available. Colorado has the largest waste tire piles, known as monofills, in the country and combusting them at high heat

[3] EPA. "Alternative Control Techniques Document Update - NOx Emissions from New Cement Kilns." Page 44 of 129. November 2007.
[4] IEEE Cement Industry Technical Conference. "From coal to natural gas: Its impact on kiln production, Clinker quality and emissions." 2013.
[5] EPA. "Alternative Control Techniques Document Update - NO_x Emissions from New Cement Kilns" November 2007.
[6] BART Analysis for CEMEX Lyons Cement Plant. Page 21
[7] Dalhousie University. "Use of scrap tires as an alternative fuel source at the Lafarge cement kiln, Brookfield, Nova Scotia, Canada" Page 23. July 21, 2015.

in a cement kiln not only reduces NO_x emissions from the kiln, it can also reduce the likelihood of large uncontrolled, monofill fires that release thick black clouds of smoke due to poor combustion conditions.[8] In order to use these tires on a consistent basis, cement manufacturers need a nearby monofill and may require government incentives to cover the cost of shredding the tires and transporting them to the facility, especially if the monofill is far from the cement plant. In recent years, GCC has struggled to identify a large, consistent supply of tires near the Pueblo area, and funding for Colorado's waste tire program has varied from year to year. Due to these issues, the Division considers it infeasible to mandate a minimum amount of annual TDF usage considering that GG is already permitted to use a significant amount of TDF as fuel. As more TDF becomes available, GCC will use more TDF. Therefore, a limit requiring a certain amount of TDF is not necessary. The Division will continue to work with GCC to evaluate the facility's future use of TDF and look for opportunities to reduce kiln emissions and Colorado's large stockpile of waste tires. Since TDF usage is currently permitted and utilized, when available, the Division will not analyze this option further.

SNCR: Fuel substitution, which is discussed above, affects the combustion process, while SNCR and SCR are post-combustion controls that treat the combustion products. Both controls inject an ammonia or urea reagent into the flue gas to convert NO_x to molecular nitrogen (N_2). These reactions require higher temperatures in an SNCR (1,600 to 2,000°F), compared to SCR (450 to 800°F), and provided lower control efficiency. SNCR systems typically have lower capital costs than an SCR, but the operating costs are higher due to high reagent use. SNCR design requirements and performance are discussed in more detail below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Above this temperature range, the NH_3 is oxidized to NO_x, thereby increasing NO_x emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH_3 may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH_3 could be delivered to the kiln system through the use of anhydrous NH_3, or an aqueous solution of ammonium hydroxide [NH_3(aq)]or urea [$CO(NH_2)_2$]. A concern about application of SNCR technology is the breakthrough of unreacted NH_3 as "ammonia slip" and its subsequent reaction in the atmosphere with SO_2, sulfur trioxide (SO_3), hydrogen chloride (HCl) and/or chlorine (Cl_2) to form a detached plume of PM_{10}-$PM_{2.5}$. In addition to reacting with SO_x and chloride emissions from the kiln, the unreacted ammonia could react with NO_x or SO_x from other sources to form visibility impairing ammonium nitrate or ammonium sulfate, respectively. As discussed earlier, the in-line raw mill at the GCC Pueblo kiln is an important part of the emission control system that helps minimize unreacted ammonia emissions and the raw mill is operating when the kiln is operating, except for planned weekly mill maintenance and unexpected mill malfunctions.

The existing NO_x controls on the GCC Pueblo kiln, which include an SNCR, currently achieve average annual NO_x emissions of 1.97 lb/ton of clinker, which represents a 53% reduction in NO_x emissions, compared to an uncontrolled preheater/precalciner kiln. This agrees with EPA's SNCR performance data which indicates that the technology can achieve NO_x reductions

[8] Booth, Michael. "Colorado's tire dumps were supposed to be gone by now. They grew instead." Colorado Sun. January 19, 2021.

of 20 - 90%, with 50% as a reasonable long-term reduction.[9] It's important to note that achieving high NO_x (>60%) control efficiencies with an SNCR often results in high ammonia slip, as discussed in EPA's ACT for NO_x emissions from cement kilns.[10] As explained in the PM section above, ammonia slip from the SNCR can react with chlorides and sulfates from the raw materials and coal to form condensable PM emissions. In order to minimize both NO_x and condensable PM emissions, the SNCR is operated to limit excess ammonia injection and the in-line raw mill acts as a scrubber to further reduce ammonia emissions, when the mill is operating. If the raw mill is shut down for maintenance or due to a malfunction, the SNCR temporarily stops to avoid a spike in ammonia emissions that could lead to a visible plume that exceeds the opacity limit for the kiln. When the raw mill is restarted, the SNCR operates at higher ammonia injection rates to compensate for the higher NO_x emissions during the raw mill downtime, and to comply with the 1,100 TPY and 2.32 lb/ton of clinker limits. As discussed earlier, the SNCR on the GCC Pueblo kiln operates around 95% of the hours in a week, but is permitted on an "as-needed" basis to allow for the 8-hour weekly maintenance of the in-line raw mill. The kiln was initially permitted with a minimum required uptime for the SNCR, but modeling indicated that the increased ammonia emissions from the kiln would require a higher condensable PM limit. The permit was revised to reflect the "as-needed" SNCR operation to avoid a large increase in PM emissions for a limited reduction in NOx emissions. The Division still believes that requiring GCC Pueblo to operate the SNCR on a continuous basis without an allowance for maintenance of the in-line raw mill would increase ammonia slip and visibility-impairing condensable PM emissions. Given that the GCC Pueblo plant is located in an ozone attainment area and less than 10 miles from the populated Pueblo community, the Division does not believe the potential NO_x reduction is a valid trade-off for likely increases in ammonia emissions. Therefore, it is not recommending a change to continuous SNCR operations.

The Division and GCC have not identified any potential upgrades to the existing SNCR that would significantly improve its performance. The Division will continue to monitor the long-term performance of the SNCR and will work with GCC to ensure that the kiln achieves the maximum NO_x control at a reasonable cost without significant increases in PM or other emissions. SNCR changes will not be analyzed in further detail.

SNCR + LNB: Low-NO_x burners (LNB) are designed to create a multi-stage combustion process with less excess oxygen. LNBs create a fuel-rich primary combustion zone where the low oxygen levels result molecular nitrogen (N_2) formation, rather than NO_x, from nitrogen in the combustion air and fuel-bound nitrogen. The GCC kiln currently employs low-NO_x burners with the SNCR discussed above to achieve 53% NO_x reductions. The Division has not identified additional upgrades to the existing LNBs that would achieve additional NO_x reductions.

SCR: SCR systems are the most widely used post-combustion NO_x control technology for coal-fired and natural gas-fired boilers. However, the technology has seen very little use at US cement kilns. In SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent when passed over an appropriate amount of catalyst. The NO_x and ammonia react to form nitrogen and water vapor, as described in the equations in the SNCR section. The principal is similar to SNCR, which is currently installed at the GCC Pueblo kiln, but the SCR catalyst reduces the required flue gas temperature necessary for the NO_x

[9] EPA. National Emissions Standard for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry - Cost Environmental Impact Data. August 6, 2010.
[10] EPA. "Alternative Control Techniques Document Update - NOx Emissions from New Cement Kilns." Page 17 of 129. November 2007.

reducing reaction. An optimized SCR design will provide the maximum level of NO_x reduction while maintaining low ammonia slip that could harm health and impair visibility. Detached plumes are possible with SCR, but less common than with SNCR.

EPA's ACT for NO_x emissions from cement kilns discusses SCR control for cement kilns. The document notes the SCR operating range depends on the catalyst material, and can range from 450°F to 800°F for base metal catalysts, to over 1,100°F for precious metal catalysts, though these are typically much more expensive. There are numerous challenges to operating an SCR on a cement kiln, including plugging and erosion of the catalyst caused by the high dust produced in the kiln. According to Benson[11], alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (*See also* Nicosia *et al.*, 2008, and Strege *et al.*, 2008). Calcium, in the form of limestone, is a staple of cement production, though sodium, potassium, and magnesium levels are tightly controlled in the raw meal to prevent swelling or cracking of the concrete. Also, alkalies and sulfur can potentially poison the catalyst.[12] The low levels of sulfur in the raw materials and inherent sulfur control of the cement process significantly reduces sulfur levels, but alkali levels could potentially impact the catalyst.

The two biggest remaining concerns for a potential SCR system at the GCC Pueblo facility are dust and site-specific design requirements. SCR systems can often be installed on coal-fired boilers in a "high dust" configuration, upstream of the particulate control device. However, this may not be feasible for cement kilns, including the GCC Pueblo kiln, due to the potential for catalyst plugging and erosion caused by the very high dust levels in a kiln. Therefore, the SCR would need to be installed in a "low dust" configuration, downstream of the baghouse. Unfortunately, the post-baghouse flue gas temperature has dropped below the ideal range for SCR operation and it would require reheating with a duct burner or heat exchanger using natural gas or coal. This reheating increases upfront capital costs for the system, ongoing operating and maintenance costs for fuel and burner/heat exchanger maintenance, and results in additional NO_x emissions that increase inlet NO_x levels to the SCR system. Lastly, at the time of the BART analysis, three cement kilns in Europe had installed SCR systems. Two were newer preheater kilns and the third was a smaller, traveling grate kiln. Although these kilns could achieve 80-90% NO_x reductions, it was unclear how well these results would translate to US cement kilns. As noted in the CEMEX BART analysis, the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available.[13] A search of the RBLC indicates that the CEMEX North Brooksville Kiln #3 selected SNCR, SCR, or a combination of the two technologies to meet BACT for NO_x control. However, this permit was withdrawn, and this kiln was never constructed. Due to a lack of any commercially available SCR units on US cement kilns, the Division concluded that SCR was not technically feasible for retrofit on existing cement kilns at that time.

Since the CEMEX BART analysis was conducted, there has been a single US cement kiln, the Lafarge Joppa Kiln 1 in Illinois that installed an SCR for NO_x Control. Joppa Kiln 1 is a long dry kiln with LNB and a hot electrostatic precipitator (ESP) for PM control. The SCR is installed downstream of the ESP in a "low dust" arrangement. This SCR was required as part of 2010

[11] Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005).
[12] Strege, J. et al., "SCR deactivation in a full-scale co-fired utility boiler, Fuel 87" (2008)
[13] Schreiber, R, *et al* "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry", (2006)

consent decree (CD) with Lafarge that covered kilns at 13 facilities in 13 states.[14] Joppa Kiln 1 was the only kiln required to install an SCR. Lafarge was required to conduct a 12-month optimization study to determine the kiln's emission limit. The emission limit was ultimately set at 3.21 lb/ton of clinker using the formula prescribed in the consent decree: Limit = $\mu + 1.645^*\sigma$, where μ is the mean of the 30-day rolling averages during the 12-month optimization period and σ is the standard deviation of the 30-day rolling averages. According to the Final Demonstration Report for the SCR, the mean was 1.99 lb/ton of clinker and the standard deviation was 0.75 lb/ton of clinker, resulting in an 80% reduction in NO_x compared to the baseline levels.[15] The average 30-day emission rate from Joppa Kiln 1 (1.99 lb/ton of clinker) using LNB + SCR is slightly higher than the current emissions from GCC Pueblo (1.95 lb/ton of clinker) with LNB + SNCR. Also, the NO_x emissions from Joppa Kiln 1 have much greater variability, as indicated by the standard deviation of 0.75 lb/ton of clinker, which is about 3.5 times larger than GCC Pueblo's standard deviation of 0.21 lb/ton of clinker. In addition, cost information for the Joppa SCR is not publicly available, so it's not possible to compare the cost effectiveness to the existing SNCR at GCC Pueblo.

Since the Joppa consent decree in January 2011, EPA has issued nine consent decrees against cement manufacturers, as shown in Table 6 below. This includes the CEMEX Lyons facility in Colorado. All of the facilities were required to install an SNCR to comply with NO_x limits, except for Essroc Logansport Kiln 1 and Kiln 2 in Indiana, which are both long wet kilns that are not comparable to GCC Pueblo. Both Logansport kilns were required to conduct 4-month SCR pilot studies.[16] If the pilots were deemed successful, the kilns would operate the SCR going forward based on a NO_x limit established during the pilot studies. If the studies were deemed unsuccessful, the kilns would install SNCR with a NO_x limit determined by EPA. "Success" for the SCR pilot studies included reducing NO_x by at least 80% while maintaining ammonia slip below 10 ppm without negatively impacting product quality or kiln reliability. Essroc completed these SCR studies and submitted the report to EPA, but EPA rejected them. Essroc filed for dispute resolution and, as a result, EPA required Essroc to run a second SCR study and submit the performance reports to EPA. Prior to the start of the second SCR study, EPA required Logansport Kiln 1 and Kiln 2 to establish tighter emission limits, but neither kiln was required to permanently install an SCR. Ultimately, EPA, Essroc, and the State of Indiana required Logansport Kiln 2 to install a water injection system with a NO_x limit of 4.75 lb/ton of clinker, on a 30-day rolling average. Logansport Kiln 1 was required to install a water injection system and an SNCR, and conduct a study to establish a NO_x emission limit that is no less stringent than 4.75 lb/ton of clinker. The Division was unable to obtain a copy of either the initial or second SCR pilot studies, but has concluded that neither Kiln 1 nor Kiln 2 is currently operating an SCR. This leaves the Joppa kiln as the only US cement kiln still operating an SCR for NO_x control. Table 9 demonstrates that the limit of 1.85 lb/ton of clinker imposed by the CEMEX Lyons consent decree matched the lowest emission limit set by consent decree up to April 2013. Although GCC's annual limit of 2.32 lb/ton of clinker is higher than CEMEX's limit, the current requirements for the facilities are very different: the GCC Pueblo facility is located in an attainment area whereas CEMEX is an ozone nonattainment area, GCC's SNCR was installed for BACT not due to a consent decree, and CEMEX is not subject to condensable PM or ammonia slip limits, both of which allows CEMEX to operate at higher ammonia injection rates to achieve greater control efficiency. Other than the Lafarge Joppa kiln 1 in Illinois, no US cement kilns have installed and continue to

[14] EPA. Consent Decree: Lafarge North America, Inc, Lafarge Midwest, Inc, and Lafarge Building Materials, Inc. January 2010.

[15] LAFARGE - U.S. EPA Consent Decree Final Demonstration Report, Joppa Kiln 1. April 2015.

[16] EPA. Consent Decree: Essroc Cement Corp. December 2011.

operate an SCR for NO_x control based on a consent decree. As discussed earlier, the Joppa kiln has a much higher emission limit and more NO_x emission variability than nearly all recent consent decrees, including GCC Pueblo. All of the other consent decree limits are based on SNCR controls, as shown in Table 6.

Table 6: EPA Cement Manufacturer Consent Decrees after January 2010

Company Name	CD Date	# of Facilities Included in CD	# of Kilns Included in CD	NOx Limit (Control Tech)
CEMEX Fairborn	Feb 2011	1	1	1.85 lb/ton (SNCR)
CalPortland	Dec 2011	1	1	2.5 lb/ton (SNCR)
Essroc (now Lehigh Cement)	Dec 2011	6	9	1.85 - 4.75 lb/ton (SNCR) *
CEMEX Lyons	Apr 2013	1	1	1.85 lb/ton (SNCR)
Ash Grove	June 2013	9	13	1.5 - 8 lb/ton (SNCR)
Holcim/ St. Lawrence	July 2013	1	1	1.8 lb/ton (SNCR)
CEMEX	July 2016	5	7	1.5 - 5.3 lb/ton (SNCR)
Lonestar/Buzzi	Aug 2016	1	1	1.5 - 2.9 lb/ton (SNCR) **
Lehigh	Dec 2019	11	14	1.5 - 8.2 lb/ton (SNCR)

* Essroc Logansport was required to conduct SCR pilot studies on Kilns 1 and 2. The pilot study reports were rejected by EPA and the source and EPA ultimately agreed to install water injection on both kilns. Kiln 1 was also required to install an SNCR. Both kilns have limits of 4.75 lb/ton of clinker.
** The two emission rates at the Lonestar facility are for firing waste (1.5 lb/ton) and not firing waste (2.9 lb/ton).

The Division also reviewed the RBLC to look for instances where SCR has been approved. As discussed earlier, the CEMEX North Brooksville Kiln 3 in Florida was permitted in 2007 with SNCR, SCR, or a combination of the two, but the permit was withdrawn and the kiln was never built. The only LAER determination listed in the RBLC was the Universal Cement plant in Illinois that was permitted at 1.2 lb/ton of clinker using staged combustion and SNCR, not SCR. LAER determinations seek the lowest achievable emission rate without consideration of cost, a more stringent standard than the BACT determination for GCC Pueblo, and SCR has not been selected as LAER for NO_x emissions from cement kilns. Under Regional Haze, states must consider cost of compliance when evaluating potential controls and the Division believes it is inappropriate to recommend essentially unproven technologies beyond LAER under Regional Haze.

The only existing US cement kiln with an operating SCR for NO_x control, the Lafarge Joppa Kiln 1, has very little publicly available information, including costs. Based on the information available to the Division, this SCR is achieving 80% control efficiency, which is higher than the 53% control efficiency of the GCC Pueblo SNCR, but without additional cement kilns using SCR for NO_x control it is unclear whether the technology could consistently achieve 80% control efficiency at other facilities, such as GCC Pueblo. Although the Joppa Kiln 1 SCR must maintain an ammonia slip limit, it is not subject a condensable PM limit, which may allow for higher ammonia injection rates to achieve greater NO_x reductions. SNCR technology has also been chosen over SCR under recent consent decrees, BACT, and LAER determinations. Given the limited potential NO_x reductions, unknown cost, and lack of SCR installations on comparable preheater/precalciner kilns, the Division still considers SCR technology infeasible for cement kilns and it will not be analyzed further.

Staged and Controlled Combustion (SCC): EPA's ACT NO_x Emissions from New Cement Kilns also discusses staged and controlled combustion control (SCC) for cement kilns. The document explains SCC as follows:

> *SCC works by staging the introduction of fuel, combustion air, and feed material in a manner to minimize NOx formation and reduce NOx to nitrogen. NOx formed in the kiln's combustion zone is chemically reduced by maintaining a reducing atmosphere at the kiln feed end by firing fuel in this region. The reducing atmosphere is maintained in the calciner region by controlling combustion air such that the calcining fuel is first burned under reducing conditions to reduce NOx and then burned under oxidizing conditions to complete the combustion reaction. Controlling the introduction of raw meal allows for control of the calciner temperature. Through these mechanisms, both fuel NOx and thermal NOx are controlled. The combustion chamber allows for improved control over the introduction of tertiary air in the calciner region, which helps to promote the proper reducing environment for NOx control.*

SCC generally involves the staging of both air and fuel. Indirect firing is required for air staging, and LNB achieve one form of staged combustion. Both are employed at the GCC Pueblo kiln. The version of SCC discussed here combines indirect firing with LNB in the kiln with a combustion of a large portion of the fuel in a preheater/precalciner with a tertiary duct to return air from the clinker cooler to the preheater/precalciner. The Division has not identified additional upgrades to the staged combustion that would achieve additional NO_x reductions.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology
Table 7 summarizes each available technology and technical feasibility for NO_x control on the GCC Pueblo kiln.

Table 7: GCC Pueblo Kiln - NO_x Technology Options and Technical Feasibility

Technology	Emission Control Efficiency (%)	Technically Feasible? (Y = yes, N = no)
Baseline - LNB + SNCR + SCC (53% Control)	N/A	Y - installed
Fuel Substitution - Firing TDF	20 - 30%	Y - in use when available
SCR	N/A	N

The Division did not identify any additional controls that can achieve additional NOx reductions.

Emission Limit Tightening: Although the Division did not identify any additional NO_x control measures, it also evaluated tightening emission limits for the GCC Pueblo kiln. GCC currently has a 12-month rolling average emission NO_x limit of 2.32 lb/ton of clinker. The CEMEX Lyons and Holcim Florence kilns are subject to 30-day Rolling Average NO_x limits, and the Division considers this shorter averaging period helps reduce emission variability, in line with the goals of the Regional Haze program. As discussed earlier, the Division has determined that setting a higher SNCR uptime requirement would likely increase in ammonia and condensable PM emissions over the city of Pueblo, which is not a reasonable trade-off for the potential NO_x reductions. Therefore, the 30-day emission limit should be based on 2016-2018 baseline emissions under the currently permitted "as-needed" SNCR operating requirement. As shown in Table 5, the 30-day rolling averages for the GCC Pueblo kiln range from 1.61 - 2.70 lb/ton of clinker. This range is much larger than the 12-month rolling averages which range from 1.82 - 2.11 lb/ton of clinker. To account for the emission variability from cement kilns, the Division set RP limits for the Holcim Florence cement kiln based on the 99th percentile of the 30-day rolling averages, during the first Regional Haze planning period. Using this same metric would result in a NO_x limit of 2.65 lb/ton of clinker for the GCC Pueblo kiln. This emission rate is less than 2% lower than the maximum 30-day rolling average of 2.70 lb/ton of clinker. The Division believes this slightly lower emission limit would not provide meaningful emission reductions. Therefore, the Division considers a 30-day rolling average limit of 2.70 lb/ton of clinker to be appropriate. Although this emission rate is higher than the current annual limit of 2.32 lb/ton of clinker, the Division believes this higher emission rate allows the facility to properly maintain the in-line raw mill which can help avoid large increase in condensable PM emissions. Additionally, without additional control options or a consistent supply of TDF, GCC would likely need to increase ammonia injection rates to achieve greater NO_x reductions. As discussed in the SNCR analysis above, higher ammonia injection rates can provide higher NOx control efficiency, but the side effect is that the increased ammonia slip can result in a detached plume of sulfate, chloride, or nitrate particulates that impair visibility. Thus, the Division recommends a 30-day NO_x limit of 2.70 lb/ton and retaining the annual limit of 1,100 TPY. The facility has recently completed upgrades to increase clinker production and as the facility reaches maximum clinker production, the kiln will need to decrease its 12-month rolling average NO_x emissions from 1.97 lb/ton of clinker to approximately 1.87 lb/ton of clinker to remain within the 1,100 TPY limit. The Division will continue working with GCC to identify opportunities to reduce NO_x emissions without leading to significant increases in other pollutants.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

There are no associated costs of compliance since no options other than continuing proper operation of the kiln and the existing LNB + SNCR units are considered technically feasible and cost effective.

Factor 2: Time Necessary for Compliance

There is no additional time required for compliance since no options other than continuing proper operation of the kiln and the existing LNB + SNCR units are considered technically feasible and cost effective.

Factor 3: Energy and Non-Air Quality Impacts

There are no additional energy and non-air quality impacts associated with the continued proper operation of the kiln and LNB+SNCR units on the GCC Pueblo kiln.

Factor 4: Remaining Useful Life

GCC has not announced a closure date for the Pueblo kiln or its associated limestone quarry. Therefore, the Division assumes that the kiln will remain in operation for at least 20 years.

Because no additional control options are considered technically feasible and cost effective, remaining useful life does not impact cost estimates for additional controls.

Determinations

Upgrades to the existing NO_x control system were evaluated, and the state has determined that meaningful upgrades to the system are not available. Because the kiln will remain in operation for 20 years or more, the Division also evaluated emission limit tightening. The kiln is currently subject to a 12-month rolling average lb/ton of clinker limit, whereas the CEMEX Lyons kiln and Holcim Florence kiln are subject to 30-day rolling average limits. The Division has determined that the existing 12-month rolling average limits are set an appropriate level, and a new 30-day rolling average limit is appropriate to reduce short-term emission variability. This new 30-day rolling average will ensure the facility continues operating the SNCR as much as practicable while allowing the facility to properly maintain the in-line raw mill, which limits excess ammonia emissions that could lead to excessive condensable PM emissions or visible plumes. These emission limits avoid trading a slight NO_x decrease for an increase in other pollutants.

Based upon its consideration of the four factors summarized herein and detailed in Appendix C, the Division recommends that NO_x RP is complying with the following emission rate and annual limits:

1) The following NO_x emission limits shall remain in effect for this planning period:

Kiln: 2.70 lb/ton of clinker (30-day rolling average)
2.32 lb/ton of clinker (12-month rolling average)
1,100.0 TPY (12-month rolling average)

The state assumes that the RP emission limits can be achieved through continued proper operation and maintenance of the kiln, including the LNB and SNCR controls. The Division has determined that these emission limits are achievable without additional capital investment through the four-factor analysis.

Appendix C

Tri-Mer Brochure

Tri-Mer® CORPORATION

Technology Leader
multi-pollutant control

World's Largest Supplier of Ceramic Catalyst Filter Systems

Boiler MACT • CISWI MACT • Cement NESHAP

All-in-One Solution

Tri-Mer Ceramic Catalyst Filter Systems are state-of-the art for removing particulate (PM), SO2, HCl, mercury and heavy metals. Simultaneously, the ceramic catalyst filters destroy NOx, cement organic HAPs, and dioxins. Systems can be configured for any combination of the pollutants.

The system is completely dry, with no water consumption. Disposal of the dry collected waste is straightforward. Large gas flow volumes can be accommodated.

Particulate Control

Tri-Mer Ceramic Catalyst Filters are excellent at removing all sizes of particulate from gas sources above 300˚F, including PM10, PM2.5, and submicron. Typical outlet levels are less than 0.001 grains/dscf (2.0 mg/Nm^3) regardless of inlet loading.

NOx Control

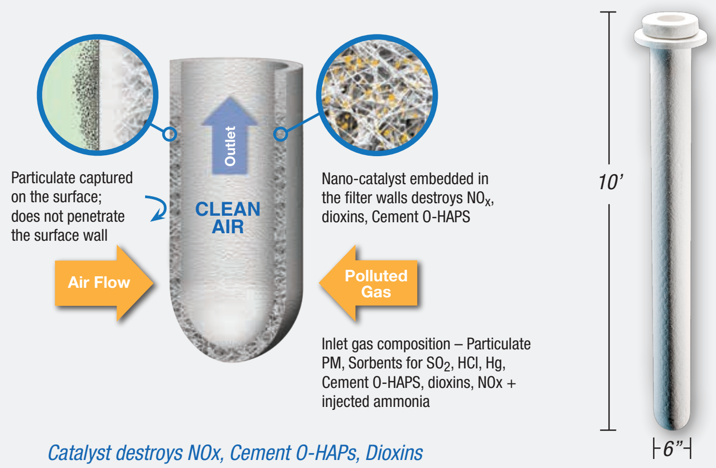
Catalytic filter tubes have nanobits of SCR catalyst embedded in the filter walls. Operating range is 350˚F to 950˚F. The exceptionally large reactive surface area of the micronized catalyst produces high NOx removal at temperatures notably lower than standard SCR. Good results start at 350˚F and improve to 95% removal at 450˚F and above (standard "big block" SCR requires 650˚F or higher for similar efficiency).

The unique structure of the filters captures process particulate on its outer surface, thus keeping it away from the nano-catalyst inside the filter walls. This prevents PM blinding and poisoning of the catalyst and greatly extends the catalyst life compared to standard SCR..

Cement O-HAPs and THC Control

Cement organic HAPS are also destroyed by the embedded catalyst. Good removal on the primary Cement O-HAPs occurs at temperatures over 400˚F, with excellent results on all Cement O-HAPS approaching 500˚F. Dioxins are also destroyed by the filters, typically with 95% efficiency or better at temperatures up to 500˚F.

Cut-away of Filter Tube with Embedded Nano-catalysts



Catalyst destroys NOx, Cement O-HAPs, Dioxins

SO2, HCl, Acid Gases, & Mercury Control

For dry scrubbing of acid gases, Tri-Mer filter systems use injection of hydrated lime or SBC upstream of the filters. Removal of SO2 is typically above 90% and HCl better than 97%. The approach for mercury depends on the Hg species in the gas. Activated carbon and other sorbents, some blended with the acid gas sorbents, are selected on a case-by-case basis.

www.tri-mer.com

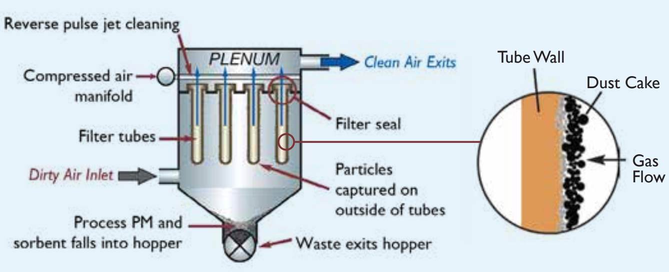
Boilers, Cement, Glass, Incinerators, Stationary Diesel

CERAMIC CATALYST Filter Systems

Controls PM, S02, HCl, Hg, NOx, Dioxins, Cement O-HAPs

Operation and Maintenance

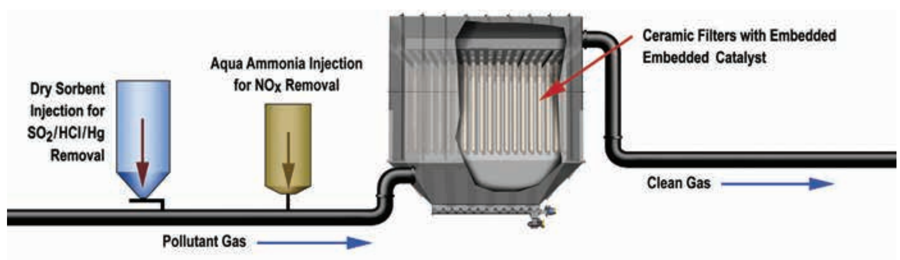
Tri-Mer's Ceramic Catalyst Filter System uses a baghouse configuration with a reverse pulse-jet cleaning action. The filters are back-flushed with air or inert gas. The design has been engineered for easy filter installation and maintenance. Filter tubes are manufactured in various sizes, the largest of which is 10' long and 6" in diameter, including an integral mounting flange. Filter life averages 5 to 10 years on most applications.



Reverse pulse-jet cleaning mechanism for the filter tubes.
Filter tube wall is 3/4" thick with catalyst embedded inside.

Initial system cost is lower than competing options, with much better performance and flexibility. Pressure drop is 4" w.g. – lower than the total energy usage of multi-step systems.

Modular systems to treat any flow volume



Controls PM, S02, HCl, Hg, NOx, Dioxins, Cement O-HAPs

Tri-Mer's Ceramic Catalyst Filter System is the Low Cost Solution

Tri-Mer Corporation, a technology leader in air pollution control, provides turnkey engineering, manufacturing, installation, and service of its ceramic catalytic catalyst filter systems.

Tri-Mer Corporation
Factory and Headquarters
1400 Monroe St., Owosso, MI 48867

Primary Applications

- Boiler MACT compliance for coal, biomass, wood
- Cement NESHAP Organic HAPs
- Glass furnaces
- CISWI Incinerator MACT
- Stationary diesel for ships at dock
- Metal smelting, mineral processing
- Chemical production

More Applications

Air Pollution Control

- Medical waste
- Soil cleaning
- Foundry processes
- Energy production
- Fire testing
- Many specialized high temp applications

Product Collection/Recovery

- Titanium dioxide production
- Fumed silica production
- Catalyst manufacturing
- Platinum smelting
- Metal powder production
- Activated carbon production

Tri-Mer® CORPORATION Technology Leader *multi-pollutant control*

www.tri-mer.com

Appendix D

GEA Brochure

Hot gas filtration with ceramic candles

A multifunctional filter for the simultaneous removal of particulate, acid gases and NOx from flue gases

engineering for
a better world

gea.com

Discover the benefits of ceramic candle filters

GEA high temperature filters with ceramic elements remove particulates and are now available as BisCat ceramic filters with an embedded catalyst matrix allowing removal of NOx, dioxins, mercury and VOC. The filter elements are chemically inert and corrosion-resistant.

Emission control advantages

Ceramic filter elements show very low dust emissions < 2 mg/Nm³ and are thermally stable up to high operating temperatures. No cooling of flue gases is required and no thermal heat energy is wasted.

Filter elements are cleaned online during operation by means of separate, compressed air jet pulses. The filter elements are placed in a single or multi-compartment housing to handle large volumetric flow rates. This construction technique allows for maintenance of a single module while others continue to operate, without interruption of the process itself.

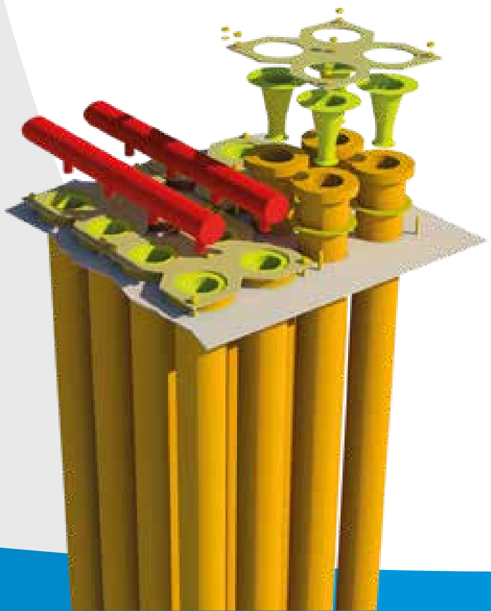
The injection of lime-based reagents allows for control of inorganic gaseous emissions like HF, HCl, SOx. The rigid candle structure enables surface filtration and forms a first layer of reactive dust for absorption processes.

BisCat ceramic catalyst filters

In addition to treating particulate and acid gases, the BisCat ceramic catalyst filters is enriched with a catalyst providing effective NOx removal by using upfront ammonia injection and replace a conventional selective catalyst reactor (SCR).

The BisCat filter solution is combining three process steps in one unit for advanced emission control:

- Dedusting
- Removal of acid components
- Reducing THC and NOx



Details of BisCat installation

CERAMIC FILTERS	BISCAT
• Low dust emissions • High operating temperatures • Excellent gas permeability • Lightweight construction • Long service lifetime	• Effective NOx removal • Low differential pressure • Single emission control unit • Multi-pollutant performance

APPLICATIONS

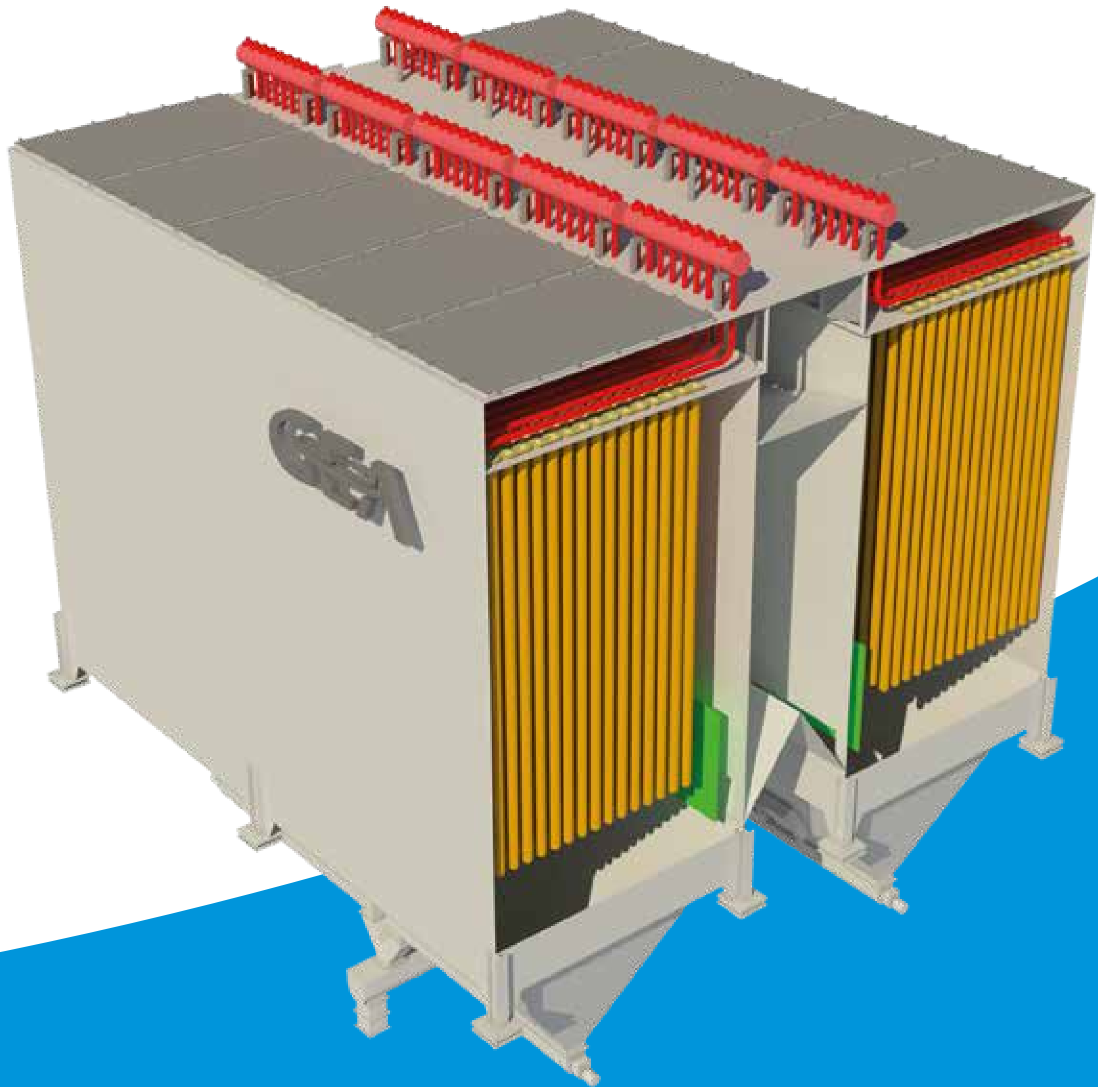
- Glass furnaces
- Cement kilns and coolers
- Incinerators
- Refineries
- Roasters

Special features of ceramic candle filters with pulse jet technology

- Low differential pressure
- Dust monitoring system (Broken Bag Detector) allows for safe operation with almost zero dust emission
- Low a/c ratio allows n-1 operation for longer periods
- Baffle plates protect candles from direct gas flow intake in raw gas compartment
- Clean gas dampers are designed for low differential pressure
- Candle installation period is short, due to easy and fast candle piece assembly
- Penthouse equipped with lifting devices to handle candles and clean gas compartment covers

The special GEA design allows for candle length of up to six meters. A downholder plate holds four candles in place to a common tubesheet. The intake nozzle protects candles from excessive abrasion by means of compressed air and the sealing between candle and head plate prevents from bypass gas.

Standard reverse pulse jet methods, commonly used in fabric filter baghouses, are used for ceramic filter cleaning. A pulse of compressed air is sent down in the center of the filter elements and cleans the accumulated dust from the outer surface of the tubes. The particulate falls into a lower hopper and is removed through an airlock device. Filters are cleaned on-line, with no need to isolate individual housings or sections.



BisCat system

engineering for
a better world

We live our values.

Excellence • Passion • Integrity • Responsibility • GEA-versity

GEA is a global technology company with multi-billion euro sales operations in more than 50 countries. Founded in 1881 the company is one of the largest providers of innovative equipment and process technology. GEA is listed in the STOXX® Europe 600 Index. In addition, the company is included in selected MSCI Global Sustainability Indexes.

GEA Germany
GEA Bischoff GmbH
Ruhrallee 311
45136 Essen, Germany

Tel +49 201 8948 0

gea.com/contact
gea.com

Appendix E

Haldor Topsoe Brochure

TopFrax™ catalytic filters

Remove gas emissions and dust in one single process

Breakthrough catalytic filters trap dust,
while removing NOx, dioxins, CO and VOCs

www.topsoe.com

HALDOR TOPSØE

Are regulators putting the **squeeze** on your business?

Topsoe's new TopFrax™ catalytic filter makes compliance a whole lot more affordable

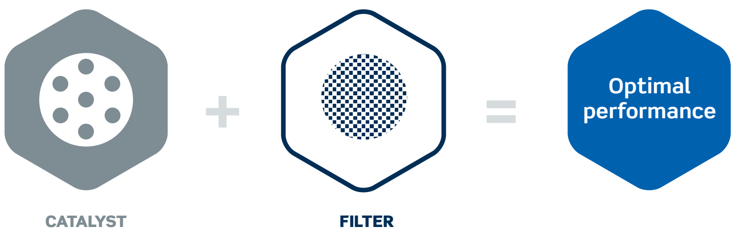
Authorities in many countries are tightening emissions standards by reducing particle permissible levels and adding new gases to the list of regulated components. Compliance is costly, requiring substantial investments in new abatement technologies.

At Topsoe, we hear producers calling not just for new technologies, but for innovation that makes compliance affordable. That's what our TopFrax™ catalytic filter is all about.

Trap dust and remove pollutants
TopFrax™ are patent-pending catalyst-coated filters designed to treat off-gases in high-dust environments found in a wide range of industries and activities, including:

- Glass production
- Cement production
- Waste incineration
- Bio-mass boilers
- Steel production

Built on decades of leadership in filtration and catalysis, these breakthrough solutions can transform the economics of meeting regulatory emissions.



The fact that we both master catalysts and process technology gives us the "big picture" view it takes to ensure optimal performance

Remove gas emissions and dust **in one single process**

Upgrading is easy and affordable, if you use a candle system

Topsoe's catalytic filter is designed to give any facility the option of treating off-gases along with trapping dust. TopFrax™ is a catalytic ceramic candle solution that provides high removal performance efficiency at both high and low operating temperatures and with the resistance of sparks contained in off-gases.

TopFrax™ catalytic filter candle
The TopFrax™ catalytic filter candle consists of a high-temperature-resistant ceramic filter impregnated with carefully selected catalytic compounds. Benefits include:

- Simultaneous dust and multiple gaseous compounds removal in a single step
- No need for costly, space-demanding tail-end gas removal equipment
- Reinforced at flanges and bottom to enhance mechanical durability
- Catalytic ceramic filter accommodates temperatures as high as 400°C (752°F)
- No contact between catalyst and potentially harmful particles
- Exceptional resistance to catalyst poisoning
- Effective down to 180°C (356°F) operation
- Easy to install and handle

TopFrax™ ceramic catalytic filter

A broad spectrum of **regulated pollutants**

While the filters trap dust, the catalyst removes NOx, dioxins, CO and VOC

Dust
TopFrax™ effectively blocks particulates and dust particles at the filter surface the same way conventional filters do, ensuring full compliance with stringent emission standards.

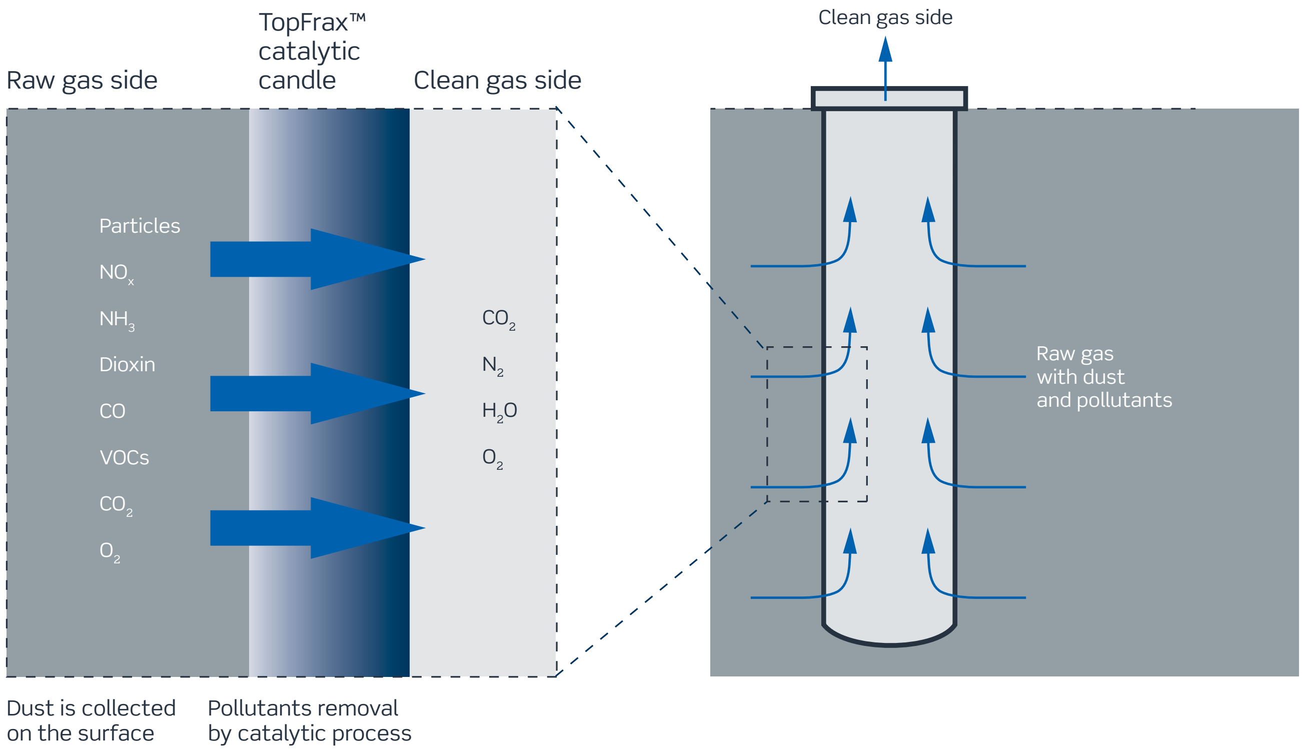
TopFrax™ candles are made from either refractory ceramics or fibers with low bio-persistance. Both products trap dust emissions (below $PM_{2.5}$) down to 1 mg/Nm³.

NOx
TopFrax™ uses selective catalytic reduction (SCR) to remove NOx from off-gases, by utilizing ammonia to convert to harmless nitrogen and water

Dioxins
TopFrax™ also ensures compliance with limits on dioxins and furans, by treating more than 99% of these by converting them into harmless compounds and reducing their concentrations to below 0.1 ng/Nm³, TEQ.

CO and VOCs
The catalytic sites on TopFrax™ candles also oxidize CO and volatile organic compounds into harmless CO_2 and H_2O.

The TopFrax™ oxidation version ensures optimal combustion of VOCs with no additional emission of CO.



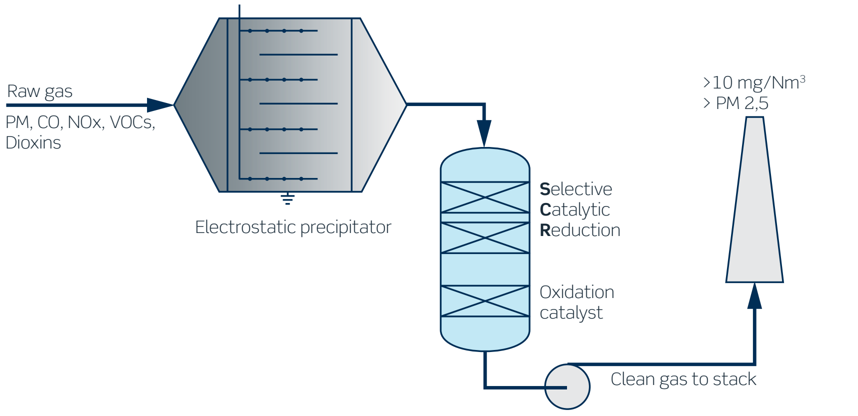
Cut technology costs

The Topsoe catalytic filter solution TopFrax™ can help you reduce capital expenditures compared to competing solutions relying on separate DeNOx and oxidation technologies

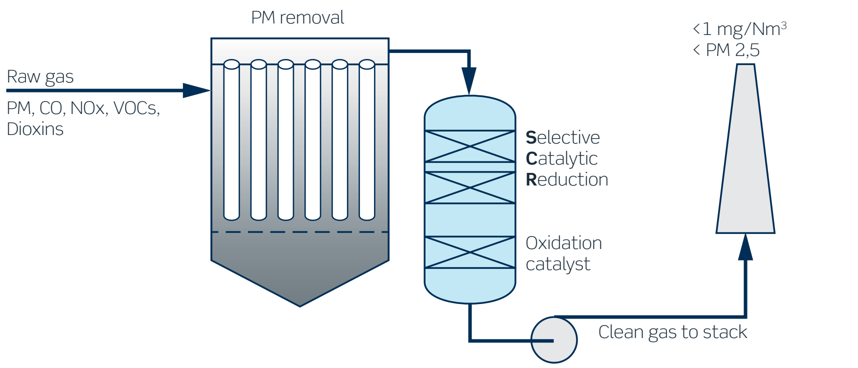
Filtration unit and tail end removal of NOx and VOC

Traditional solution based on separated technologies

Non-catalytic filters



Non-catalytic filters

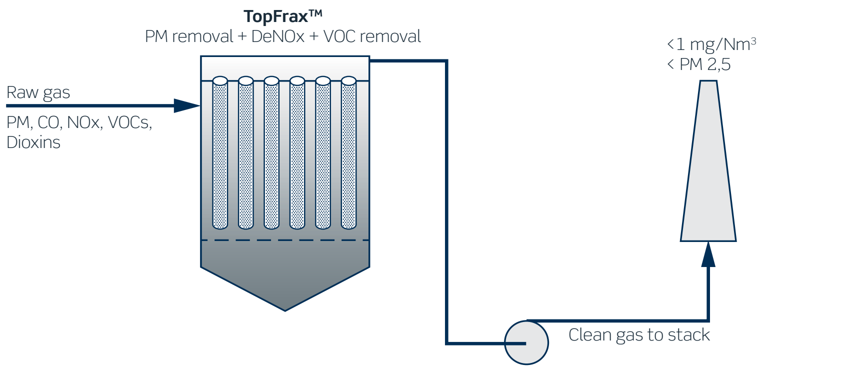


Catalytic filtration - integrated solution

Catalytic filter solution:

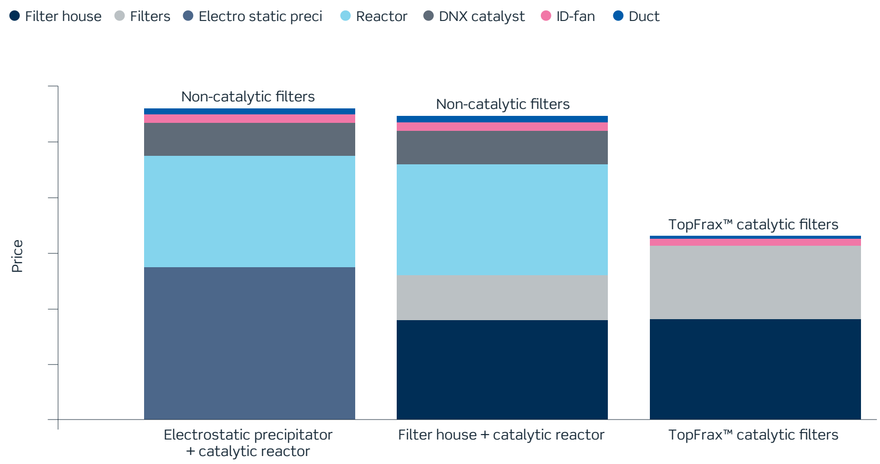
- Lower CAPEX
- Less foot print
- Lower pressure drop
- Less maintenance
- Lower cost of ownership

TopFrax™ catalytic filters



Comparison of lump sum investment

CAPEX savings from installing catalytic filters.



Related technologies

Discover the full range of Topsoe catalysts and technologies for optimizing performance

Optimized performance often means ensuring that multiple technologies and components are tuned to each other. If you're not already using them, please consider these related offerings from Topsoe.

VOC

VOC removal
Regulatory pressure on VOC emissions has never been greater, and we can help you meet the challenge by removing VOCs from off-gases via low-temperature catalytic processes. Our solutions deliver reduction efficiencies exceeding 99%, without creating any secondary pollutants. Our catalysts remove VOCs from air and waste gas streams in an energy-efficient and environmentally friendly manner.

S

Sulfur removal
As emission regulations continue to get tighter around the world, optimal handling of sulfurous gases is becoming increasingly important. In addition to meeting regulatory requirements, we make sure our solutions also make financial sense. Due to their high availability, energy efficiency and flexibility, our sulfur removal systems deliver market-leading performance. They can even be used to convert otherwise costly waste into valuable commercial-grade sulfuric acid.

Why partner with **Haldor Topsoe**

The Topsoe advantage lies not just in individual solutions, but in how our solutions work together

When you partner with Haldor Topsoe, you partner not only with the world's experts in catalysis, surface science and emissions management. You also partner with a company that takes a uniquely holistic approach to your plant and your business.

When we look at your plant, we look at the big picture – and then apply the full breadth of our expertise to deliver a thoroughly tailored solution, where individual components work together to ensure environmental compliance at the lowest possible cost.

Haldor Topsoe is a world leader in catalysis and surface science, committed to helping our customers achieve optimal performance. We enable companies to get the most out of their processes and products, using the least possible energy and resources, in the most responsible way. We are headquartered in Denmark and do project development, R&D, engineering, production, and sales & service across the globe.

Get in touch today
www.topsoe.com/topfrax

Haldor Topsoe A/S, cvr 41853816 | CCM | 0224.2017/Rev.1

HALDOR TOPSØE

CataFlex™ catalytic filter bags

Remove pollutants and **trap** dust in one **single** step

Breakthrough catalytic filter bags trap dust, while removing dioxins, NOx and NH_3

www.topsoe.com

HALDOR TOPSØE

Are regulators putting the **squeeze** on your business?

Topsoe's CataFlex™ catalytic filter bags make compliance a whole lot more affordable

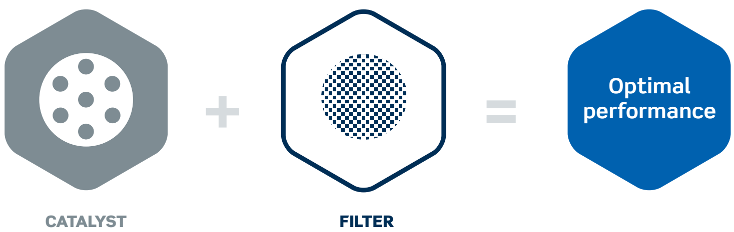
Authorities in many countries are tightening emissions standards by reducing permissible levels and adding new gases and particles to the list of regulated components. Compliance is costly, requiring substantial investments in new abatement technologies.

At Topsoe, we hear producers calling not just for new technologies, but for innovation that makes compliance affordable. That's what our CataFlex™ catalytic filter bags are all about.

Trap dust and remove pollutants
CataFlex™ are catalyst-coated filter bags designed to treat off-gases in high-dust environments found in a wide range of industries and activities, including:

- Waste incineration
- Biomass boilers
- Power plants
- Cement production
- Glass production
- Steel production

Built on decades of leadership in filtration and catalysis, these breakthrough solutions can transform the economics of meeting regulatory emissions.



The fact that we both master catalysts and process technology gives us the "big picture" view it takes to ensure optimal performance

Single step **removal** of dioxins, NOx and NH_3

Upgrading is easy and affordable

Topsoe's catalytic filter systems are designed to give any facility the option of treating off-gases along with trapping dust. CataFlex™ is the ideal choice for facilities already using a filter bag solution.

Designed for use in most industries that require flue gas cleaning, the CataFlex™ catalytic filter bag consists of a catalytic fabric layer installed inside a standard filter bag. Both the catalyst formula and the fabric material for the catalytic inner layer and the dust filtration layer are optimized according to the process requirements.

Benefits include:

- Removes dust and multiple gaseous compounds in a single step
- No need for costly, space-demanding tail-end SCR equipment
- Low pressure drop means no need for costly new ID fans or compressed air
- Accommodates operating temperatures up to 260°C (500°F)
- Bags can be inserted into existing filter houses for an affordable drop-in upgrade
- Life time and pressure drop is comparable to conventional fabric filters
- No contact between catalyst and potentially harmful particles
- Exceptional resistance to catalyst poisoning
- Length up to 10 m (32 ft)
- Longer outer bag lifetime

CataFlex™ catalytic filter bag

A broad spectrum of **regulated pollutants**

While the filters trap dust, the catalyst removes dioxins, NOx and NH_3

SEM image of CataFlex™

Outer layer

Dust
CataFlex™ effectively block particulates and dust particles on the outer layer which consist of a traditional dust filter bag, ensuring full compliance with the stringent emission standards.

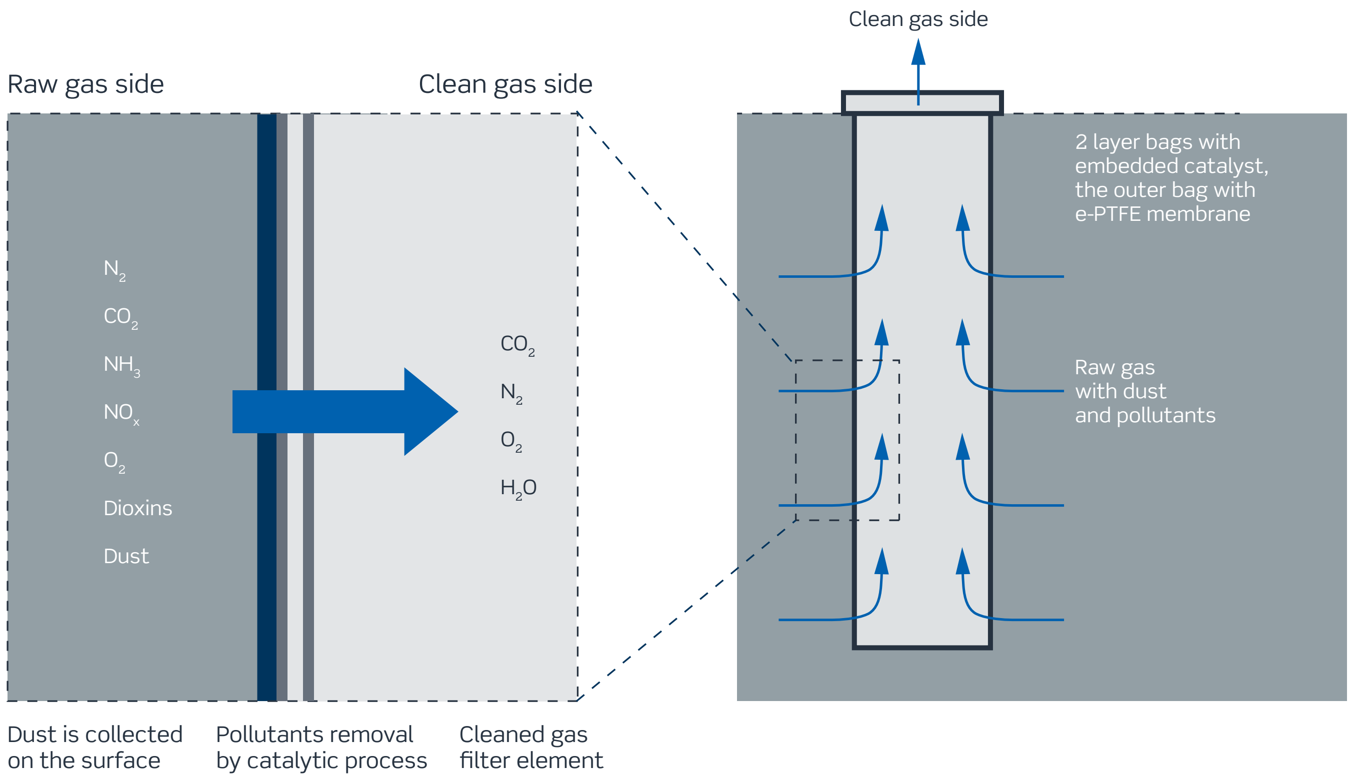
The outer layer of a CataFlex™ filter bag is a conventional filter bag which can be made by different fabrics and with and without PTFE membrane. CataFlex™ reduces dust emissions to below 1 mg/Nm³.

Inner layer

Dioxins destruction
CataFlex™ ensure compliance with limits on dioxins and furans - destruction more than 99% of these by converting them into harmless compounds and reducing their concentrations to below 0.1 ng-TEQ/Nm³.

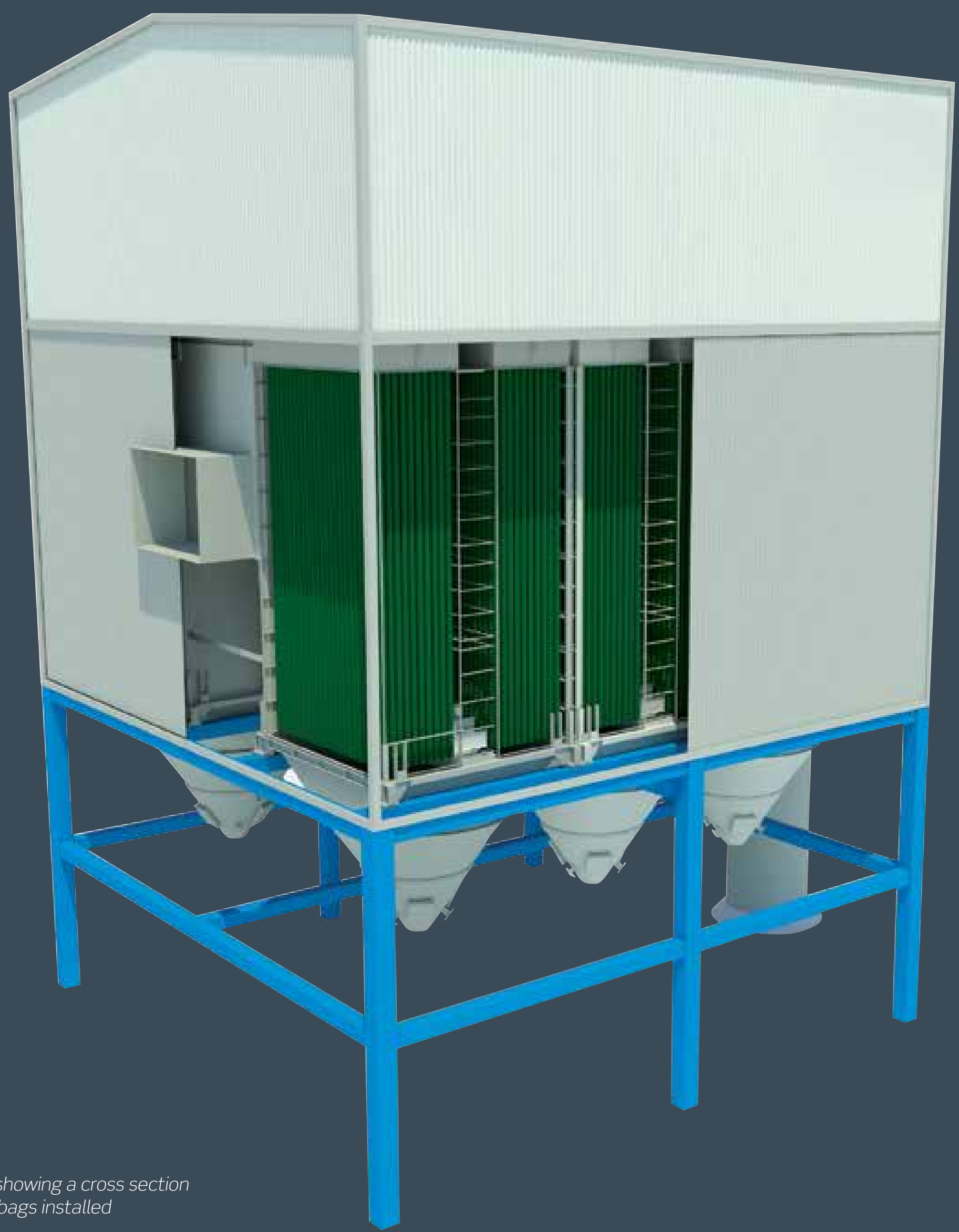
NOx
CataFlex™ use selective catalytic reduction (SCR) to remove NOx from off-gas, either by utilizing ammonia contained in the off-gas or via ammonia injection. The NOx is converted to harmless nitrogen and water.

NH_3
CataFlex™ eliminates any NH_3 slip from upstream selective non-catalytic reduction (SNCR) of NOx. This complies with NH_3 regulations and makes SNCR control easier.



Cut equipment **costs**

The Topsoe catalytic filter bag solution can help you reduce capital expenditures by up to 80% compared to competing solutions relying on separate dust removal and SCR technology.

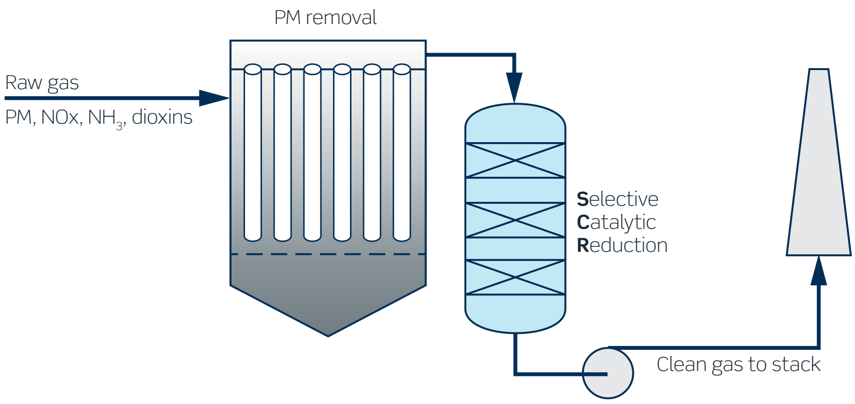


Typical fabric filter showing a cross section with catalytic filter bags installed

Filtration unit and tail end removal of NOx and NH_3

Traditional solution based on separated technologies

Non-catalytic filters

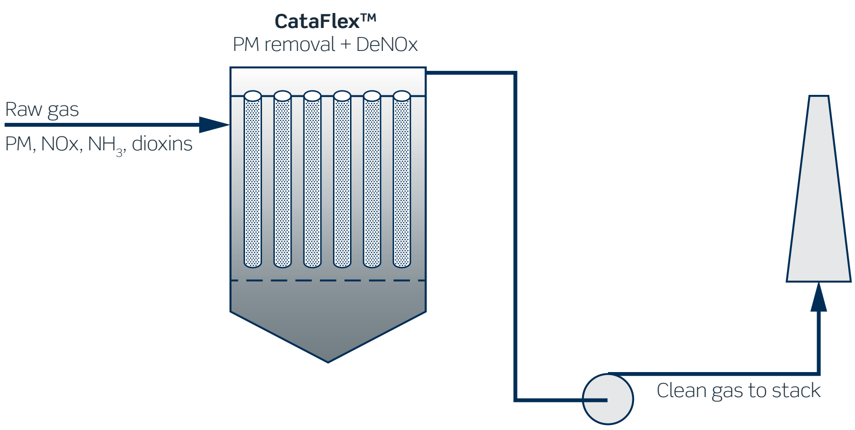


Catalytic filtration - integrated solution

Catalytic filter bag solution:

- Lower cost of ownership
- Less foot print
- Lower pressure drop
- Less maintenance

Catalytic filters



Related technologies

Discover the full range of Topsoe catalysts and technologies for optimizing performance

Optimized performance often means ensuring that multiple technologies and components are tuned to each other. If you're not already using them, please consider these related offerings from Topsoe.

S

Sulfur removal
As emission regulations continue to get tighter around the world, optimal handling of sulfurous gases is becoming increasingly important. In addition to meeting regulatory requirements, we make sure our solutions also make financial sense. Due to their high availability, energy efficiency and flexibility, our sulfur removal systems deliver market-leading performance. They can even be used to convert otherwise costly waste into valuable commercial-grade sulfuric acid.

VOC

VOC removal
Regulatory pressure on VOC emissions has never been greater, and we can help you meet the challenge by removing VOCs from off-gases via low-temperature catalytic processes. Our solutions deliver reduction efficiencies exceeding 99%, without creating any secondary pollutants. Our catalysts remove VOCs from air and waste gas streams in an energy-efficient and environmentally friendly manner.

Why partner with **Haldor Topsoe**

The Topsoe advantage lies not just in individual solutions, but in how our solutions work together

When you partner with Haldor Topsoe, you partner not only with the world's experts in catalysis, surface science and emissions management. You also partner with a company that takes a uniquely holistic approach to your plant and your business.

When we look at your plant, we look at the big picture – and then apply the full breadth of our expertise to deliver a thoroughly tailored solution, where individual components work together to maximize your plant's performance and your business success.

Haldor Topsoe is a world leader in catalysis and surface science. We are committed to helping our customers achieve optimal performance. We enable our customers to get the most out of their processes and products, using the least possible energy and resources, in the most responsible way. This focus on our customers' performance, backed by our reputation for reliability, makes sure we add the most value to our customers and the world.

Get in touch today
www.topsoe.com/Cataflex

Haldor Topsoe A/S, cvr 41853816 | GMC | 0268.2019/Rev.1

HALDOR TOPSØE

Appendix F

Tri-Mer Proposal

TECHNICAL FEASIBILITY ASSESSMENT

APPLICABILITY OF CERAMIC FILTERS FOR CEMENT PLANT POLLUTION CONTROL

REFERENCE NUMBER: **P-22.518**
REVISION: 0

PREPARED FOR WINGRA ENGINEERING

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DOCUMENT ISSUED:
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INTRODUCTION

In response to your recent request, we are pleased to provide Wingra Engineering with our initial assessment relating to the applicability of Ceramic Filter Technology at both the Holcim, Florence Site in Colorado, and the GCC, Pueblo Site in Colorado for multi-pollutant control.

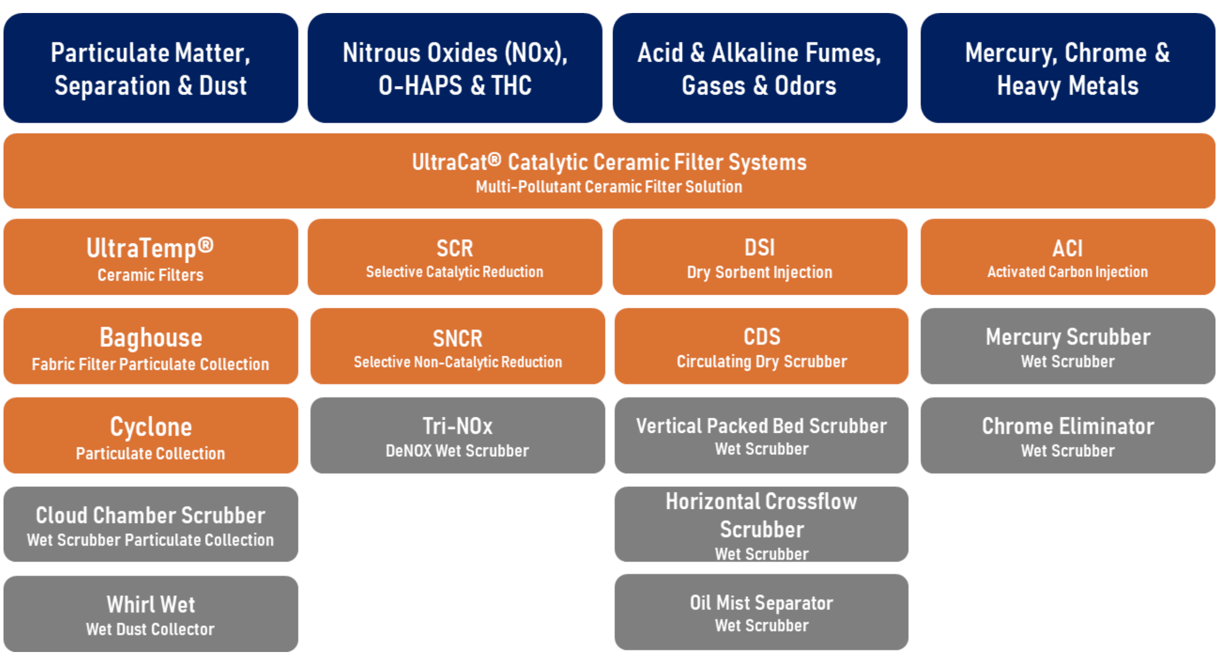
Ceramic Filter Technology has been utilized as a premier solution for Air Pollution Control (APC) for a number of decades, with Tri-Mer having installed over 75% of the ceramic filter systems operating across North America today. The technology has been enhanced considerably since the first US installation in the 2000's, with significant advancements in both the filter technology, and the overall multi-pollutant solution installed.

Across North America, while the technology has predominately been installed in the glass industry, it has wide applicability to a wide range of other industries. Specifically in respect to the cement industry, ceramic filter technology has been installed for the purposes of multi-pollutant reduction into a number of cement plants both in Europe and Asia, while there is also a major cement installation in the US.

Based on the initial information received, we expect that Tri-Mer's ceramic filter technology can be installed to both sites to fully achieve the requirements set forth in respect to both taking on the inlet conditions and operational requirements of both sites, while also meeting the legislative requirements for PM, NOx and SOx removal. Importantly, following our initial assessment, we fully expect Tri-Mer's proprietary ceramic filter technology – UltraCat® Catalytic Ceramic Filter Solution (UCF) - can be a cost-effective solution available to these plants.

OUR TECHNOLOGIES

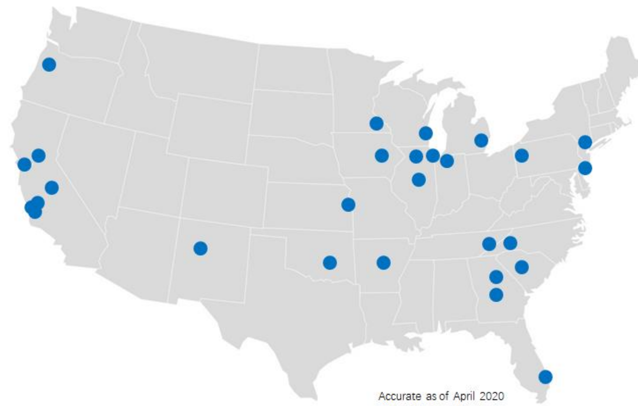
For over 60 years, TMC has developed an enviable reputation in the field of air pollution control. The business performed over 6,000 global installations, providing a wide range of technologies and solutions, to clients across most major industries. TMC has developed a large number of technologies in-house, and works with proven partners to allow for expanded scope where required.



Based in Owosso, Michigan, TMC is a full solution integrator, providing solutions that support our clients reduce almost all major air pollutants. The company headquarters include over 200,000 sq. ft. of state-of-the-art steel fabrication and manufacturing facilities. While our wide range of technologies and solutions provide the strong foundation for the business, it is our dedication to exceed your needs through full and flexible lifecycle services, that help to set us apart.

OUR EXPERIENCE

TMC is the global leader in designing and delivering high-efficiency ceramic filter technology. Through our proprietary UltraCat® Ceramic Filter systems, we have installed over 50,000 ceramic filters across over 40 installations in North America alone. The technology is proven to operate on all pre- and post-combustion processes, mitigating pollutants such as PM, SO_2, SO_3, HCl, O-HAPS, VOC, HF, and NO_x to higher removal rates than industry standard within a single system, while heavy metals, mercury, dioxins, and VOC O-HAPS can also be removed.



DESIGN PARAMETERS

To provide a basis to this assessment, our proposed solution has been evaluated based on the design and process details as outlined below:

Facility		Holcim Florence Portland Cement Plant Florence, Colorado Preheater/Precalciner Kiln	GCC Pueblo Pueblo Cement Plant Pueblo, Colorado Preheater/Precalciner Kiln
AIRS Point		111	039
Fuels		Coal, NG, TDF, Pet Coke	Coal, NG, TDF
Capacity	tons per day	5,950	3,750
Current Control for PM		Baghouse	Baghouse
Current Control for SO_2		Inherent & Wet Scrubbing	Inherent Scrubbing
Current Control for NOx		SNCR	SNCR
Exhaust Flow Rate (acfm)	acfm	827,731	306,708
Exhaust Temperature (°F)	°F	166	377
Exhaust Moisture (%)	vol.%	13.9	8.2
PM10 (Filterable)	(lbs/hr)	61,979.2	39,062.5
PM10 (Condensable)	(lbs/hr)	0.0	10,473.7
PM_{10} (Total)	(lbs/hr)	61,979.2	49,536.2
SO_2	(lbs/hr)	164.6	215.4
NOx	(lbs/hr)	1,041.3	656.3

DESIGN ASSUMPTIONS

Without gaining full access to full details regarding the operation and design of the existing systems in place at Holcim, Florence and GCC, Rio Grande, we have made the following assumptions, exclusions and clarifications within our overall assessment. Tri-Mer has the full capability to investigate, design and supply many of these elements within a full turnkey solution:

- Both cement plants use water quench system for adjustment of the flue gas temperature at baghouse inlet
- Adjustments to decreasing quench efficiency can be easily made in order to increase the flue gas temperature to about 550°F for 90% NOx removal efficiency. Tri-Mer is presently investigating capabilities to operate its UCF filters at lower temperature
- Existing baghouse is designed for 12' bag filters.
- Existing baghouse is designed for a face velocity at filter (air-to-cloth ratio) of 0.8 m/min (about 2.7 fpm)
- Typical operation temperature for the existing baghouse is limited to 425°F
- Existing infrastructure for online filter cleaning consists of pulse jet system and can be used for the cleaning of the UCF® filters, e.g. without any modifications to jet tubes, solenoid valves, tank volumes, available pressure and compressed air class 2 quality requirements.
- Existing ID-fans will be capable to handle additional volumetric flow and pressure drop requirements

OUR SOLUTION

With our extensive range of air pollution control technologies, our approach is always to identify the best technical fit for the specific project. As each project, client and site is unique, we ascertain the most appropriate technology and applicability of these technologies. For this assessment, we have evaluated ceramic filter technology only, and looked into the most economical option for the two sites.

Traditionally, ceramic filter technology is installed within its own filter housing (either UCF or UTF), both for brownfield and greenfield projects. More recently, where a baghouse is already installed and its design meets the flow and particulate requirements, we can utilize the existing baghouse and replace the existing filter bags with ceramic filters. This concept has been achieved outside of the US, while Tri-Mer has undertaken extensive design and capability assessments on other cement plants to ensure its applicability. Therefore, for both sites, our proposed Bag-to-Ceramic Filter Retrofit solution would include:

- Structural analysis of the existing baghouse with recommendations for structural improvement
- Engineering package and design of upgraded internals for the replacement of bag- with catalytically activated ceramic filters
- Engineering package with analysis of existing ID-fan capacity and if required, booster fan upgrade recommendations
- Upgrade equipment, both internal replacements and structural modifications
- Catalytically activated UCF replacement filters
- Aqua ammonia storage, dosing and injection system, utilizing a 30,000-gal tank for 7+ days holding capacity at GCC Rio Grande and a 4+ days holding capacity at Holcim Florence
- Mechanical and electrical installation
- Site supervision

EXPECTED SYSTEM PERFORMANCE

Tri-Mer's UltraCat® Catalytic Ceramic Filter Systems are proven to deliver some of the highest levels of pollutant reduction available from commercially proven technology. Based on the initial process information provided, we expect our solution to deliver the following:

Targeted Pollutant	Expected Performance[1]	Test Method
PM10	>99.9%	US EPA Test Method 5
PM2.5	>99.9%	US EPA Test Method 201A or 202
NOx	>90%	US EPA Test Method 7E
SOx	>90%	US EPA Test Method 8A
Ammonia Slip	<10ppm	US EPA Test Method CTM 027

Note: 1 Based on a 30 day rolling average

When considering both NOx and SOx, Tri-Mer have the capability to provide higher levels of performance should it be required through the additional of supplementary technology and solutions.

ESTIMATED COSTS

Utilizing the existing information provided, and aligned with our extensive experience in providing ceramic filter systems, we fully expect that our Bag-to-Ceramic Filter Retrofit would be one of the most cost-effective solutions to providing some of the highest levels of pollutant reduction available

	Holcim, Florence	GCC, Pueblo
Estimated Upfront Capital Investment Cost (US $)	$31,250,800	$8,999,200
Estimated Cost per ton NOx removed per annum[1] *(CapEx + 20 Year OpEx / ton NOx removed per year)*	$1,576/ton of NOx removed per annum	$800/ton of NOx removed per annum
Estimated Lifetime Cost[2] *CapEx + 20 Year OpEx*	USD $129,250,800	USD $41,399,200
Estimated Lifetime Cost per annum[2] *(CapEx + 20 Year OpEx / 20 years)*	USD $6,462,540 per annum	USD $2,069,960 per annum

Note: [1] *the following base cost assumed: Power: US$44/MWh; Aqua ammonia (19 wt.%): US$1,200/ton; Maintenance: US$270,000/yr; Replacement Filters: Once every 10 years.*
[2] *Lifetime cost does not include any assumption to calculate NPV*

The estimated costs shown in the table below are preliminary, and we would require additional information to better ascertain the exact costs for each facility.

ADDED BENEFITS

In addition to the estimated costs, both capital and 20-year lifetime costs, the ceramic filter technology will provide a wide range of benefits to both facilities in comparison to utilizing the existing baghouse (with filter bags) and the installation of a new SCR:

1. **Minimal Footprint**

   Unlike a requirement to add an SCR, our proposed solution to retrofit the existing baghouse, will not require significant footprint to ensure that the site meets increased NOx mitigation. The only footprint that will be required would be for the ammonia storage and transport system to deliver the targeted levels of NOx, SOx and PM,

2. **Reduced Onsite Installation Labor**

   In alignment with the minimal footprint requirement, the proposed retrofit would significantly reduce the requirement for civil, mechanical installation, and electrical installation, reducing both the cost, complexity and the time taken to install the solution.

3. **Minimal Catalyst Plugging**

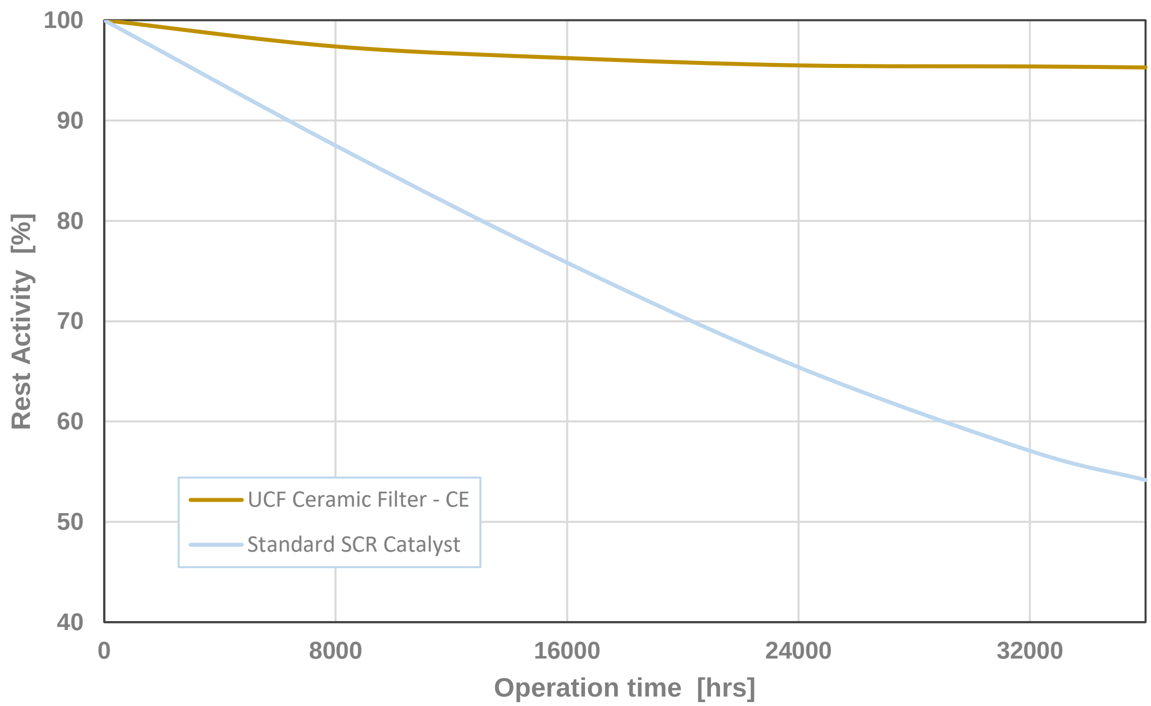
   The SCR DeNOx catalyst is finely distributed throughout the filter wall. Since the ceramic material of the filter is rigid, the filter does not inflate or otherwise change shape or form during jet pulse cleaning, unlike bag filters do. As a consequence, UCF filters always will maintain a residual filter cake as a barrier for any dust constituents, preventing active sites and pore system from being coated and plugged.

4. **Reduced Ammonia Slip**

   Field testing of ammonia slip in service with regenerative glass furnace, e.g. periodical flow reversal, typically show very low ammonia slip well below 10 ppm and even allow the use of ammonia slip monitoring for reliable filter breakage detection.

5. **Negligible Catalyst Deactivation**

   As noted in #3, unlike the catalyst provided within an SCR, the nano-catalyst embedded within the ceramic filter is protected by the ceramic filter and its filter cake. This will ensure that the catalyst is not poisoned and therefore deactivated in the same way as the SCR. Our experience estimates that a SCR catalyst would need to be replaced every 2-3 years, whereas a ceramic filter has no deactivation of the catalyst in a continuous operation for 10 years+.



6. **Temperature Consistency**
   As the existing Baghouse and proposed SCR require different operating temperatures, the installation of an SCR would require significant reheat, driving higher costs and CO2 as a result of this activity. The proposed ceramic filter technology has an optimal operating temperature range at about 550°F.

7. **Continuous Operation**
   Tri-Mer's ceramic filter technology is designed to allow for continuous operation with a capability to provide full redundancy. This will ensure that both cement plants will be able to operate for as long as required, without downtime or bypass associated with the SCR downstream of the Baghouse.

8. **Mitigation of SO_2 to SO_3 Conversion**
   While the UCF filter can excel a 90% NOx conversion at 550°F, SO2 to SO3 conversion at this temperature is expected to be minor.

9. **Experience**
   While the ceramic filter technology may be a relatively new concept to S-based cement plants, ceramic filters are used in a number of cement plants around the world. Tri-Mer work with the leading suppliers of ceramic filters who have the experience and knowledge of cement plant operation. Our knowledge about system design, together with their capabilities in filter technoligy, will ensure that our solution can meet the needs of these projects.

Last Page

Statement of Basis

for Ash Grove Cement Company, Inc.

Original Air Operating Permit was issued May 15, 2004

Significant Modification 1 issued 5/17/07

Administrative Amendment 1 Issued 7/13/07

Administrative Amendment 2 Issued 12/2/10

Administrative Amendment 3 Issued 12/23/13

Administrative Amendment 4 Issued 6/13/18

This document contains the descriptions of the changes and modifications to the Air Operating Permit for Ash Grove Cement Company Inc. These changes and modifications are described in Section below entitled "Modification 1 to Operating Permit."

Purpose of this Statement of Basis

This document summarizes the legal and factual basis for the permit conditions in the Ash Grove Cement Company, Inc. (hereafter referred to as Ash Grove) air operating permit to be issued under the authority of the Washington Clean Air Act, Chapter 70.94 Revised Code of Washington, Chapter 173-401 of the Washington Administrative Code and Puget Sound Clean Air Agency Regulation I, Article 7. Unlike the permit, this document is not legally enforceable. It includes references to the applicable statutory or regulatory provisions that relate to Ash Grove's emissions to the atmosphere. In addition, this statement of basis provides a description of Ash Grove's activities and a compliance history.

Source Description

Ash Grove is a major cement manufacturing plant.

Ash Grove is subject to the requirement to obtain an air operating permit because it is a "major source" as defined in the federal and state operating permit regulations (Title V of the federal Clean Air Act Amendments of 1990 and its implementing regulation 40 CFR Part 70, and RCW 70.94.161 and its implementing regulation, Chapter 173-401 WAC). A major source has the potential to emit more than 100 tons per year of any criteria pollutant (such as CO, SO_2, NOx, VOC, particulate matter, etc.) or 10 tons per year or more of any single hazardous air pollutant listed in Section 112(b) of the federal Clean Air Act (such as hydrochloric acid), or 25 tons per year or more of any combination of hazardous air pollutants.

Ash Grove emits more than 100 tons per year of NOx and SO_2 (see Attachment A, Emission Inventory).

Ash Grove, located in the Duwamish industrial area of Seattle, King County, Washington consists of a single dry kiln with a pre-calcining tower for Portland cement manufacturing. This kiln was installed approved for installation in 1990. It has a capacity to process 92 tons per hour (2200 ton per day and 750,000 ton per year) of type I, II, III clinker while burning coal, natural gas, whole tires, and a small amount of internally generated waste derived fuels approved for use.

This new kiln and associated equipment was constructed on the plant site of the former Lone Star Cement Company constructed before 1970 and at the time of the new plant construction Ash Grove used some of the remaining Lone Star equipment and air pollution control systems.

The air pollution generating and controlling equipment are contained in the Puget Sound Clean Air Agency equipment listing.

KILN

The clinker is manufactured in a long rotary kiln approximately 500 feet long and approximately 15 feet in diameter with nine planetary cooler tubes attached around its lower diameter end. The rotating kiln is a dry process kiln with a slightly inclined angle to allow pre-calcined raw materials from the precalciner tower to be introduced into the upper end of the kiln and move downward toward the lower heated end as the kiln rotates. The burners are located in the slightly lower end of the kiln. Heat from burning various fuels provides the heat to finish the calcining process in the higher temperature end of the kiln. The kiln contains limestone ($CaCO_3$) which decarbonates or calcines (CO_2 is driven off) to lime (CaO). Further heating of the materials traveling down the kiln allows calcium in the lime to fuse with alumina and iron which initiates the inclusion of silica into the chemical process. The reaction with silica is an exothermic reaction initiated by intense heat (>2500°F). The production of the various compounds of calcium silicates $(CaSiO_2)_n$ is called clinker burning. The melted calcium silicates forms a viscous semi-liquid material at these higher temperatures where it forms small balls called clinker, as it slides downward along the inclined rotating kiln. This kiln is rated at 92 tons per hour of clinker. The clinker transfers to the planetary coolers and is sent by elevator to the G-Cooler. The cooled clinker is conveyed for storage in the clinker silos and than to the Clinker Cooler Grinder building where it becomes ground with the addition of gypsum, limestone and flyash to produce Portland cement.

RAW MATERIALS

About 168 tons/hr of raw materials are ground in the raw mill grinder and transferred to the raw mill silos. The ground raw materials are pneumatically conveyed from the storage silos to the pre-calcining tower. The raw materials include limestone, sand, clay, iron ore, iron bearing byproducts, aluminum silicates, natural gravel, fly ash, lime, gypsum, and industrial byproducts containing calcium, silica, iron, and alumna, such as bottom ash, slag and gypsum board. In general, feed stocks containing high concentrations of alkali, organic materials, and metals are avoided. No material regulated as hazardous waste under the Resource Conservation and Recovery Act (RCRA) or as a toxic substance regulated under the Toxic Substances Control Act (TSCA) is accepted as a feed material.

FUELS

Fuels burned in the kiln include: petroleum coke, coal, natural gas, whole tires, and a small amount of internally generated waste lubrication oils. The fuel usage rate is defined by slurry chemistry, fuel availability, and production rate. The nominal heat for clinker production is approximately 4.3×10^6 Btu per ton (Btu/ton). Fuels burned in the kiln provide about 396×10^6 Btu/hr. This allows a clinker production rate of about 2200 tons per day.

MAIN STACK

The kiln exhausts from its upper end in the same area where preheated materials are received from the preheat tower. The exhaust flows up through the 5 stage preheater tower as raw materials cascade down towards to kiln. The exhaust preheats and starts the process of converting the raw materials in the preheat tower. The exhaust ducts back down to ground level where it either routes through the raw mill grinder or is ducted directly to the main baghouse. The exhaust from the main baghouse is sent to the main stack on the side of the preheater tower that is about 250 feet high. Dry gas scrubbing of the exhaust is used at several locations in the exhaust stream.

The main stack is continuously monitored for opacity, SO_2, NO_x, CO, oxygen, temperature and stack flow rate.

Typically stack emissions are about 2 to 4% opacity, about 100 ppm (20 to 30 lb/hr) SO_2, 300 to 400 ppm (300 lb/hr) NO_x, about 500 to 800 ppm (250 lbs/hr) CO, about 7% oxygen, stack temperature of 350 ºF and stack flow of about 170,000 to 180,000 cubic feet per minute.

FINISH PRODUCT

The clinker is processed in the ball mills with gypsum to form cement at about 60 tons per hour and sent to the cement silos for storage. Cement can be shipped by truck, rail or barge.

Each of the (2) Mill Sweep Baghouses in the Finish Mill have 20,000 cfm and each of the (2) High Efficiency Separator baghouses have 77,000 cfm.

OTHER PROCESS CONTROL BAGHOUSES

There are more than 60 fabric filter baghouses including the larger baghouses mentioned that control emissions plant-wide for the cement manufacturing operations. All the baghouses except the main baghouse have a particulate emission standard of 0.005 gr/dscf averaged for a 24 hour period.

Review of Permit Application

An air operating permit application was received from Ash Grove on January 1, 1995. An incompleteness letter from Puget Sound Clean Air Agency was sent on August 2, 1995. Additional information was received on September 5, 1995. A Completeness Determination was made by Puget Sound Clean Air Agency on November 20, 1995, acknowledging the application met the requirements of WAC 173-401-500(7) and it was determined to be complete.

Compliance History

General

This compliance history summarizes enforcement actions noted from July 1, 1997 to the date of this initial draft air operating permit. The Puget Sound Clean Air Agency has inspected Ash Grove annually since 1997. There is one outstanding enforcement action related to asbestos and its status is discussed below.

Ash Grove Source History Table (below) shows each violation, date of violation, regulations or permit conditions cited, violation description, civil penalty number, civil penalty amount, and status. For discussion, the Notices of Violation are organized by violation type as follows:

- Fugitive dust and fallout cases.
- Continuous emission monitoring.
- Asbestos.

Fugitive Dust and Fallout Cases

Fugitive dust enforcement actions consist of dates when an Agency inspector observed dust emissions emanating from plant operations. Fallout enforcement actions are those occurring when an Agency inspector verified off-site particulate nuisance impacts such as clinker fallout impacting a complainant's automobile or property. Generally, emissions were not observed at the plant at the same time off-site fallout nuisance impacts were verified. Due to the similar nature of the fugitive dust and the fallout enforcement actions they were often grouped together in settlement agreements on the condition that Ash Grove improve fugitive dust control measures.

Each settlement agreement pertaining to fugitive dust and fallout is discussed below.

An Assurance of Discontinuance (AOD) signed on December 9, 1998 resolved all of the enforcement actions from July 16, 1997 through August 14, 1998 for Civil Penalty Nos. 8760, 8761, 8801, and 8929. The AOD required Ash Grove to pay $12,000. A condition of the AOD required Ash Grove to hire a consultant to investigate potential fugitive dust sources at the plant and to evaluate improvement projects. The study was completed on November 2, 1999, by David Maars.

The study identified three potential projects to reduce fugitive clinker emissions from the plant:

1. Isolate the head end of the pan conveyor in the g-cooler.
2. Install a baghouse to improve dust capture at the tripper car discharge in the finish mill.
3. Remove ten transfer points on the clinker silo building by converting five open belt conveyors to a drag chain conveyor system.

On March 25, 2002, Ash Grove signed the AOD for Civil Penalty No. 9352. This AOD covered six fallout nuisance notices of violations issued between February 18, 2000 and October 4, 2001. The AOD required Ash Grove to pay $6,000 and comply with the following conditions:

1. Install water suppression systems on barge unloading, raw material conveyors, and raw material stockpiles.

2. Install a new 20,000 CFM dust collector to capture emissions from the clinker storage shed.

On August 9, 2001, Ash Grove signed an AOD for Civil Penalty No. 9120. Ash Grove agreed to pay $2,000 and comply with the following conditions:

1. Implement an amended O&M plan for clinker storage shed dust management practices
2. Allow no unexcused violations of fugitive dust emissions from loader operations in the clinker storage shed for a period of two years after the date of the Consent Order.

Continuous Emission Monitoring

The Agency receives monthly reports from Ash Grove and documents reported violations.

Before September 1998, the Puget Sound Clean Air Agency issued notices of violation for every self-reported exceedance recorded by Ash Grove's continuous emission monitor system (CEMS).

In September 1998, a significant change occurred in the Agency's review of CEMS reports when the Agency developed an interim Civil Penalty policy. The policy was adopted by the Agency's Board of Directors through Resolution No. 962 passed January 10, 2002. This Resolution incorporates a policy based upon the EPA Draft Guidance for High Priority Violations dated July 1998 and includes; Continuous Emission Monitoring Civil Penalty Worksheet and Recommendation, and Emission Monitoring Civil Penalty Gravity Criteria.

The policy elevated chronic repeat violations to "High Priority Violations" status and directed penalties to be assessed for such violations. Pursuant to this policy, the Agency generally closes CEMS violations not meeting the high priority criteria but assesses civil penalties based on the Worksheet and Gravity Criteria for violations meeting the high priority criteria. An example of a high priority violation warranting a civil penalty would be for sulfur dioxide emissions greater than 15% above the emission standard for a period greater than 3% of the equipment operating hours during a reporting month.

Potential CEMS violations fall into the following categories: sulfur dioxide, nitrogen oxide,, carbon monoxide, opacity, and missing data. Each is discussed below. There were no carbon monoxide violations recorded during this period.

Sulfur Dioxide

From July 1997 through March 1998, the Agency issued violations to Ash Grove for excess sulfur dioxide emissions at start up and during normal operations. Ash Grove self-reported these violations in its monthly CEM reports.

Ash Grove requested a permit modification of its SO2 limits at start-up and demonstrated it continued meeting Best Available Control Technology. On June 6, 2001, the Agency issued a revised Order of Approval No. 7381 issuing work practice standards for Ash Grove to control SO2 emissions at startup. The SO2 emission standard during normal operations remained unchanged.

Once Order of Approval No. ____ was changed, the Agency closed all open cases for SO2 emissions at startup with a closure letter dated July 21, 1998. Enforcement actions for SO2 emissions during normal operations were reviewed with the September 10, 1998 interim CEM civil penalty policy which assessed penalties for cases deemed to be significant violators per

EPA. These enforcement actions did not approach significant violator thresholds and were closed by two closure letters, both dated December 18, 1998.

Nitrogen Oxides

From June 1998 to February 2000, the Agency issued violations to Ash Grove for exceeding the nitrogen oxide (NOx) 24-hour and 1-hour emission standards listed in Order of Approval No. 7381. While many unknown factors may cause these emissions, a common reason for many of these exceedances was due to burning natural gas where temperatures are higher and thermal NOx is formed. Thermal NOx is nitrogen oxide formation that occurs with nitrogen in air at high temperatures.

Ash Grove requested a permit modification of its NOx limits and demonstrated it continued meeting Best Available Control Technology. Ash Grove requested that the Agency increase the NOx emission limit and demonstrated they were meeting Best Available Control Technology limits. The Agency issued Order of Approval No. 7381 on June 6, 2001 which raised the 24-hour NOx standard from 501 ppm to 650 ppm and eliminated the 1-hour limit.

All enforcement actions have been resolved through penalty or closure. Resolutions of these enforcement actions are as follows:

- NOV No. 36679 was closed on August 8, 2002 based on the September 10, 1998 interim CEM civil penalty policy.
- NOV No. 36871 was closed on October 28, 1998 based on the September 10, 1998 interim CEM civil penalty policy.
- CP No. 8936 was cancelled on January 27, 1999 because Ash Grove later provided information that the event occurred at start-up and the WAC 173-400-107 exemption was granted.
- CP No. 8937 was issued for $8,000 and was paid on February 19, 1999.
- NOV No. 36682 was closed on March 31, 1999 based on the September 10, 1998 interim CEM civil penalty policy.
- CP No. 8972 was issued for $2,000 and was paid on May 10, 1999.
- CP No. 8985 was issued for $1,000 and paid on December 7, 1999.
- CP No. 8998 was issued for $6,000 and paid on December 28, 1999.
- NOV No. 36741 was closed on July 26, 2001 as a result of the higher limit allowed in the revised Order of Approval No. 7381.
- CP No. 9071 was cancelled on July 30, 2001 as a result of the higher limit allowed in the revised Order of Approval No. 7381.
- CP No. 9095 was resolved through an AOD signed November 1, 2000 as a result of the higher limit allowed in the revised Order of Approval No. 7381.
- CP No. 9053 was issued for $6,000, and CP No. 9079 was issued for $6,000. Both were paid on September 7, 2001.

- ***Carbon Monoxide***

During the last five years there have been no carbon monoxide violations recorded by the CEMS.

Continuous Emission Monitoring- Opacity

The NOV log shows opacity violations issued prior to the September 1998 civil penalty policy. All enforcement actions have been resolved and closed. Since September 1998, Ash Grove has continued to report infrequent opacity excursions on its monthly CEM reports. Either these events have not exceeded the high priority violation criteria, or they have been excused pursuant to WAC 173-400-107. The post September 1998 violations have been documented and closed based on Written Warnings.

Most opacity violations occur when the baghouse malfunctions, due to broken or loose bags. The baghouse contains fabric filter bags that remove particulate prior to the kiln exhaust exiting the main stack. Ash Grove is required to keep an Operations and Maintenance Plan to demonstrate that it is maintaining its equipment in good working order. The Agency continues to review opacity events and maintenance of the baghouse during CEM report reviews and during site inspections.

CEM Missing Data

The Agency issued a series of Notices of Violation to Ash Grove for continuous emission monitoring missing data and for operating the kiln without a quality control plan. The requirements in Regulation I, Section 12.03, effective January 1993, specified a data capture requirement of 90% valid hours of CEM data per day pursuant to Regulation I, Section 12.03(h)(4). On June 1, 1998, the Agency amended the regulation which changed the data capture requirement from 90% per day to 95% per month. As a result of the rule change, the Agency closed the Notices of Violation issued for missing data in July-December 1997. Three violations were issued for missing data in March of 1998. Based upon corrective actions reported, the Agency closed all three cases in a closure letter dated November 2, 1998. During a review of the files conducted for this summary, this letter could not be found. The Agency issued a second case closure letter on August 8, 2002 to ensure that this determination is on file.

Notice of Violation No. 36560 was issued to Ash Grove because it failed to respond to some of the Notices of Violation issued for missing data. The Agency closed this case in a case closure letter dated October 16, 1998 based on the June 1, 1998 rule change that lowered the data capture requirement.

The Notices of Violation issued for operating the kiln without a CEM Quality Control plan were settled under the Assurance of Discontinuance for Civil Penalties No. 8897 and 8899. The AOD was signed by Ash Grove on August 31, 1998. Per the AOD, Ash Grove submitted a CEM quality assurance quality control plan dated December 1, 1998. On September 29, 1999, the Agency sent a letter to Ash Grove accepting the plan and closing Civil Penalties Nos. 8897 and 8899.

Asbestos

NOV No. 4-040305 issued 10/18/01 for an asbestos violation that occurred on October 18, 2001. Ash Grove agreed to submit an asbestos management plan to the Agency as a corrective action response to the Notice of Violation. Puget Sound Clean Air Agency closed this case on 9/12/02. The case closure letter was based on Ash Grove's submittal of the asbestos management plan to the Agency.

Ash Grove Compliance Source History Table

NOV #	Date of Violation	Citation	Violation Description	CP #	AMT.	Status (CCL – Case Closure Letter)
Fallout and Fugitive Dust Violations Settled Per David Maars Fugitive Dust Study						
37062	7/16/97	9.15I, 9.20 [I]	Dust from white fly ash silo	8761	$3,000	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99
37063	7/16/97	9.20 [I]	Holes in shrink wrap	8761	$3,000	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99
36863	7/16/97	9.11(a)[I]	Fallout	8801	$8,000	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99
36861	8/7/97	9.15(c), 9.20 [I]	Holes in shrink wrap	8760	$8,000	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99
36864	9/8/97	9.11(a)[I]	Fallout	8801	$8,000	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99
37442	4/27/98	9.11(a)[I]	Fallout	No CP	None	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99; No CP assessed incorporated into AOD
37444	4/29/98	9.11(a)[I]	Fallout	No CP	None	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99; No CP assessed incorporated into AOD
37075	8/14/98	9.15(a), 9.20	Fugitive Emissions	8929	$3,000	AOD signed 12/9/98, Paid 12/23/98, Study Completed 11/2/99
Fallout and Fugitive Dust Violations						
36694	2/18/00	9.11(a)[I]	Fallout Nuisance	9352	$12,000	AOD signed 3/25/02, Paid 5/6/02
36740	9/22-23/00 (verified 9/26/00)	9.11(a)[I]	Fallout Nuisance	9352	$12,000	AOD signed 3/25/02, Paid 5/6/02
37085	11/21/00	9.15(a) [I]	Fugitive Dust	9120	$3,000	AOD signed 8/9/01, Paid 9/17/01
36739	12/6/00	9.11(a)[I]	Fallout Nuisance	9352	$12,000	AOD signed 3/25/02, Paid 5/6/02
36879	12/21-24/00	9.11(a)[I]	Fallout Nuisance	9352	$12,000	AOD signed 3/25/02, Paid 5/6/02
3-001656	8/7/01	9.11(a)[I]	Fallout Nuisance	None	$12,000	AOD signed 3/25/02, Paid 5/6/02
3-000302	10/4/01	9.11(a)	Fallout Nuisance	9352	$12,000	AOD signed 3/25/02, Paid 5/6/02

NOV #	Date of Violation	Citation	Violation Description	CP #	AMT.	Status (CCL – Case Closure Letter)
Sulfur Dioxide CEM Violations Start Up and Normal Operations						
36238	7/10/97	OA 5730 #7	S–2 - startup	None	None	CCL 7/21/98
36239	7/11/97	OA 5730 #7	S–2 - startup	None	None	CCL 7/21/98
36240	7/26/97	OA 5730 #7	S–2 - startup	None	None	CCL 7/21/98
35792	8/25/97	OA 5730 #7	SO2 main stack	None	None	CCL 7/21/98
36565	10/2/97	OA 5730 #7	Startup SO2 kiln	None	None	CCL 7/21/98
36566	10/3/97	OA 5730 #7	Startup SO2 kiln	None	None	CCL 7/21/98
36567	10/10/97	OA 5730 #7	Startup SO2 kiln	None	None	CCL 7/21/98
36578	11/11/97	OA 5730 #7	Startup SO2 kiln	None	None	CCL 7/21/98
36579	11/26/97	OA 5730 #7	Startup SO2 kiln	None	None	CCL 7/21/98
36580	11/27/97	OA 5730 #7	Startup SO2 kiln	None	None	CCL 7/21/98
36581	11/28/97	OA 5730 #6c	SO2 normal op of kiln	None	None	CCL 12/18/98
36598	1/29/98	OA 5730 #7	Startup SO2 kiln	None	None	CCL 7/21/98
36713	3/8/98	OA 5730 #6c	SO2 main stack	None	None	CCL 12/18/98
Nitrogen Oxide CEM Violations						
36679	5/25/98	OA 5730 #6b	NOx 24 hr standard	None	None	CCL 8/08/02
36866	6/7/98	OA 5730 #6b	NOx > 501 ppm 24 hr. Ave	8936	None	Cancelled 1/27/99
36867	6/10/98	OA 5730 #6b	NOx > 501 ppm 24 hr. Ave and NOx > 700 ppm 1 hr.	8937	$8,000	Paid 2/19/99
36868	6/11/98	OA 5730 #6b	NOx > 501 ppm 24 hr. Ave and NOx > 700 ppm 1 hr.	8937	$8,000	Paid 2/19/99
36869	6/12/98	OA 5730 #6b	NOx > 501 ppm 24 hr. Ave and NOx > 700 ppm 1 hr.	8937	$8,000	Paid 2/19/99
36870	6/13/98	OA 5730 #6b	NOx > 501 ppm 24 hr. Ave and NOx > 700 ppm 1 hr.	8937	$8,000	Paid 2/19/99
36871	6/27/98	OA 5730 #6b	NOx > 501 ppm 24 hr. Ave and NOx > 700 ppm 1 hr.	None	None	CCL 10/28/98
36721	10/15&30/98	OA 7183 #5b	NOx	8972	$2,000	Paid 5/10/99
36725	11/3/98 11/12/98 11/27/98	OA 7381 #5b OA 7381 #5b OA 7381 #5b	NOx 8 hr NOx 24 hr NOx 8 hr NOx 24 hr NOx 1 hr avg	8985	$1,000	Paid 12/7/99; (check # 55712)

NOV #	Date of Violation	Citation	Violation Description	CP #	AMT.	Status (CCL – Case Closure Letter)
36682	12/98	OA 7381 #5b	NOx 24 hr	None	None	CCL 3/31/99
36726	1/99	OA 7381 #5b	NOx 24 hr 501 ppm	8998	$6,000	Paid 12/28/99
36727	3/3/¾3/4/¾3/4/99 3/5/99 3/5/99 3/6/99 3/6/99 3/8/99 3/8/99 3/12/99 3/12/99	OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b OA 7381 #5b	NOx 2 hr NOx 3 hr NOx 24 hr NOx 24 hr NOx 3 hr NOx 24 hr NOx 2 hr NOx 24 hr NOx 4 hr NOx 24 hr NOx 3 hr	8998	$6,000	Paid 12/28/99
36687	11/25/99 11/25/99 11/25/99 11/26/99 11/26/99	OA 7381 #(6)(d) OA 7381 #(5)(b) OA 7381 #(5)(b) OA 7381 #(5)(b) OA 7381 #(5)(b)	NOx NOx NOx NOx NOx	9053	$6,000	Paid $6,000 9/7/01
36690	2/15/00	OA 7381 #(5)(b)	NOx 24 hr	9071	$3,000	Cancelled 7/30/01
36734	3/19/00 3/20/00 3/25/00 3/28/00	OA 7381 #(5)(b) OA 7381 #(5)(b) OA 7381 #(5)(b) OA 7381 #(5)(b)	NOx 24 hr NOx 24 hr NOx 24 hr NOx 24 hr	9095	$2,000	AOD signed 11/1/00; all penalties suspended (no payment) AOD Completed with C½1/2/01
36741	10/12/00	OA 7381 #(5)(b)	NOx 24 hr avg 501 ppm	None	None	CCL 7/26/01
Opacity CEM Violations						
36583	11/1/97	9.09(b)(2)[I]	>5% opacity 1 hr avg	8886	$8,000	Paid 8/25/98
36584	11/2/97	9.09(b)(2)[I]	>5% opacity 1 hr avg	8886	$8,000	Paid 8/25/98
36585	11/22/97	9.09(b)(1)[I]	>20% opacity 3 min	8886	$8,000	Paid 8/25/98
36597	12/4/97	9.09(b)(1)[I] 9.09(b)(2)[I]	> 20% opacity 3 min >5% opacity 1 hr avg	None	None	CCL 5/5/98; Excusable per WAC
36708	2/1/98	9.09(b)(1)[I]	>20% opacity 3 min	None	None	CCL 4/16/98
36714	3/26/98	9.09(b)(1)[I] 9.09(b)(2)[I]	>20% opacity 3 min >5% opacity 1 hr avg	None	None	CCL 12/18/98
36710	4/3/98	9.09(b)(2)[I]	>5% opacity 1 hr avg	None	None	CCL 12/18/98

NOV #	Date of Violation	Citation	Violation Description	CP #	AMT.	Status (CCL – Case Closure Letter)
36711	4/22/98	9.09(b)(2)[I]	>5% opacity 1 hr avg	None	None	CCL 12/18/98
36712	4/25/98	9.09(b)(2)[I]	>5% opacity 1 hr avg	None	None	CCL 12/18/98
Continuous Emission Monitoring Missing Data						
37408	7/14/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37409	7/14/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37410	7/14/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
37411	7/15/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37412	7/15/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37413	7/15/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
37414	7/21/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37415	7/21/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37416	7/21/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
37417	7/22/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37418	7/22/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37419	7/22/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
37420	7/23/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37421	7/23/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37422	7/23/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
37423	7/25/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37424	7/25/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37425	7/25/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
37426	7/28/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37427	7/28/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37428	7/28/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
37429	7/30/97	12.02(c), 12.03(h)(4) [I]	SO2 missing data	None	$4,000	CCL 5/19/98
37430	7/30/97	12.02(c), 12.03(h)(4) [I]	CO missing data	None	$4,000	CCL 5/19/98
37431	7/30/97	12.02(c), 12.03(h)(4) [I]	NOx missing data	None	$4,000	CCL 5/19/98
36559	7/30/97 – 11/18/97	OA 5730 #4; OA 5730 #8 12.02(a)(1)[I]	No QAQC CEM Plan	8897	$3,000	AOD signed 8/31/98; Paid 9/10/98; QA/QC Plan Completed 9/29/99
35793	8/5/97	12.02(c)[I}	Missing data	None	None	CCL 5/19/98
35794	8/12/97	12.02(c)[I]	Missing data	None	None	CCL 5/19/98
35795	8/13/97	12.02(c)[I]	Missing data	None	None	CCL 5/19/98

NOV #	Date of Violation	Citation	Violation Description	CP #	AMT.	Status (CCL – Case Closure Letter)
35796	8/18/97	12.02(c)[I]	Missing data	None	None	CCL 5/19/98
36560	8/18/97-11/18/97	3.09(a), 3.11(b) [I]	Failure to Respond	None	None	CCL 10/16/98
36561	9/29/97-11/18/97	3.09(a), 3.11(b) [I]	Failure to Respond	8899	$2,000	AOD signed 8/31/98; Paid 9/10/98; QA/QC Plan Completed 9/29/99
36586	11/4/97	12.02(a)(1) 12.02(c)(1)[I]	Missing data	None	$4,000	CCL 5/19/98
36587	11/12/97	12.02(a)(1) 12.02(c)[I]	Missing data	None	$4,000	CCL 5/19/98
36594	12/1/97	12.02(a)[I]	Missing data	None	None	CCL 5/19/98
36595	12/2/97	12.02(a)[I]	Missing data	None	None	CCL 5/19/98
36596	12/3/97	12.02(a)[I]	Missing data	None	None	CCL 5/19/98
367¾3/4/98	OA 5730 #8 12.02c[I]	Missing CEM data	None	None	CCL 11/2/98 (lost); reissued CCL 8/8/02	
36716	3/16/98	OA 5730 #8 12.02c[I]	Missing CEM data	None	None	CCL 11/2/98 (lost); reissued CCL 8/8/02
36717	3/17/98	OA 5730 #8 12.02c[I]	Missing CEM data	None	None	CCL 11/2/98 (lost); reissued CCL 8/8/02
CEM Violation- Late Report Rescinded						
3-001519	5/6/2002	12.03 (f) [I]	Issued for late March 2002 CEM Report due 5/1/02. Report dated 4/29/02 found in Agency files. Source in compliance.	None	None	Rescinded Notice of Violation 5/6/02
Asbestos Violation						
4-040305	10/18/01	4.02(a), 4.03(a), 4.04(a), 4.05(a), 4.05(b)(1), 4.05(b)(4), 4.05(b)(7), 4.05(b)(9), 4.05(b)(10).	Asbestos Violations	Pending	Pending	CP Recommended 8/8/02

Emission Inventory

The annual emissions reported to Puget Sound Clean Air Agency by Ash Grove for 1995 through 2001 are tabulated below. The main pollutants emitted from this plant are CO and NOx calculated as NO_2, although SO_2 emissions exceed 100 tons per year primarily from burning coal. Emissions are based on source test data, EPA AP-42 emission factors and continuous emission monitoring systems. Ash Grove has supplied particulate emission data based on source tests from 1996.

Air Contaminant Emission Summary

TOTAL EMISSIONS							
Pollutants Tons =>	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
CO	1,310	1,354	1,599	1,585	1,412	1,477	1,139
NO2	1,058	959	910	1,203	1,253	1,282	1,198
PM10	53	53	51	52	52	51	46
PM2.5	0	28	27	0	0	18	16
SO2	74	171	188	181	157	106	129
Cement Kiln Dry Process with BHs							
Pounds =>	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
CO	2,403,240	2,485,200	2,943,000	2,916,140	2,587,460	2,708,800	2,100,000
NO2	1,941,160	1,759,400	1,675,600	2,212,820	2,295,620	2,351,600	2,210,000
PM10	57,691	57,802	56,424	59,076	59,773	58,333	52,566
PM2.5	0	31,851	31,092	0	0	10,568	9,523
SO2	136,440	313,200	346,000	332,280	287,940	195,000	238,000
Coal Mills							
Pounds=>	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
CO	217,622	223134	254,441	254,659	237,413	245,078	177,034
NO2	175,779	157,968	144,866	193,240	210,636	212,760	186,308
PM10	3,312	3,284	3,162	3,194	3,356	3,309	3,083
PM2.5	0	1,810	1,742	0	0	490	456
SO2	12,355	28,121	29,966	29,017	26,420	17,643	20,064
Limestone Transfer with BH							
Pounds=>	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
CO	0	0	0	0	0	0	0
NO2	0	0	0	0	0	0	0
PM10	5,748	5,608	5,333	5,507	5,583	5,533	4,931
PM2.5	0	2,908	2,767	0	0	3,320	2,959
SO2	0	0	0	0	0	0	0
Raw Mill Separator with BH							
Pounds =>	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
CO	0	0	0	0	0	0	0
NO2	0	0	0	0	0	0	0
PM10	4,907	4,704	4,626	4,792	4,822	4,755	4,258
PM2.5	0	2,442	2,400	0	0	2,853	2,555
SO2	0	0	0	0	0	0	0

Finish Grinding Feed Belt with BH

Pounds =>	1995	1996	1997	1998	1999	2000	2001
CO	0	0	0	0	0	0	0
NO2	0	0	0	0	0	0	0
PM10	6,333	6,345	6,193	6,525	6,600	6,041	5,444
PM2.5	0	3,296	3,212	0	0	3,624	3,266
SO2	0	0	0	0	0	0	0

Finish Grinding Mill Air Separator with BH

Pounds =>	1995	1996	1997	1998	1999	2000	2001
CO	0	0	0	0	0	0	0
NO2	0	0	0	0	0	0	0
PM10	27,555	27,836	25,508	25,384	24,840	24,170	21,471
PM2.5	0	14,449	13,242	0	0	14,502	12,883
SO2	0	0	0	0	0	0	0

Ash Grove did not supply an estimate of plant-wide fugitive emissions in their application.

Puget Sound Clean Air Agency estimated the fugitive dust emissions from Ash Grove Cement in a January 5, 1990 PM10 Addendum for the PM10 SIP for Seattle, Tacoma, and Kent Non-attainment areas. However, at that time, the plant was not converted to its present configuration and status. Production was significantly lower than its current potential.

Explanation of Applicable Requirements

Applicable requirements are listed in several sections of this operating permit as outlined below. The permit only lists the requirements that the Puget Sound Clean Air Agency has determined to be within the scope of the definition of “applicable requirements” under the operating permit program. Ash Grove is legally responsible for complying with all applicable requirements of the operating permit as well as other requirements that do not fit the definition of “applicable requirements” found in Chapter 173-401 Washington Administrative Code (WAC). Some of the applicable requirements contain terms or monitoring, maintenance and recordkeeping that require detailed explanation in this statement of basis. The specific conditions are listed below, along with any necessary explanations in monitoring, maintenance, and recordkeeping requirements.

Applicable Requirements

Ash Grove is subject to all the requirements listed in Section I of the operating permit. Section I.A contains the requirements that are applicable facility-wide, and Section I.B contains requirements applicable only to specific emission units or groups of emission units. The requirements in Section I.B only apply to the specific emission units cited; however, the requirements in Section I.A also apply to the specific emission units or activities described in Section I.B unless specifically state otherwise in the permit. If the monitoring, maintenance, and recordkeeping method for any requirement in Section I.A is more extensive for specific emission units, that requirement is repeated in Section I.B with the additional monitoring, maintenance and recordkeeping requirements.

Section I.A. (Facility-Wide)

The table lists the citation for the "applicable requirement" in the second column. The third column (Date) contains the adoption or effective date of the requirement. In some cases, the effective dates of the Federally Enforceable, or "SIP[1]" Requirement and the Non-Federally Enforceable, or "State/Local Only" Requirement are different because only rules approved by EPA through Sections 110, 111, and 112 of the federal Clean Air Act are federally enforceable, and either the state has not submitted the regulation to the EPA or the EPA has not approved it.

The first column is used as an identifier for the requirement, and the fourth (Requirement Paraphrase) column paraphrases the requirement. The first and fourth columns are for information only and are not enforceable conditions of this operating permit. The actual enforceable requirement is embodied in the requirement cited in the second and third columns.

The fifth column (Monitoring, Maintenance & Recordkeeping Method) identifies the methods described in Section II of the operating permit. Following these methods is an enforceable requirement of this permit. The sixth column identifies the averaging time for the reference test method. The last column (Reference Test Method) identifies the reference method associated with an applicable emission limit that is to be used if and when a source test is required. In some cases where the applicable requirement does not cite a test method, one has been added.

In the event of conflict or omission between the information contained in the fourth and sixth columns and the actual statute or regulation cited in the second column, the requirements and language of the actual statute or regulation cited shall govern. For more information regarding any of the requirements cited in the second and third columns, refer to the actual requirements cited.

Recently amended Puget Sound Clean Air Agency Regulations. The Puget Sound Clean Air Agency Board of Directors has recently amended several sections of its regulations. These amended sections are listed as State/Puget Sound Clean Air Agency Enforceable Requirements in the operating permit. The versions of the regulations that are in the SIP are listed as Federally Enforceable Requirements. The amended versions will be (or in some cases have been) forwarded to EPA as SIP amendments. Upon approval of the SIP changes, the revised versions of the regulations will be federally enforceable and the old version will no longer apply.

[1] "SIP" means "state implementation plan" which is a plan for improving or maintaining air quality and complying with the Federal Clean Air Act. The Federal Clean Air Act requires states to submit these plans to the US EPA for its review and approval. This plan must contain the rules and regulations of the state agency or local air authority necessary to implement the programs mandated by Federal law. Once the EPA adopts the plan or elements of it, the plan and its requirements become "federally enforceable" by EPA. New or modified state or local rules are not federally enforceable until they are "adopted into the SIP" by the EPA.

Facility-wide Inspections. Most of the facility-wide requirements that require monitoring refer to facility-wide monitoring procedures that vary in form, scope of monitoring observations, and frequency. The Puget Sound Clean Air Agency recognizes the complexity of the facility and the large number of small emission units that are located at Ash Grove. Because of the large number of emission points at the facility, the practicality of the monitoring methods and frequency have been tailored to reflect the compliance challenges to the level of effort necessary to determine compliance with the requirements included in the permit. For emission units with more potential for being out of compliance with air pollution requirements or where noncompliance can have more significant impacts, the Agency has included specific monitoring procedures appropriate for those units. Facility-wide inspections are intended to augment equipment-specific monitoring and to assure Ash Grove is aware of general activities occurring on the plant site. The Puget Sound Clean Air Agency anticipates that the various monitoring and inspection activities identified in the permit will completed by trained personnel that are familiar with the plant, the permit, and the underlying nature of the requirements included in the permit.

1. Requirements I.A.1 and I.A.2 - 20% General Opacity

Both Puget Sound Clean Air Agency Regulation I, Section 9.03 and WAC 173-400-040(1) standards are 20% opacity and apply to all stationary sources.

Both Section 9.03 (effective date - 3/11/99) and WAC 173-400-040(1) (effective date - 9/15/01) are currently not federally enforceable but will be federally enforceable upon their adoption into the SIP. Previous versions of these regulations have been adopted into the SIP. These provisions have not been included in the operating permit at this time because there are no substantive differences between the SIP adopted versions and these versions awaiting approval. If a version of these regulations were adopted into the SIP which contained a substantive difference from the requirements included in this draft permit, the permit would need to be reopened to incorporate the changes.

The monitoring method is based on monthly facility-wide inspections of some emission points at the Ash Grove. These facility-wide inspections include checking for visible emissions, with Ash Grove taking corrective action or using the reference test method, WDOE Method 9A, to determine opacity if any visible emissions are noted. Recording of visible emissions is not necessarily a deviation of the opacity requirements. However, failure to take timely corrective action, as defined by the monitoring method, is a deviation of the specific operating permit term and may also be an indication of other compliance issues (e.g. Operation & Maintenance (O&M) failures or good working order requirements identified in I.A.14 and I.A.15). Taking corrective action does not relieve Ash Grove from the obligation to comply with the opacity requirement itself. The monitoring procedures are used for several emission limitations and requirements throughout the permit, which are discussed below. The Puget Sound Clean Air Agency has determined that the monitoring should be monthly for the reasons listed below.

1. <u>Initial compliance.</u> There have been no NOVs issued in the last five years for failure to meet this requirement. Ash Grove is presumed to be able to comply with this opacity requirement (see Compliance History).

2. <u>Margin of compliance.</u> Ash Grove handles and transfers over a million tons of dry dusty material each year that has a high potential for fugitive dust emissions. If opacity

problems are observed, operations or maintenance problems are the most likely cause and must be addressed quickly by following and upgrading the O&M Plan to avoid emissions that would have a significant environmental impact. There have been no recent opacity problems observed by the Puget Sound Clean Air Agency and the sources are well controlled with a good O&M Plan. The Agency concludes that the margin for opacity compliance is large enough to justify visual inspections at a monthly frequency. By following this monitoring frequency, Ash Grove will take corrective action before a violation occurs. Recording of visible emissions is not necessarily a deviation of the opacity requirements. However, failure to take timely corrective action, as defined by the monitoring method, is a deviation of the specific permit term. Taking corrective action does not relieve Ash Grove from the obligation to comply with the opacity requirement itself.

3. Variability of process and emissions. The equipment operates on a relatively constant production rate, both during a per-shift basis and during a per-hour basis, so emissions can be expected to be relatively constant during the time period of the emission standard.

4. Environmental impacts of problems. Generally, any observed opacity is related to emissions of particulate matter or finely divided liquid droplets. If opacity problems are observed, operations or maintenance problems are the most likely cause and must be addressed quickly by following and upgrading the O&M Plan to avoid emissions that would have a significant environmental impact. There have been some relatively recent issues associated with clinker dust complaints which have some indirect relationship to this plant-wide opacity standard. The resolution of the most recent enforcement case for those violations required the installation of some improved dust collection and control measures. This monitoring procedure will include verification that those devices and measures are effectively managed. While this monitoring procedure is based on facility wide observations, it is most appropriate for use on point sources and process units. The permit includes other, additional monitoring procedures for fugitive dust and complaint related topics.

5. Technical considerations. Ash Grove is required to perform monthly self-inspections. By following this inspection frequency, following a good O&M Plan, and by making corrections and modifications to this plan, Ash Grove will likely avoid catastrophic failure of the air pollution generating or controlling equipment which is the main cause of opacity standard deviations at Ash Grove. Catastrophic failure of specific air pollution generating equipment is the most likely sources of an opacity standard deviation at Ash Grove. Additional monitoring procedures for specific emission units are specified in the operating permit.

2. Requirements I.A.3, I.A.4, I.A.5 Particulate Concentration

Section 9.09(a) (effective date - 2/10/94) and WAC 173-400-060 (effective date - 3/22/91) are federally enforceable.

Section 9.09 (effective date - 4/9/98) and WAC 173-400-060 (effective date - 8/21/98) are currently not federally enforceable but will be federally enforceable upon their adoption into the SIP.

Puget Sound Clean Air Agency Regulation I, Section 9.09 (effective date - 2/10/94) limits the particulate emissions to 0.05 gr/dscf and WAC 173-400-060 (effective date - 3/22/91) limits the particulate emissions to 0.1 gr/dscf. Both requirements apply to all equipment used in a manufacturing process and general process units, uncorrected for excess air.

Puget Sound Clean Air Agency Regulation I, Section 9.09 (4/9/98) limits the particulate emissions to 0.05 gr/dscf from equipment used in a manufacturing process.

WAC 173-400-060 limits particulate emissions to 0.1 gr/dscf from general process units (i.e., units using a procedure or a combination of procedures for the purpose of causing a change in material by either chemical or physical means, excluding combustion).

For these facility-wide requirements, the monitoring method is based on visual inspections once-per-month of general air pollution generating equipment at Ash Grove not covered by Emissions Unit Specific Applicable Requirements (I.B), with Ash Grove taking corrective action within 24 hours of the initial observation until there are no visible emissions or, alternatively, recording the opacity using the reference test method or shutting down the unit or activity until it can be repaired. Because particulate and opacity are in general physically related, the particulate monitoring for this requirement is the same as opacity (see the discussion for Requirements I.A.1 and I.A.2 in this document).

In Condition I.A.5, the emission limit of 0.005 gr/dscf identified in Order of Approval No. 7381, Condition No. 4 has been included in the operating permit as a facility wide requirement. This Order, as well as some additional orders for Ash Grove which followed it, were the result of PM-10 SIP plan requirements. This Order applied to each baghouse, excluding the main kiln baghouse that existed at Ash Grove when it was originally approved. Subsequent Order modifications have brought the current approval date up to June 6, 2001. Ash Grove has agreed that this order effectively applies to all emission units controlled by a baghouse (excluding the main kiln) at the plant and the impact on each unit is the same. All of the subject baghouses are managed to a “no visible emission” expectation and any unit which does have visible emissions is assumed to be malfunctioning on some level. This Order was issued on the basis that an observation of “no visible emissions” from a baghouse was sufficient to demonstrate compliance with this low concentration. The order provided alternative, incremental observation procedure options to demonstrate compliance.

These identified options require Ash Grove to use one of the following:

- Puget Sound Clean Air Agency approved source test
- No visible emissions for 15 consecutive seconds
- No visible emissions for 3 consecutive minutes
- Repairing the baghouse with visible emissions for more than 3 minutes within 24 hours

The first option is always available, but not expected to be routinely used. The next three are intended to provide a progressive option to respond to a visible emission condition and still maintain compliance. If an observer looked at the exhaust point and saw no visible emissions for 15 consecutive seconds that would represent compliance with this condition for that observation. If the observer saw a short period of visible emissions, observations could continue and if the visible emission condition ceased, and the observer maintained the observation (and record) for 3 consecutive minutes with no visible emissions observed, that again would represent a compliant observation. If the visible emission condition exceeded the 3 consecutive minute criteria, then the observer/operator must repair the baghouse or shut the process down until the baghouse is repaired and no visible emissions are observed upon restart.

For these baghouses, the existence of sustained visible emissions (either observed by Ash Grove or this Agency) can serve as the basis for this Agency to require Ash Grove to complete a compliance source test on the unit involved. The monitoring procedure to verify operation of the units without visible emissions will effectively satisfy the compliance with this Order.

3. Requirement I.A.6 - SO_2 Concentration

Both Puget Sound Clean Air Agency Regulation I, Section 9.07 (effective date - 4/14/94) which is federally enforceable, and WAC 173-400-040(6) (effective date - 9/20/93) are equivalent requirements (SO_2 emissions not to exceed 1000 ppm), except for the second paragraph of the WAC 173-400-040(6) which is not in the Puget Sound Clean Air Agency regulation. That paragraph, which is not federally enforceable, allows for exceptions to this requirement if the source can demonstrate that there is no feasible method of reducing the SO_2 concentrations to 1000 ppm. Since the Puget Sound Clean Air Agency rules do not allow the exception, this option does not apply to Ash Grove.

WAC 173-400-060 (effective date - 9/15/01) will become federally enforceable upon its adoption into the SIP. This provision has not been included in the operating permit at this time because there are no substantive differences between the SIP adopted version and this version awaiting approval. If a version of this regulation was adopted into the SIP which contained a substantive difference from the requirement included in this draft permit, the permit would need to be reopened to incorporate the changes.

The facility-wide activities at Ash Grove that contribute to sulfur emissions include facility-wide burning of pipeline quality natural gas (not including the kiln).

SO_2 from facility-wide burning of pipeline quality natural gas.

"Natural gas" means a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the Washington Utilities and Transportation Commission. Natural gas may also be referred to as "pipeline quality natural gas." Ash Grove receives the same natural gas as all of the other natural gas consumers, private and industrial, in the Northwest. According to Section 1.4-3 of AP-42, natural gas contains approximately 2000 grains of sulfur per million cubic feet, which is equivalent to approximately 3.4 parts of sulfur per million cubic feet of natural gas, as shown in the following calculation:

$$\frac{2{,}000\,gr\,S}{1{,}000{,}000\;ft^3\;nat.gas}\times\frac{1lb}{7000\,gr}\times\frac{385\,\frac{ft^3}{mole\,S}}{32\,\frac{lb}{mole\,S}}=3.44\times10^{-6}\,\frac{ft^3\,S}{ft^3\;nat.gas}\equiv3.44\;\;ppmdv\,S$$

According to *Perry's Chemical Engineer's Handbook*, each cubic foot of natural gas requires approximately 10 cubic feet of air for combustion, yielding approximately 11 cubic feet of combustion exhaust gases, consisting mostly of nitrogen, water vapor, and carbon dioxide. The sulfur in the natural gas will almost all be converted to sulfur dioxide, with each cubic foot of sulfur producing the same volume of sulfur dioxide. Since each cubic foot of natural gas contains 3.44×10^{-6} cubic feet of sulfur, each cubic foot of stack exhaust will contain approximately:

$$3.44\times10^{-6}\,\frac{ft^3\,S}{ft^3\;nat.gas}\times\frac{1\,ft^3\,SO_2}{1\,ft^3\,S}\times\frac{1\,ft^3\;nat.gas}{11\,ft^3\;stack\,exhaust}=0.313\times10^{-6}\,\frac{ft^3\,SO_2}{ft^3\;stack\,exhaust}$$

The burning of natural gas generates about 0.31 ppmdv SO_2. This estimated value is less than one-tenth of one percent of the 1,000 ppm SO_2 standard.

Therefore, on a facility-wide basis (except for the kiln), it is reasonable to assume that the combustion of natural gas will not exceed the 1,000 ppm SO_2 limits in Puget Sound Clean Air Agency Regulation I, Section 9.07 and WAC 173-400-040(6).

SO_2 from facility-handling of raw and finished materials.

Except for the main stack, the area wide sources of raw materials and finished products do not contain sufficient amount of sulfur to create concentrations of sulfur or sulfur dioxide in such quantities as to have any potential to be close to the emissions standard. Also, except for the kiln there are no other combustion sources that potentially oxidize sulfur to sulfur dioxide.

Therefore, this operating permit does not contain additional monitoring requirements for sulfur dioxide emission other than the main stack.

The remaining federally enforceable requirements in Section I.A. do not contain Emission Standard Reference Test Methods or an Emission Standard Period. The Puget Sound Clean Air

Agency has determined they are not necessary for these requirements. The Puget Sound Clean Air Agency will use the results of monitoring and observations, the review of operation and maintenance procedures and other information available to determine compliance with these requirements.

4. Requirements I.A.7 and I.A.8 – Nuisance Standards

Puget Sound Clean Air Agency Regulation I, Section 9.11 (effective date - 6/9/83) and WAC 173-400-040(5) (effective date - 9/20/93) are federally enforceable.

Puget Sound Clean Air Agency Regulation I, Section 9.11 (effective date - 3/11/99) and WAC 173-400-040(5) (effective date - 9/15/01) are currently not federally enforceable but will be federally enforceable upon their adoption into the SIP. These provisions have not been included in the operating permit at this time because there are no substantive differences between the SIP adopted versions and these versions awaiting approval. If a version of these regulations were adopted into the SIP which contained a substantive difference from the requirements included in this draft permit, the permit would need to be reopened to incorporate the changes.

RCW 70.94.040 also requires that a source shall not cause air pollution in violation of 70.94 RCW or any ordinance, resolution, rule or regulation adopted there under. This provision is not federally enforceable.

WAC 173-400-040(2) (effective date - 9/15/01) prohibits the emission of particulate matter from Ash Grove to be deposited beyond the property line in sufficient quantity as to unreasonably interfere with the use and enjoyment of the property upon which the material is deposited. This provision is not federally enforceable.

WAC 173-400-040(4) (effective date - 9/15/01) requires Ash Grove to use recognized good practices to control odors in order to avoid unreasonably interfere with the use and enjoyment of property. This provision is not federally enforceable.

The monitoring methods are based on a combination of both weekly and monthly plant inspections and responding to complaints to identify possible causes of emissions, including the deposition of particulate, that may unreasonably interfere with the use and enjoyment of property, correcting any problems identified and initiating corrective actions with preventative maintenance as a result of the inspections or investigations. Receiving complaints does not necessarily mean Ash Grove is in violation of this requirement but triggers action by Ash Grove to prevent a violation.

Ash Grove handles or processes over a million tons per year of dry fine dusty materials associated with the production of cement which has a large potential to become air borne even with the best equipment and the best practices to prevent such emissions. However, plant-wide, most materials are handled or processed inside or within buildings or within covered areas that are totally or significantly enclosed. All roadways and parking lots are paved and maintained in relatively clean condition. There have also been significant efforts and expenditures by this plant in an attempt to identify, predict and contain the releases of materials that may likely lead to violations of this regulation.

Even with good operations and maintenance there remains a potential for some releases of fugitive dust that may be in sufficient quantities and of such characteristics and duration as is, or is likely to be, injurious to human, plant or animal life, or property, or which unreasonably interferes with enjoyment of life and property.

During the last five years, the Puget Sound Clean Air Agency has issued ten notices of violation of this regulation (Puget Sound Clean Air Agency Regulation I, Section 9.11). Specifically, these violations were based on complaints of property damage that were verified by the Agency to be caused by fallout of clinker particulate originating from this cement plant and depositing on property. All outstanding violations have been settled and closed with signed assurances of discontinuances. However, to date the Agency has not conclusively determined or identified a particular area, a specific activity or piece of equipment that is responsible for these emissions.

The monitoring method identified in Section II.A.3 (Rooftop Inspections) specifies visual inspections of the plant site (facility-wide) on a weekly basis to discover, control, and repair sources of fugitive dust emissions and specifically identify and control releases or emissions of clinker particulate. The proactive periodic inspection and maintenance frequency before complaints are received, and the addition of the Complaint Response Program (see Section II.A.2 of the permit) which is in effect at all times, represents a combined method for monitoring and assuring compliance. An additional supporting monitoring method for compliance with these requirements is the O&M Plan Inspections (see Section II.A.4 of the permit) which requires a monthly inspection of the plant equipment. The O&M Plan Inspections are intended to identify equipment operations and maintenance issues which could lead to a nuisance related event and prevent such an event.

The Puget Sound Clean Air Agency has determined that weekly monitoring for sources of fugitive dust emissions facility-wide and specifically monitoring for potential releases of clinker dust, as well as full implementation of the Complaint Response Plan and the O&M Plan inspections are together, appropriate monitoring, recordkeeping, and reporting for this requirement for the following reasons.

1. <u>Initial compliance.</u> Ash Grove has generally been careful to maintain equipment to avoid the generation and emission of particulate that can lead to fallout of materials and nuisance complaints. Although there has been a long history of particulate fallout related issues with this plant, Ash Grove is considered to be capable of maintaining compliance with this standard on a continuous basis. Ash Grove has implemented a Complaint Response Program which has effectively been dealing with nuisance issues in the vicinity of the plant. The recent complaint history indicates this source must be diligent and

aggressive in monitoring (both through the Rooftop Inspections and the O&M Plan Inspections), and be proactive to assure compliance is maintained with this requirement.

2. Margin of compliance. Ash Grove daily handles and processes tons of dry dusty materials and, therefore, has significant potential to cause general fugitive dust emissions as well as potential visible source emissions that can cause an environmental nuisance. Although all the roadways and parking lots are paved within the Ash Grove plant boundary and all significant emission points are operated correctly, the fact that there have been ongoing enforcement actions for complaint issues shows that there is very little margin of compliance for the generation of air contaminant emissions in sufficient quantities to be injurious or to unreasonably interfere with enjoyment of life and property. The margin for compliance is considered to be small. However, with aggressive attention to proactive monitoring, developing and following the Compliant Response Program, and performing both the rooftop inspections weekly and the O&M plan inspections monthly for nuisance emission issues (with an emphasis on dust), Ash Grove is anticipated to be able to maintain compliance with this standard.

3. Variability of process and emissions. Because the manufacturing process is relatively constant, it is unlikely that the variability of the process itself will cause emissions leading to environmentally detrimental problems or cause nuisances while the plant is normally operating except during upset conditions.

4. Environmental impacts of problems. While there may be significant potential environmental impacts of emissions that may be environmentally detrimental or potentially can cause a nuisance, quick and early identification and correction of such problems are required by this permit to minimize releases and impacts that could lead to complaints. The monitoring methods and increased frequency is designed for quick identification, response and correction. Following the Complaint Response Program will assure Ash Grove will respond appropriately, including communicating with complainants, and investigating potential causes of the complaints as they may be associated with Ash Grove activities. The recordkeeping and reporting aspects of the Complaint Response Program will document the level of attention the plant devotes to the effort and the appropriateness of their response to complaints.

5. Technical considerations. By following this monitoring frequency, there is an increased chance the causes of emissions (including emissions of clinker dust) that may lead to nuisance complaints will be identified before complaints are registered. Also, following the Complaint Response Program may help identify or isolate a likely source or associate operations such as upset equipment. Observation by plant workers during their normal course of work may also help to suggest potential areas of material release that could cause complaints.

5. Requirement I.A.9, I.A.10, I.A.11, I.A.13 - BACT and Reasonable Precautions Preventing Fugitive Dust

Puget Sound Clean Air Agency Regulation I, Section 9.15(a) (effective date – 8/10/89) is a federally enforceable requirement for employing BACT for fugitive dust.

Puget Sound Clean Air Agency Regulation I, Section 9.15(a) requires best available control technology (BACT) for all fugitive dust emissions. WAC 173-400-040(3) addresses fugitive dust emissions for some activities and WAC 173-400-040(8) requires reasonable precautions or reasonably available control technology (RACT) to control fugitive emissions. Both of these Ecology regulations are federally enforceable (effective date - 9/20/93). Recording of fugitive dust emissions is not necessarily a violation of the requirement, since the requirement does not prohibit fugitive dust emissions, but prohibits fugitive dust unless BACT is employed. BACT is employed for all sources of dust at this plant. Equipment controlled or vented directly through a stack is incapable of violating this standard while complying with the other requirements in the permit.

Puget Sound Clean Air Agency Regulation I, Section 9.15(c) (effective date – 8/10/89) requires fugitive dust not be emitted from general fuel burning equipment, general equipment used in a manufacturing process, or general control equipment.

Puget Sound Clean Air Agency Regulation I, Section 9.15(c) prohibits fugitive dust emissions from any refuse burning equipment, fuel burning equipment, equipment used in a manufacturing process, or control equipment. Fugitive dust emissions are emissions of smoke, dust or fumes that are not collected by a capture system and emitted from a stack. Ash Grove does not have any refuse burning equipment (i.e., equipment employed to burn any solid or liquid combustible refuse), and all other equipment subject to this requirement is either controlled or vented directly through a stack and is addressed by a combination of monitoring requirements.

Therefore, the monitoring methods specified for these requirements are the combination of the weekly Rooftop Inspections (Section II.A.3 of the permit) and the monthly O&M Plan Inspections (Section II.A.4 of the permit). As described above, the weekly rooftop inspections to monitor for fugitive emissions are intended to identify issues as they occur. The monitoring method is based on visual inspections with Ash Grove taking corrective action within 24 hours, if any fugitive dust emissions are noted. The monitoring method is consistent with Puget Sound Clean Air Agency's *"Agency Policy on Fugitive Dust Controls, March 1995,"* which specifies reasonable precautions that must be taken to prevent fugitive dust emissions, but does not necessarily define BACT for all processes. The O&M Plan Inspections are the preventative measure intended to identify operation and maintenance issues which could lead to a fugitive emission condition if they were not addressed appropriately.

The fugitive dust requirements contained in the state implementation plan are addressed in Requirements I.A.9 through I.A.12. The Puget Sound Clean Air Agency Board of Directors revised Section 9.15 on March 11, 1999, and it became effective April 17, 1999. The revised fugitive dust requirements are included in the state-only Requirement I.A.13. The amended version will be forwarded to EPA as a SIP amendment. Upon approval of the SIP changes, the revised version of Regulation I, Section 9.15 will be federally enforceable and the old version will no longer apply. The revised rule requires the use of reasonable precautions for fugitive dust and lists some examples of reasonable precautions. The Monitoring, Maintenance and Recordkeeping Methods are the same as those listed in Requirements I.A.9. through I.A.12.

The Puget Sound Clean Air Agency has determined that the Rooftop Inspections (Section II.B.3) monitoring procedure should be weekly for the reasons listed below.

1. <u>Initial compliance.</u> On a plant-wide basis, Puget Sound Clean Air Agency has identified fugitive dust as a significant potential emission at Ash Grove.

2. <u>Margin of compliance.</u> Because of the significant quantity of dry dusty materials that are handled and processed, there is a significant potential to cause fugitive dust emissions even if Ash Grove follows good housekeeping practices. Although all the roadways and parking lots are paved within the Ash Grove plant boundary and all significant emission points are controlled, the potential remains for the generation of air contaminant emissions. Therefore, the equipment is required to be visually inspected from a rooftop viewing weekly to ensure it is working properly without fugitive emissions.

3. <u>Variability of process and emissions.</u> Although the process has a minimal amount of variability, there is substantial variability in the amount of fine loose dry powdery materials that can potentially be associated with not employing BACT. Spillage and handling of materials are the greatest causes for variability of fugitive dust.

4. <u>Environmental impacts of problems.</u> Although BACT is followed and employed at Ash Grove, there is likely to be some environmental impacts from fugitive dust potentially released to the environment. Weekly inspections will minimize the emissions and potentially discover problems before impacts become significant.

5. <u>Technical considerations.</u> Ash Grove is required to perform self inspections and by following this inspection frequency, following a good O&M Plan (as tracked through

Section II.A.4 of the permit), and by making corrections and modifications in response to the Complaint Response Program as appropriate, Ash Grove will substantially avoid failures of the air pollution generating or controlling systems which are the main causes of fugitive particulate emissions.

6. Requirement I.A.12 - Track-Out and Spillage Emissions

Puget Sound Clean Air Agency Regulation I, Section 9.15(b)(effective date – 8/10/89) requires that Ash Grove prevent vehicles from operating on paved roads open to the public:

1. Unless dirt loads are secured, sand is dropped for traction, or public agencies are constructing or maintaining roads;
2. Unless dirt loads are covered or have enough freeboard to prevent spillage; or
3. Unless its vehicles have no dirt on their body, fenders, frame, undercarriage, wheels, or tires.

Puget Sound Clean Air Agency considers the deposition of dirt onto public paved roadways a violation of Section 9.15(b).

It is Ash Grove's responsibility to monitor facility-wide for securing of dirt loads, dust spillage or dirty undercarriages and to respond to nuisance complaints (see Requirements I.A.6 and I.A.12) of particulate emissions or deposition of particulate associated with track-out or dust spillage. Receiving complaints does not necessarily mean Ash Grove is in violation of this requirement, but triggers action by Ash Grove to prevent violations. Ash Grove has not received any notices of violation of this applicable requirement, nor has it received any complaints.

Puget Sound Clean Air Agency has determined that weekly monitoring is appropriate for track-out and dust spillage prevention for the reasons listed below.

1. <u>Initial compliance.</u> The Puget Sound Clean Air Agency has not issued any notices of violation for dust or track-out violations to Ash Grove during inspections (see Compliance History). However, there is a significant potential to generate track-out materials at Ash Grove if proper O&M is not followed. Therefore, the Puget Sound Clean Air Agency concludes that weekly visual inspections are required to assure continued compliance with the track-out requirements, as described in Section II.A.5 (Vehicle Track Out) of the permit.

2. <u>Margin of compliance.</u> Even though the Agency has not issued any notices of violation to Ash Grove for dust spillage or track-out, Ash Grove processes tons of material that could potentially become a spillage or track-out problem if a good O&M Plan is not followed and so there is not a large margin of compliance. Therefore, the Puget Sound Clean Air concludes that a weekly monitoring frequency is required.

3. <u>Variability of process and emissions.</u> Although the process has a minimal amount of variability, there is substantial variability in the amount of fine loose dry powdery materials that can contribute to spillage or track-out of materials. Spillage and handling of materials are the greatest causes for variability of generation track-out materials.

4. Environmental impacts of problems. If proper O&M is not followed or employed at Ash Grove, there would be significant environmental impacts from fugitive dust that could lead to emissions of air contaminants that are detrimental to persons or property. By following a good O&M Plan, spillage and track-out will be minimized.

5. Technical considerations. Ash Grove is required to perform self inspections. By following a good O&M Plan, and making corrections and modifications to this Plan, Ash Grove will very likely avoid generating spillage or track-out of materials. The monitoring for Vehicle Track Out is a simple procedure with one point to observe – East Marginal Way at the plant entrance. Discussions with plant personnel indicate that this happens every day as a routine part of coming to work. The weekly frequency reflects the required timing to observe and record the observation.

7. Requirement I.A.14 and I.A.15 – Operation and Maintenance Standards

Puget Sound Clean Air Agency Regulation I, Section 9.20 requires Ash Grove to maintain equipment in good working order. Section 9.20(a) applies to sources that received a Notice of Construction Order of Approval under Puget Sound Clean Air Agency Regulation I, Article 6. Section 9.20(b) applies to equipment not subject to Section 9.20(a). Puget Sound Clean Air Agency Regulation I, Section 7.09(b) requires that Ash Grove develop and implement an O&M plan to assure continuous compliance with Puget Sound Clean Air Agency Regulations I, II, and III. Section 7.09(b) also requires Ash Grove to promptly correct any defective equipment. However, the underlying requirement in most instances does not define "promptly," hence for significant emission units and applicable requirements that Ash Grove has a reasonable possibility of violating or that a violation would cause an air quality problem, the Puget Sound Clean Air Agency added clarification that "promptly" usually means within 24 hours. For many insignificant emission units and for equipment not listed in the permit, "promptly" cannot be defined, because the emission sources and suitable pollution control techniques vary widely, depending on the contaminant sources and the pollution control technology employed. However, the permit identifies a means by which to identify if Ash Grove is following good industrial practice.

This requirement specifies that the Plan shall reflect good industrial practice, but does not define how to determine good industrial practice. In the past, the Puget Sound Clean Air Agency has found that, in most instances, following the manufacturer's operations manual or equipment operational schedule, minimizing emissions until repairs can be completed and taking measures to prevent recurrence of the problem may be considered good industrial practice. This language is consistent with a Washington Department of Ecology requirement in WAC 173-400-101(4). The Puget Sound Clean Air Agency also believes that other criteria included in the permit represent credible evidence towards these requirements. For example, monitoring results, opacity observations, or fugitive dust problems may also reveal that O&M plan provisions had not been followed between the scheduled O&M plan inspections. This is consistent with the Washington State court decision, Longview Fibre Co. v. DOE, 89 Wn. App. 627 (1998), which held that similar wording was not vague and gave sufficient notice of prohibited conduct. In such a circumstance, Ash Grove may have to report deviations under these requirements based on information collected beyond this monitoring procedure.

Section II.A.4 of the permit (O&M Plan Inspections) identifies a monthly facility wide inspection to verify the O&M plans developed by Ash Grove are being followed and identify when the plan needs improvements or updates based on the observations. The inspection procedure requires Ash Grove to look for prohibited activities, activities that required prior approval, evidence of proper operation of equipment, evidence of fugitive dust controls are effectively being used, and odorous emissions. All of these are intended to be preventative inspection activities which should identify potential problems before they trigger required responses under other parts of the permit.

Puget Sound Clean Air Agency has determined that monthly monitoring is appropriate for O&M plan inspections for the reasons listed below.

1. Initial compliance. The Puget Sound Clean Air Agency has issued a limited number of notices of violation good working order problems, but none in the last few years. This type of violation is often associated with another problem and the O&M or good working order status is considered a contributing factor to the problem. For the older compliance history at Ash Grove, this was the case. Therefore, the Puget Sound Clean Air Agency concludes that monthly O&M Plan inspections are required to assure continued compliance with both of these O&M based standards.

2. Margin of compliance. Even though the Agency has not issued any recent notices of violation to Ash Grove for the good working order provisions, Ash Grove's recent history of nuisance violations from fallout suggests that operations and maintenance practices may have been a factor in the compliance challenge. The lack of O&M type violations in those recent incidents is likely due to a lack of a direct "cause and effect" linkage at the time the violation was documented. However, it does suggest that there is not a large margin of compliance with these requirements, but a failure in this area of the permit will most likely lead to real impacts and possible violations of emission or impact based standards. Therefore, the Puget Sound Clean Air concludes that a monthly monitoring frequency is required.

3. Variability of process and emissions. Although the process has a minimal amount of variability, there is substantial amount of equipment actively operational at the plant a large amount of material being handled.

4. Environmental impacts of problems. If proper O&M is not employed at Ash Grove, there would be significant environmental impacts from fugitive dust that could lead to emissions of air contaminants that are detrimental to persons or property. By using and updating a good O&M Plan, other permit deviations and possible violations can be minimized.

5. Technical considerations. Ash Grove is required to perform self inspections. By following a good O&M Plan, and making corrections and modifications to this Plan, Ash Grove will very likely avoid other permit deviations and possible violations. The monthly facility wide inspections identified in the permit (Section II.A.4) are broad ranging and are not limited to equipment procedures alone. These facility wide inspections are to include general observations which may trigger responses that include, but are not limited to new O&M plan development, permit deviation reports, or other

action to respond to observations of activities which may either be noncompliant or lead to noncompliance if unattended. The monthly frequency reflects the required timing to observe and record the observation.

8. Requirement I.A.16 - Emissions from a common stack

WAC 173-400-040 (8/20/93) requires that the emissions from a common stack must meet the most restrictive standard of any of the connected emissions units.

Ash Grove does not have stacks that are subject to this standard, so no monitoring is required.

9. Requirement I.A.17 - HCl Emissions

Puget Sound Clean Air Agency Regulation I, Section 9.10(a) (effective date – 6/9/88) specifies that HCl emissions shall not exceed 100 ppm (dry), corrected to 7% O_2 for combustion sources. The kiln is the only known source of HCl at Ash Grove. The kiln is subject to the emission limits and testing of 40 CFR 63, Subpart LLL. The NESHAPS applicability testing of the main stack demonstrated the HCl concentration is less than 5 ppm. If operations changed at the kiln which could increase the observed HCl concentrations or emission rates, Ash Grove will face the major source threshold trigger for additional NESHAP affected unit coverage well before the HCl limit of 100 ppm is ever reached. Therefore, there is no requirement for monitoring other that required by the NESHAPS.

Section I.B. (Emission Unit Applicable Requirements)

Section I.B. of the permit lists applicable requirements that are specific to an emission unit or activity. The Generally Applicable Requirements of Section I.A. apply to all the emission units listed in Section I.B. and are not repeated in this section. Monitoring Methods and Reference Methods are also identified if they are different from, or in addition to, those listed in Section I.A.

The EPA incorporates what the EPA has determined to be “all necessary monitoring” into all recently adopted federal air pollution regulations. Where a recently adopted federal regulation does not identify a monitoring method, the permit does not identify one either, except in some cases where the Puget Sound Clean Air Agency has determined additional monitoring to be necessary. Finally, any requirements that are inapplicable to the specific emission unit are also listed in this section.

All generally applicable requirements apply to the specific emission units. To simplify the permit, the Puget Sound Clean Air Agency did not repeat these requirements for each unit unless a specific monitoring requirement applied. Following is a summary of all the Notice of Construction Applications and the Orders of Approval issued by the Puget Sound Clean Air Agency. The applicable portions of these Orders of Approvals are listed in Section I.B. for the specific applicable requirements for each emission unit. The table below contains a list of all the obsolete Orders of Approval issued to Ash Grove.

1. Requirements: EU 1.1 through EU 1.4 for Kiln Baghouse Visible Emissions

Requirement EU 1.1, which cites Puget Sound Clean Air Agency Regulation I, Section 9.09(b)(1) (effective date 2/10/94), is a 20% opacity limit for a period aggregating more than 3 minutes in any one hour (as determined by the continuous emission monitoring system) applies to the Kiln.

Requirement EU 1.2, which cites Puget Sound Clean Air Agency Regulation I, Section 9.04(c)(2) (effective date 4/09/98), is both a visual and an instrumental opacity standard. This standard is a 20% opacity limit. The source shall not cause or allow the emission of any air contaminant during any hour that contains any consecutive 6-minute period averaging greater than 20% opacity from the Kiln.

EU 1.1 will be superceded by EU 1.2 when EPA adopts the current SIP. The reference methods include both EPA Method 9 (40 CFR 60, Appendix A (7/1/02) (Appendix X.A.(2) of this permit) and EPA Performance Specification 1, (40 CFR 60, Appendix B (7/2/97) (Appendix X.C.(1) of this permit).

Requirement EU 1.3, which cites Puget Sound Clean Air Agency Regulation I, Section 9.09(b)(2) (effective date - 2/10/94), is a 5% CEMS opacity limit averaged for one hour applies to the Kiln.

Requirement EU 1.4, which cites Puget Sound Clean Air Agency Regulation I, Section 9.04(c)(1) (effective date 4/9/98), is a 5% opacity limit as a one-hour average applies to the Kiln.

EU 1.3 will be superceded by EU 1.4 when EPA adopts the current SIP. Note that EU 1.2 visible emission standard has two compliance reference methods. The results of the two compliance reference methods may not be identical because the opacity measurements are conducted at difference locations. The CEMS measures the opacity inside the stack (the transmissometer operates at all times the Kiln operates) where the temperature is hot. EPA Method 9 measures the opacity from outside the stack where the cooler temperature allows particulate in the form of mist or vapor to condense that otherwise may not be detected by the CEMS inside the hot stack.

Regulation I, Section 9.03(a)(1) (effective date 9/08/94) does not apply to the kiln emissions because Regulation I, Section 9.03(e) (effective date 9/08/94) states, "Section 9.03(a) shall not apply to any source which meets the requirements of Section 9.09(c)." Ash Grove meets the requirements of Regulation I, Section 9.09(c) (effective date 2/10/94), so 9.03(a)(1) (effective date 9/08/94) does not apply.

The old version of Regulation I, Section 9.03(a)(1) (effective date 9/08/94) will be superseded by the new version of Regulation I, Section 9.03 (effective date 3/11/99) and the new version of Regulation I, Section 9.04 (effective date 4/9/98), once they are adopted into the SIP. When this happens the SIP will list both compliance methods for this standard.

This continuous opacity monitoring allows Ash Grove to take timely corrective action in response to increasing CEMS measured emissions. These requirements are continuously monitored for compliance with the opacity standards and deviations from the standards are enforceable by Puget Sound Clean Air Agency. This Agency reviews the monthly monitoring reports as a part of the enforcement assessment for Ash Grove.

2. Requirements EU 1.5 (NC 5687 Waste Derived Fuels) and EU 1.7 and 1.8 (NC 5755 Tire Derived Fuel)

Ash Grove has two Orders of Approval which allow replacement or alternative fuels to be used in the kiln. Order of Approval No. 5687 (1/11/95) allows waste derived fuel to be fired in the Kiln and includes a limitation on the amount which can be burned. Order of Approval No. 5755 (11/4/93) allows burning whole tires in the Kiln and limits the weight of tires burned.

The monitoring requirements to demonstrate compliance with these fuel restrictions is for Ash Grove to maintain records on site of the fuels burned. The recordkeeping is for daily and annual amounts and types of fuels with the average daily amount of tires burned as specified in Conditions No. 6 in both Orders of Approval.

The Puget Sound Clean Air Agency has determined that this monitoring and recordkeeping frequency is satisfactory to assure compliance with the Order of Approval limits for the following reasons.

1. Initial compliance. Ash Grove has demonstrated compliance with the conditions and limits of the above Orders of Approval and maintains equipment associated with the handling of these fuels. Ash Grove has done extensive testing to show regulatory compliance.
2. Margin of compliance. The limits of waste fuels and tires are easy to manage because this cement plant does not generate, use or burn a significant amount of these fuels. The margin for compliance is considered to be large for these conditions.
3. Variability of process and emissions. Because the manufacturing process is relatively constant, it is unlikely that the variability of the process itself will cause violations of these limits.
4. Environmental impacts of problems. The air modeling of the stack emission while burning these fuels has shown that there are no significant environmental issues.
5. Technical considerations. The Kiln has a significant flow rate so the emission limits are continuously monitored. By following the required monthly recordkeeping and monitoring schedule any significant emissions will be detected and corrected before there are compliance problems.

3. Requirements EU 1.9 through 1.14 Kiln Emission Limits for NOx, CO, SO2 and PM10 (Order of Approval No. 7381 and PSD Permit 90-03)

Puget Sound Clean Air Agency Order of Approval No. 7381 (6/6/01) and Ecology's PSD Permit 90-03 limit the main stack baghouse emissions for NOx, CO, SO2 and PM. These current versions of approvals represent the third version of conditions, with the original versions approved in 1990. As Ash Grove gained experience with their kiln following the project modifications, various conditions in the approvals needed modified as some portions of the limitations were not achievable. What conditions are in effect at this time are the following forms of limitations:

- Concentration limitations on NOx, CO, and SO2 with different averaging times
- Startup operational procedures (attached to the Order of Approval as approved startup and shutdown procedures for SO2 compliance and identified in Section II.B.8 of the permit) and startup emission limits which apply to SO2 emissions
- Annual mass emission rate limitations for NOx, CO, SO2, and PM-10, to include startup and shutdown operations
- Mass emission rate limit for CO on an 8-hour average basis and a PM-10 mass emission limit in terms of lb/hr

Ash Grove uses a continuous emission monitoring system and the submittal of monthly reports to satisfy the monitoring requirements for this order of approval and the PSD permit approval. These reports have been submitted routinely in the past and will continue under this operating permit. Some new monitoring provisions are being added to these ongoing practices as a part of this operating permit to demonstrate compliance with all of these requirements.

In Section II.B.9 of the permit, a PM source test is identified to be completed once during each permit term. The purpose of this test is to revalidate PM emission limit compliance and re-establish the emission rate to production rate relationship. This relationship is used to convert annual production rates to mass emission rates identified in the identified approvals orders. Additionally, the production rate data required for other purposes (Section II.B.10 of the permit) will support these annual emission calculations.

In Section II.B.3 of the permit, a requirement to calculate and record the mass emission rates for the gaseous pollutants has been included. The CEMS data demonstrates compliance with the concentration based limits, but does not directly produce mass emission rate values. Most of the mass emission rate limits are on an annual basis (CO being the exception) and no direct requirement exists in the existing Orders to make that compliance determination. This mass conversion rate will provide the positive record that the mass emission rate limits are met and that those values include all operations, including startup and shutdown.

The Puget Sound Clean Air Agency has determined that the monitoring, recordkeeping and reporting frequency for these combined Order of Approval and PSD Permit conditions is satisfactory to assure compliance for the following reasons:

1. Initial compliance. Ash Grove has demonstrated compliance with these conditions and the current limitations in these approvals match the operational capabilities of the kiln. Past violations have been noted against prior versions of the approvals, but no violations of these present limitations have been noted. Past source testing for PM emissions have also indicated compliance with the underlying PM-10 limitations.

2. Margin of compliance. The margin of compliance is small for the concentration based limits. The revisions to Orders of approval over the past 10 years have reflected

challenges with the original concentration limits, but the current form of limitation does not produce the same, historical amount of violations. The current revised version of the Order of Approval identifies specific startup and shutdown procedures that are followed instead of defined concentrations monitored by the CEMS. This is an indication that the compliance margin is small and must be actively managed by the source and guided by the CEMS data at other routine operation times. The margin of compliance for the annual mass emission rates is considered high. There are no monitoring, recordkeeping, or reporting requirements for those mass emission rates in the approval orders. The margin of compliance for PM-10 emissions is also considered high, since the kiln is monitored by a COMS to verify compliance with a visible emission limitation of 5% opacity.

3. Variability of process and emissions. The process is highly variable during startup and shutdown procedures and relatively constant during normal operations. This fact is reflected by the startup and shutdown procedures being defined as an approval order condition and the normal operations being monitored by the CEMS.

4. Environmental impacts of problems. The air modeling of the stack emissions during the Notice of Construction and PSD permit review has shown that there are no significant environmental issues related the impacts of these pollutants.

5. Technical considerations. The Kiln has a significant flow rate so the emission limits are continuously monitored. By following the required monthly recordkeeping and monitoring schedule any significant emissions will be detected and corrected before there are compliance problems.

4. Requirements EU 1.15 through 1.17 and EU-3 – Portland Cement NSPS (40 CFR 60, Subpart F)

What NSPS Subpart F Requirements Apply to Ash Grove?

Ash Grove is subject to the Portland Cement NSPS regulation promulgated in 40 CFR 60, Subpart F. As a result, corresponding applicable provisions of the NSPS General Provisions (40 CFR 60, Subpart A) are also applicable to Ash Grove.

Ash Grove has demonstrated compliance with the opacity and particulate requirements of the NSPS for the affected emission units. A performance test report for the kiln was submitted to this Agency on September 7, 1993 and it demonstrated compliance with the Subpart F provisions which apply to the kiln.

This NSPS regulation was triggered by the kiln project originally approved in 1990. The emission units at the plant with this standard as an applicable requirement include the kiln and raw mill, as well as other various emission units identified in EU-3 of the permit. The clinker storage shed, the finish mills, the steel scale tanks and the Group II silos included in the permit are not subject to this NSPS because these units were not constructed or modified after August 17, 1971.

These NSPS requirements are separated in the permit to reflect different standards and different monitoring requirements. In EU 1.15 to EU 1.17, the particulate emission limit and visible emission limit for the kiln are identified, as well as the requirement to record production rates and feed rates. Compliance with the particulate emission limit in this NSPS was demonstrated by the performance test results submitted to this Agency on September 7, 1993. That test report also indicated that the kiln met the visible emission limitation of 10% opacity. While that was compliant, subsequent guidance from the EPA indicates that the appropriate visible emission limitation for this unit is 20% opacity. In 40 CFR 60.62(a)(2), the visible emission limitation for kiln emissions is identified at 20% opacity. In 40 CFR 60.62(c), the visible emission limitation for other affected facilities is 10% opacity. The raw mill system is considered an "other affected facility" and that seems to have been the observation by Ash Grove with the September 7, 1993 test submittal. In an EPA memorandum from John Rasnic to EPA Regional Air Directors (September 7, 1996, ADI Control Number 9600083), it was concluded that in-line raw mills were considered integral to the operation of the kiln, that such a configuration was not circumvention, and the 20% opacity limitation for the kiln applied to the exhaust for this type of source (see Attachment B). Ash Grove has an in-line raw mill.

The NSPS Subpart F requirements identified in EU-3 (Portland Cement NSPS Affected Facilities) represent all other Subpart F emission units. These units are various point sources and material handling process which are subject to the visible emission limitation of 10% opacity identified in 40 CFR 60.62(c).

How will Ash Grove comply with NSPS Subpart F?

The portions of this subpart which apply to Ash Grove include:

1. Recurring source test for particulate emission compliance demonstration (once each permit term) as described in Section II.B.9 of the permit;
2. Continuous opacity monitoring of the Kiln Baghouse for opacity in Section II.B.1 of the permit;
3. Routine opacity monitoring identified in Section II.A.1 of the permit, which monitors the baghouse emissions to no visible emissions (for units other than the kiln;
4. Semi-Annual Compliance Reports (to include Excess Emission Reports) in Section II.C.5 of the permit;
5. The Startup, Shutdown, and Malfunction (SSM) plan meeting requirements of Subpart A

The specific requirements from the NSPS Subpart F provisions which are applicable are included in the operating permit. The NSPS Subpart A General Provisions which are applicable to Ash Grove and which may govern action or future potential action on the part of Ash Grove (under this operating permit and implementation of Subpart F compliance) have been included for reference. The underlying requirements are in Subpart F, which identify the Subpart A citations associated with compliance activities.

5. Requirements EU 1.18 through 1.20 – Coal Preparation Facilities NSPS (40 CFR 60, Subpart Y)

What NSPS Subpart Y Requirements Apply to Ash Grove?

Ash Grove's coal mills are subject to the Coal Preparation Facilities NSPS regulation promulgated in 40 CFR 60, Subpart Y. As a result, corresponding applicable provisions of the NSPS General Provisions (40 CFR 60, Subpart A) are also applicable to Ash Grove.

This requirement was discovered during the preparation of this operating permit to be applicable to the coal mill exhaust. It appears this NSPS regulation may have also been triggered by the kiln project in 1990 and Subpart Y applies because the coal mills have the ability to process more than 200 tons/day. No NSPS performance test of this emission unit has been completed for these Subpart Y objectives.

The emission units at the plant with this standard as an applicable requirement are the two coal mill baghouses, which exhaust a portion of the kiln exhaust gas used to dry coal prior to its use in the kiln as fuel. The applicability of this rule needed some clarification by the EPA since the use of the exhaust gas stream from the kiln could lead to the conclusion that the NSPS, Subpart F for Portland cement manufacturing applied to these discharge point. In an EPA memorandum from John Rasnic to the Air Compliance Branch for New Jersey/Caribbean Compliance Section (May 12, 1995, ADI Control Number 9600082), it was directly concluded that when gases originating in one affected facility (e.g. cement kiln and Subpart F) and pass through another affected facility (e.g. coal mill dryer and Subpart Y), the EPA applies to the standard for the affected facility from which the gases are directly discharged to the atmosphere (see Attachment C). This cited memorandum specifically talks about Subpart F and Subpart Y overlaps and identifies the coal mill dryer as being subject to Subpart Y.

Subpart Y also regulates coal storage, transfer and loading equipment between the raw coal silo and the kiln. The Subpart Y requirements for this equipment are listed in Section I.B.2 of the permit. The coal loading, transfer and storage equipment upstream of the raw coal silo are not affected emission units subject to Subpart Y. In EPA clarifications (February 24, 1977, ADI Control Number Y002 and October 29, 1990, ADI Control Number NR90), the EPA indicates that unless the equipment is handling coal transfer to or from an affected unit (see Attachment D), it would not be subject to the rule. These identified units fit this definition and are not subject to Subpart Y.

In EU 1.18 to EU 1.20, the particulate emission limit and visible emission limit for the coal mill dryer exhaust gases are identified, as well as the requirement to monitor the coal mill exhaust gas temperature. Compliance with the particulate emission limit and the visible emission limit will be established by a performance test included in the operating permit (see Section II.B.12 of the permit) and the temperature monitoring requirement overlaps with a NESHAP requirement to monitor temperature (see Section II.B.13 of the permit).

The NSPS Subpart Y requirements identified in EU-2 (Coal Processing, Storage and Transfer Facilities) represent all other Subpart Y emission units. These units are various point sources and material handling processes which are subject to the visible emission limitation of 20% opacity identified in 40 CFR 60.252(c).

How will Ash Grove comply with NSPS Subpart Y?

The portions of this subpart which apply to Ash Grove include:

1. Performance source test for particulate emission and visible emission compliance demonstration as described in Section II.B.12 of the permit;
2. Routine opacity monitoring identified in Section II.A.1 of the permit, which monitors the baghouse emissions to no visible emissions;
3. Semi-Annual Compliance Reports (to include Excess Emission Reports) in Section II.C.5 of the permit;

4. The Startup, Shutdown, and Malfunction (SSM) plan meeting requirements of Subpart A

The specific requirements from the NSPS Subpart Y provisions which are applicable are included in the operating permit. The NSPS Subpart A General Provisions which are applicable to Ash Grove and which may govern action or future potential action on the part of Ash Grove (under this operating permit and implementation of Subpart Y compliance) have been included for reference. The underlying requirements are in Subpart F, which identify the Subpart A citations associated with compliance activities.

6. Requirements EU 1.21 through 1.35– Portland Cement NESHAPS (40 CFR 63, Subpart LLL)

What NESHAP Subpart LLL Requirements Apply to Ash Grove?

Ash Grove is subject to the Portland Cement NESHAP regulation promulgated in 40 CFR 63, Subpart LLL. As a result, corresponding applicable provisions of the NESHAP General Provisions (40 CFR 63, Subpart A) are also applicable to Ash Grove.

Ash Grove is classified as a major source of criteria pollutants and thus was required to obtain an operating permit. However, the plant is considered an area source for hazardous air pollutants (HAPs), meaning the source's potential to emit is less than 10 tons/year for any individual HAP and less than 25 tons/year for total HAPs. The industry and EPA guidance makes it clear that emissions of hydrogen chloride and formaldehyde are the key HAPs for this evaluation.

Ash Grove's emission rate for HCl was found to be 1.26 tons per year and formaldehyde was found to be 8.58 tons per year as a maximum potential to emit.

Ash Grove completed area source determination testing in May 2001. Testing to demonstrate compliance with this standard and to set the limits of Kiln baghouse inlet temperatures for several operational modes (raw mill online and raw mill offline) and for the coal mill exhaust was completed during October 22-24, 2002. The results of that performance testing were submitted to the Puget Sound Clean Air Agency by the deadlines outlined in the NESHAP. The May 1, 2001 test report was received by this Agency on July 2, 2001 and it demonstrates that Ash Grove is an existing area source with HAPs projected to be less than 10 tons/year.

The area source definition means that the only emission limit from this regulation which applies to this plant is a dioxin/furan (D/F) limit of 0.40 ng/dscm (TEQ) at 7% O2 when the average Kiln baghouse inlet temperatures are equal to or less than 400ºF during the performance test [40 CFR 63.1343(d)(2)] and 0.20 ng/dscm (TEQ) at 7% O2 when the average Kiln baghouse inlet temperatures are less than 400ºF during the performance test [40 CFR 63.1343(d)(1)]. Ash Grove has conducted D/F performance testing for setting the Kiln inlet baghouse temperature for the two modes of operation of the Raw Mill (<u>ON</u> and <u>OFF</u>).

This testing included the Coal Mill Grinder emissions of dioxin/furan. Although most of the Kiln emissions vent through the Raw Mill (when it is operating) and exhaust out the main stack, there is a small portion of hot Kiln exhaust gases that are routed directly from the Kiln exhaust (before the Kiln gases enters the Raw Mill or main baghouse). This small portion of hot Kiln gas vents through the Coal Mill Grinder baghouse. This Coal Mill Grinder uses hot kiln exhaust gases for drying processed coal for Kiln fuel. The Kiln exhaust is withdrawn at the bottom of the precalciner tower and before the Raw Mill. For safety reasons the Coal Mill temperature must not be allowed to exceed about 180ºF to 200ºF. Although, the dioxin emission limit of 40 CFR §63.1343(d)(3) limits all Kiln exhaust discharge points that the Kiln exhausts to the atmosphere, Ash Grove requested an alternative monitoring method for the coal mill baghouse temperature requirement as a method of dealing with the safety challenges created by testing the coal mill at maximum temperature conditions. In a letter from the Puget Sound Clean Air Agency on October 18, 2002, the proposed intermediate monitoring change was approved. This intermediate alternative monitoring change required the performance test to be completed for the coal mill exhaust gas but established the temperature value that shall not be exceeded during operation at 200ºF (see Attachment E). It is expected that Ash Grove will demonstrate the dioxin/furan emissions are well below the emission standards of the NESHAPS once the performance test and compliance demonstration is submitted. The dioxin/furan performance test must be repeated every 30 months. As a result, the actual value of the temperature limitation is not being included as an explicit operating permit condition at this time since it will routinely be updated with the subsequent performance test requirements. It is important to note that this NESHAP regulation states (40 CFR 63.1350(b)) that, "Failure to comply with any provision of the operations and maintenance plan developed in accordance with 40 CFR 63.1350(a) shall be a violation of the standard." It is also important to note that this regulation indicates that temperature observations greater than the test derived value for that operational condition is also considered an exceedances of the dioxin/furan limit.

How will Ash Grove comply with NESHAP Subpart LLL?

The portions of this subpart which apply to Ash Grove include:

1. Applicability determination for area/major source
2. Performance test for compliance demonstration
3. Continuous Kiln inlet baghouse temperature monitoring and continuous coal mill baghouse temperature monitoring
4. Submit an O&M plan (for review and approval) which meets the requirements identified in this regulation
5. Develop & implement a Startup, Shutdown, and Malfunction (SSM) plan meeting the requirements of Subpart A and Subpart LLL
6. Document, report, and update SSM plan activities, as necessary and as identified in Subpart A
7. Repeat the dioxin/furan performance testing once every 30 months.

The specific requirements from the NESHAP Subpart LLL provisions which are applicable are included in the operating permit. The NESHAP Subpart A General Provisions which are applicable to Ash Grove and which may govern action or future potential action on the part of Ash Grove (under this operating permit and implementation of Subpart LLL compliance) have been included for reference, as appropriate. The underlying requirements are in Subpart LLL, which identify the Subpart A citations associated with compliance activities.

7. Requirements EU 1.36 through 1.46 - WAC 173-434 Solid Waste Incinerator Facilities

Puget Sound Clean Air Agency concluded during the review of the comments on the draft operating permit that this regulation did apply to Ash Grove and had been omitted from the original document. The details of this applicability and impacts of the recent Ecology revision of this regulation are discussed in detail in the response to comments below [see Comment 28 (by Ash Grove 4/30/03)].

WAC 173-434 initially was adopted on September 17, 1990, with an effective date of October 18, 1990. The Department of Ecology amended WAC 173-434 on December 22, 2003. Ash Grove currently is not subject to the 2003 version of WAC 173-434, because the 2003 version exempts tires and non-hazardous waste oil burned in a cement kiln from the definition of "solid waste," and Ash Grove currently is not permitted to burn any other materials for energy recovery that are classified as "solid waste" under the 2003 version of the incinerator regulation. Ash Grove remains subject to the 1990 version of 173-434, because Ash Grove burns more than 12 tons per day of whole tires, and the 1990 version does not exempt tires. Under both the 1990 and the 2003 versions of WAC 173-434 the definition of "solid waste" does not include industrial byproducts consumed as raw materials. For instance, Ash Grove consumes bottom ash from the Centralia coal plant as a source of alumina, slag from the Trail smelter as a source of iron, and gypsum chips from a drywall plant as a source of silica. These materials are not classified as "solid waste," and their use does not subject Ash Grove to the requirements of WAC 173-434.

The applicable requirements of the 1990 version of this regulation have been added to the permit in Conditions EU 1.36 through 1.46, to include some specific monitoring, recordkeeping, and reporting provisions associated with this applicable regulation.

The requirements from this regulation are clear and discrete, with a couple of exceptions. In Condition EU 1.41 (3% oxygen concentration in gas leaving the kiln) and EU 1.44 (350ºF inlet temperature to the kiln baghouse), the regulations for these operational limitations do not identify averaging times for the monitoring or compliance demonstrations. In both of these requirements, this Agency has concluded that the appropriate averaging period is 24-hours on a block average basis. Some of the other regulatory requirements of this rule specify averaging times (e.g. EU 1.37 and EU 1.39). When an averaging time is not specified in the regulation and a monitoring requirement for compliance creates the need to specify the averaging time, this Agency has to establish one for the permit. In this circumstance, this Agency has concluded that the 24-hour average is consistent with the regulation since the applicability criteria for the rule is the burning of 12 or more tons of solid waste per day.

This agency has determined that the WAC 173-434-130 emission limits for particulates and hydrogen chloride (HCl) do not apply to Ash Grove, because WAC 173-434-100(2) exempts incinerator facilities from the requirements of WAC 173-434 where other, more stringent regulations, controls or emission limits apply. Ash Grove's kiln is subject to a particulate limit (see Condition EU 1.13) more stringent than that imposed by WAC 173-434-130(1). Ash Grove's designation as an area source under 40 CFR Part 63, Subpart LLL requires Ash Grove to emit HCl at rates well below the 50 ppm limit contained in WAC 173-434-110(2). The Inapplicable Requirements table in Section VIII of the permit grants the protection of the Title V permit shield to these findings.

8. Requirements EU-4.1 and 4.2 Finish Mills (Order of Approval No. 5276)

Puget Sound Clean Air Agency Order of Approval No. 5276 (1/19/94) identifies the particulate concentration limitation of 0.01 gr/dscf (Order of Approval 5276, Condition No. 4) and a visible emission limitation of 10% opacity (Order of Approval 5276, Condition No. 5). These emission limitations were identified to specify the emission control performance requirements for the baghouses installed on these units. The specific monitoring requirements identified in Condition No. 7 of that Order has been included as a specific monitoring requirement in Section II.B.4 of the permit. The frequency for this pressure drop is being established with this permit and is identified to be monthly for this unit. That Order originated monitoring requirement is based on pressure drop monitoring and corrective action when the observed pressure drop across the baghouse is outside of the approve range. This specific monitoring is in addition to the general opacity monitoring provisions included in Section I.A.1 of the permit.

9. Requirement EU-5.1 Cement Dome & Steel Scale Tanks (Order of Approval No. 7242)

Puget Sound Clean Air Agency Order of Approval No. 7242 (1/6/98) approved the installation of the cement storage dome controlled by a baghouse. Additionally, the Order approved replacement of a baghouse on the Steel Scale Tanks. The approval order includes requirements to install pressure drop monitoring devices on each baghouse, mark the acceptable range for each baghouse, monitor and record the values for each shift the baghouse is used, and take corrective action if the observation is outside the acceptable range in accordance with the O&M plan (Conditions No. 4-6). These are included in the permit in Section II.B.7. The frequency for this monitoring is specified in the approval order. Additionally, this approval order includes the PM-10 concentration limit of 0.005 gr/dscf (Condition No. 7 of the approval order), which parallels the PM-10 limitations identified and discussed for Condition I.A.5 of this permit. The same monitoring has been included for these emission units (Section II.A.1 General Opacity Monitoring) to demonstrate compliance with this concentration limitation.

10. Requirement EU-6.1 Bulk Loading Station (Order of Approval No. 8318)

Puget Sound Clean Air Agency Order of Approval No. 8318 (1/8/01) approved the installation of a bulk loading station equipped with a baghouse for emission control. The Order of Approval included requirements for no visible emissions or fallout from the baghouse (Condition No. 3) and the observation of visible emissions, abnormal pressure drop, or fallout trigger a corrective action response within 24-hours of observation. The monitoring for these two requirements is identified in Section II.B.11 of the operating permit, which specifies weekly inspections (when the equipment is operating) for visible emissions, pressure drop, and fallout. This monitoring procedure and frequency is specified in the Order of Approval (Condition Nos. 4-6).

11. Requirement EU-7.1 Clinker Storage Shed (Order of Approval No. 8600) and Requirement EU-8.1 Group II Cement Silos (Order of Approval No. 8643)

Both of these approval orders were for the installation of baghouse equipment for particulate matter emission controls. Both orders included the PM-10 concentration limit of 0.005 gr/dscf (Condition No. 3 of each order), which parallels the PM-10 limitations identified and discussed for Condition I.A.5 of this permit. The same monitoring has been included for these emission units (Section II.A.1 General Opacity Monitoring) to demonstrate compliance with this concentration limitation.

Monitoring, Maintenance and Recordkeeping Procedures

Ash Grove must follow the procedures contained in Section II of the permit, Monitoring, Maintenance and Recordkeeping Procedures. Failure to follow a requirement in Section II may not necessarily be a violation of the underlying applicable emission standard in Section I. However, not following a requirement of Section II is a violation of Section II, and Ash Grove must report such violations, as well as violations or deviations from any other permit condition, as a deviation under Section II.C.2 of the permit. In addition, all information collected as a result of implementing Section II can be used as credible evidence under Section V.O of the permit. Reporting a permit deviation and taking corrective action does not relieve Ash Grove from its obligation to comply with the underlying applicable requirement.

A standard Puget Sound Clean Air Agency Notice of Construction (NOC) Approval Condition No. 1, requires that the equipment, device or process be installed according to plans and specifications submitted to the Puget Sound Clean Air Agency. Once the equipment is installed, the Puget Sound Clean Air Agency requires certification by the applicant that the installation was as approved; this is usually done with a Notice of Completion. Normally within six months to a year after receiving a Notice of Completion, a Puget Sound Clean Air Agency inspector verifies by inspection that the equipment was installed as specified and in accordance with the Approval Order. While the Notice of Completion is a one-time requirement that has been completed by Ash Grove, Ash Grove cannot change the approved equipment in such a manner that requires an NOC without first obtaining an NOC approval which is addressed in Section IV.A of the permit. In most cases, once Ash Grove has filed the Notice of Completion and a Puget Sound Clean Air Agency inspector has verified that the equipment was installed according to the Approval Order, the Puget Sound Clean Air Agency considers NOC Condition No. 1 an obsolete condition. However, in some cases in the permit the Puget Sound Clean Air Agency has identified a need to specify that the equipment cannot be altered in such a manner that requires an NOC Approval.

The permit requires Ash Grove to conduct monthly facility-wide inspections as a part of the O&M Plan Inspections. These inspections are to include checking for prohibited activities under Section III of the permit and activities that require additional approval under Section IV of the permit, as well as checking for any “nuisance” odor-bearing contaminants. The Puget Sound Clean Air Agency determined the frequency of these inspections after considering the potential for emissions, the lack of federally required monitoring, Ash Grove's in-house training practices and similar factors. If problems are identified, Ash Grove has the responsibility to not only correct the specific problem, but also to adjust the work practices and training to prevent future problems.

In determining the appropriate monitoring frequencies for monitoring identified in Section II.A. of the permit, the Puget Sound Clean Air Agency considered several factors, including the following:

- Ash Grove’s compliance history and the likelihood of violating the applicable requirement.
- The complexity of the emission unit including the variability of emissions over time.
- The likelihood that the monitoring would detect a compliance problem.

- The likely environmental impacts of a deviation.
- Whether add-on controls are necessary for the unit to meet the emission limit.
- Other measures that Ash Grove may have in place to identify problems.
- The type of monitoring, process, maintenance, or control equipment data already available for the emissions unit.
- The technical and economic considerations associated with the range of possible monitoring methods.
- The type of monitoring found on similar emissions units.

Section II.B of the permit imposes source-specific monitoring methods for particular emission units and applicable requirements. Condition II.B.15, Operational Monitoring For Solid Waste Incinerator Facilities, requires Ash Grove to monitor certain parameters to show compliance with the Design and Operation Standards of WAC 173-434-160. WAC 173-434-160(2) requires incinerator facilities to maintain a minimum combustion chamber residence time of at least one second. The combustion zone of Ash Grove's kiln is the distance from the kiln inlet to the tip of the burner pipe. This distance is 205 feet. Throughout this zone the gas temperature exceeds 1800 degrees F during normal operations. To traverse the combustion zone within one second gas would have to travel 205 feet/second, or 12,300 feet per minute. The working internal diameter of the kiln is 13.5 feet, or an area of 143.1 square feet. The product of the area (143.1 square feet) times the flow rate (205 ft/second) yields the maximum flow rate (1,760,130 actual cubic feet per minute or acfm) at which gas can traverse the kiln before the residence time drops below one second. Condition II.B.15 requires Ash Grove to monitor flow rate at the baghouse outlet to demonstrate that the residence time and combustion air distribution control requirements are met.

WAC 173-434-130(3) requires that excess air leaving the final combustion zone must contain at least three percent oxygen measured on a wet basis. Ash Grove's oxygen analyzer, located at the outlet of the preheat tower, measures kiln exhaust gas oxygen content on a "dry" basis. The moisture content of the exhaust gas stream from the Ash Grove's process averages 10%. To convert "dry" oxygen content data to show compliance with the "wet" limit in WAC 173-434-130(3) Ash Grove applies the following formula:

"Dry" O_2 % = "Wet" O_2 % x (1/(1-(Gas moisture content %/100))

"Dry" O_2 = 3.0% x (1/(1-(10/100))

= 3.0% x 1.11

= 3.3%

Condition II.B.15 requires Ash Grove to continuously monitor the dry oxygen concentration at the preheat tower outlet, and to report as a deviation any 24 hour block during which the average dry oxygen concentration is less than 3.3 percent.

Prohibited Activities

Some of the requirements Ash Grove identified in the operating permit application are included in Section III as prohibited activities. Puget Sound Clean Air Agency has listed these activities in this section to highlight that they cannot occur at the facility. Since these activities are prohibited, routine monitoring of parameters is not appropriate; however, the permit does require Ash Grove to look for such activities during a routine facility-wide inspection.

Puget Sound Clean Air Agency Regulation I, Section 9.13 and WAC 173-400-040(7) contain similar requirements addressing concealment and masking of emissions. Although both requirements apply, the permit language has been simplified by grouping these requirements together. 40 CFR 63.4(b) is included in the Prohibited Activities section of the operating permit with other more general requirements regarding concealment, but it would only be cited if the emission unit was subject to a NESHAPS.

Activities Requiring Additional Approval

Some of the requirements Ash Grove identified in the operating permit application are included in Section IV as activities that require additional approval. For new source review, the permit language has been simplified. Chapter 173-460 WAC and Puget Sound Clean Air Agency Regulation I, Article 6 New Source Review Programs require approval to construct, install, establish, or modify an air contaminant source. All these requirements apply, but the language in these requirements has been incorporated into one section to simplify the permit language. WAC 173-400-110 does not apply within Puget Sound Clean Air Agency's jurisdiction because the rule exempts areas that have a local program that is incorporated into the state implementation plan. Also included in this section are the specific sections in the Part 63 General Provisions pertaining to new source review. This includes 40 CFR 63.5 pertaining to construction and reconstruction of sources subject to 40 CFR Part 63 (NESHAPS).

Reporting and Notification Requirements

Section II.C and II.D contains the reporting and notification requirements applicable to Ash Grove.

The recordkeeping requirements section contains recordkeeping that is both general and specific in nature, depending on the origin of the requirement. There are additional requirements listed under specific emission units in Section II. Ash Grove should refer to these general requirements any time maintenance of records is required.

The reporting requirements section includes both general reporting requirements and reports specific to emission units. The operating permit requires Ash Grove to report deviations of the permit to the Puget Sound Clean Air Agency, normally within 30 days after the end of the month. The operating permit requires that a responsible official certify all required reports at least once every six months. Ash Grove may submit the certification with the report or certify all the reports submitted in the previous six months. For example, if Ash Grove detected a deviation in January, it must report the deviation to the Puget Sound Clean Air Agency in February. A responsible official must certify the report according to WAC 173-401-520 at the time the report is submitted or any other time within six months of submitting the report.

If Ash Grove does not detect any deviations to report for a six-month period, then Ash Grove shall report that there were no deviations during the six-month period.

The notification requirement section includes source testing notification requirements and new source review and change of information notification requirements in 40 CFR Parts 60 and 63.

Standard Terms and Conditions

Some of the requirements Ash Grove identified in the operating permit application are included in Section V, Standard Terms and Conditions. This provided an easier mechanism for describing requirements that are more general in nature. This section also contains the standard terms and conditions specifically listed in WAC 173-401-620.

Section II.C.2 of the permit requires Ash Grove to report deviations of the permit to the Puget Sound Clean Air Agency, normally within 30 days after the end of the month. Section II.C.1 and Section V.Q of the permit requires that a responsible official certify all required reports at least once every six months. Ash Grove may submit the certification with the report or certify all the reports submitted in the previous six months. For example, if Ash Grove detected a deviation in January, it must report the deviation to Puget Sound Clean Air Agency in February. A responsible official must certify the report according to WAC 173-401-520 at the time the report is submitted or any other time within six months of submitting the report.

If Ash Grove does not detect any deviations to report for a six-month period, then Ash Grove shall report that there were no deviations during the six-month period.

Obsolete Requirements

The Puget Sound Clean Air Agency has issued many Notice of Construction Orders of Approval to Ash Grove. Each of these Orders of Approval contains at least one condition that requires Ash Grove to do something one-time, and one-time only. The Puget Sound Clean Air Agency has determined that some of the approval conditions are now informational statements because they have already been complied with and, therefore, do not meet the criteria of being applicable requirements. Those approval conditions are described here.

The NOC Order of Approvals from No. 685 approved January 13, 1972 through NOC Order of Approval No. 2399, approved February 28, 1983 for Ash Grove by Puget Sound Clean Air Agency included one General and some times added a Specific condition. The General Condition was:

"Permission is hereby granted as provided in Article 6 of Regulation I of PSAPCA to APPLICANT to install, alter, or establish the equipment, device, or process described hereon at the INSTALLATION ADDRESS in accordance with the plans and specifications on file in the ENGINEERING DIVISION of PSAPCA. This approval is not a waiver of liability for the infraction of Regulation I nor does it relieve the APPLICANT or OWNER of any requirements of other government agencies."

PSAPCA or Puget Sound Air Pollution Control Agency was the former name of the Puget Sound Clean Air Agency before July 1, 1999

Approval Condition No. 3 in NOC Orders of Approval issued prior to February 6, 1997 (which included Order of Approval No. #2743 approved February 26, 1986 through Order of Approval No. #6644 approved October, 18, 1996), and Condition No. 2 of all other NOC Orders of Approval since Order of Approval No. #2743 inform the applicant that the approval does not relieve it of any requirement of any other agency. This requirement is informational only and is not included in the air operating permit.

The Puget Sound Clean Air Agency considered making Approval Condition No. 1 in all of the NOC Orders of Approval obsolete since it requires the applicant to install the approved equipment according to the specifications submitted to the Puget Sound Clean Air Agency. This requirement has been complied with in all cases as indicated by the submittal of the Notice of Completion to the Puget Sound Clean Air Agency by Ash Grove. However, this requirement was kept in the air operating permit as a reminder that Ash Grove must continue to operate equipment as originally permitted.

Order of Approval No. 6644 is not obsolete, but it does not include specific approval conditions that equate to emission or performance limits or monitoring requirements. It is similar to a the general provision discussed above in that it allowed Ash Grove to use water spray to control dust at two locations in an existing Conveyor System, but it does not specifically require it to be used. Specifically, Condition No. 4 of this order states *"This Order of Approval No. 6644, issued to allow water sprays to control dust at transfer towers #10A and #11, hereby supersedes and cancels Orders of Approval No. 2399 dated Feb 28, 1983 and No. 5696 dated Jan 11, 1995."*. No requirements are missing from the operating permit with the exclusion of this Order. The following table lists all Orders of Approval with obsolete conditions that are not active and not included in the permit.

No.	Approved	Approval Summary	Specific Approval Conditions in Order of Approval?	Status
685	1/13/72	Replace (2) Type 241H Western Precipitator Multiclones Specific: Owner must furnish a source test within 90 days after placing new multiclones in operation showing that emissions from the stack do not exceed the applicable standards of Regulation I, Section 9.09.	Yes	Equipment Removed
918	2/23/73	Upgrade Kiln - ESP Phase I	No	Equipment Removed
1011	7/19/73	Upgrade Kiln - ESP Phase II	No	Equipment Removed
1344	10/25/74	Concrete Supplies Filter Vent Model V16 for Cement Silo	No	Obsolete
1538	4/19/76	Conversion of Cement Process Operation from Natural Gas Firing to Coal Firing & Installing Coal Crusher & Processing Facility Specific: Submit complete source test reports of particulate and SO2 emissions from main stack within 60 days after fuel change is effective. These tests must be made in accordance with all PSCAA test procedures, and observed by this Agency.	Yes	Obsolete
1905	1/4/79	Clinker Storage & Grinding Storage Hall Extension - North Side and Enclosure	No	Obsolete
1918	8/13/79	Plastic Strip Curtains on the East & West End of Packhouse Shipping Shed and on the SE Small Storage Shed. (3) McGuire Pendadors Model DF-400.	No	Equipment Removed

No.	Approved	Approval Summary	Specific Approval Conditions in Order of Approval?	Status
1919	8/13/79	Replace existing Duct Collector at the Belt Conveyor Transfer Point (Tower 11) with a Fuller Plenum Pulse Baghouse @ 5,000 acfm, with 1,001 ft^2 bag area.	No	Obsolete
1920	8/13/79	Replace existing Dust Collector at the Belt Conveyor Transfer Point located immediately West of the Finish Mill Building with a 5,000 acfm Fuller Plenum Pulse Baghouse with 1,001 ft^2 bag area.	No	Equipment Removed
1921	8/13/79	Enclose West Belt Transfer Point - Clinker Unloading - Tower 10	No	Obsolete
1922	8/13/79	Enclosure Belt Transfer Tower 11	No	Obsolete
2305	9/21/81	Rail Car Unloading, (4) Baghouses (Stella Ordered 7/23/02)	No	Equipment Removed
2399	2/28/83	(Cancelled by NOC #6644 10/18/96) Coal Unloading & Stockpiling: consisting of Coal Barge unloading, Coal Discharge pile (4,000 tons), Coal Storage pile (7,500 tons), and existing Conveyors, (3) Baghouses, Coal Silo (600 tons), and Coal receiving station. Specific: Subject to the fugitive dust control requirements and emission offset as described in Lone Star letter dated 1/12/83.	Yes	Cancelled
2743	2/26/86	(1) Fuller Plenum Pulse Baghouse @ 5,000 acfm (Kiln Discharge Elevator), (1) Fabric Filter NW Baghouse @ 7,000 cfm (Barge Unloading), and Construction of Wall & Addition of Rollup Door to enclose the Clinker Storage Shed.	No	Obsolete
2866	2/13/87	Cone Crusher with Water Sprays	No	Equipment Removed
3382	6/19/90	(Cancelled by NOC #5730 12/29/94) Modified Cement Plant (1) Dry process 92 tph (2200 tpd, 750,000 tpy) coal fired cement plant with baghouse control at 177,000 cfm. The plant consists of the following modifications and additions (see attached): Systems 141, 151, 161, 163, 152, 155, 331, 212, 341, 351, 361, 431, 471, 461, 462 and 463 with 24 baghouses of various sizes 4. This source is subject to Subpart F of 40 CFR Part 60. 5. The emissions from the main baghouse shall not exceed the following limits: (a). For Carbon Monoxide (CO): 1000 ppm @ 10% oxygen (O2), 538 pph (pounds per hour) 8-hr average and 2,353 tpy (tons per year);	Yes	Cancelled

No.	Approved	Approval Summary	Specific Approval Conditions in Order of Approval?	Status
		(b) For Nitrogen Oxides (NO_x): 668 ppm @ 10% O2 1-hr average, 590 pph, 422 pph (24-hr average), 478 ppm @ 10% O2 24-hr average, and 1846 tpy. (c) For Sulfur Dioxide (SO_2): 33 ppm @ 10% O2 1-hour average, 40 pph and 176 tpy; (d) For Particulate Matter (PM): 10.6 pph and 46 tpy. 6. The monitoring and reporting of CO, NOx, SO2 and Opacity shall be done in accordance with Article 12 of Regulation I. 7. Emissions of Particulate Matter from all baghouses shall not exceed 0.010 gr/dscf. 8. All emission testing, monitoring and reporting shall be performed in accordance with PSCAA requirements. 9. Offsets of PM emissions (deducted from ERC # 107) are required under this NOC 3382, pursuant to Section 6.08 of Regulation I.		
5006	7/8/93	Addition of a Dry Sorbent Silo (90 tons), venting to a Day 16PJF6 Baghouse @ 750 cfm.	No	Obsolete
5276	1/19/94	(2) Baghouses at 20,000 acfm each connected to the Finish Mill Grinding System. 4. Particulate emissions shall not exceed 0.01 gr/dscf as measured by EPA Method 5 with the back half. Ash Grove shall submit a testing plan to PSCAA for approval within 60 days of the approval date of this Order of Approval. 5. Ash Grove shall perform a compliance source test within 60 days of startup. 6. Ash Grove shall not exceed 10% opacity for an aggregate of 3 minutes in any 1 hour from the baghouse exhaust. 7. Ash Grove shall measure and record pressure drop across the baghouse, and maintain the pressure drop between 3 and 6 inches.	Yes	Active Condition No. 5 is Obsolete
5338	3/15/94	(Replaced by 8415) (1) 150 ton Fly Ash Storage Silo with a 750 cfm Fabric Filter, and a pneumatic conveyor.	No	Cancelled
5351	3/15/94	(1) DCL FS-175 Baghouse at 1,000 cfm for Rail Car Loading.	No	Obsolete
5696	1/11/95	(Cancelled by NOC #6644 10/18/96) Conveying System Modify Raw Material Conveyance System by the addition of	No	Cancelled

No.	Approved	Approval Summary	Specific Approval Conditions in Order of Approval?	Status
		(3) new covered 36' wide Elevated Conveyors at Transfer Tower No. 11 which includes existing Conveyors and (3) existing Baghouses (Ref NOC 2399) to encompass Barge Unloading, Transfer and Stockpiling of Solid Raw Materials and Fuels used in manufacturing of Portland Cement.		
5730	12/29/94	(Cancelled by NOC #7381 6/29/98) Limit PM10 Emissions (5) New Baghouse - Finish Mill This Order of Approval No. 5730 supersedes Order of Approval No. 3382 and adds the installation of a 120 ton/hour Clinker Pre-Grind Crusher with a Baghouse at 20,000 cfm, and a Finish Mill High Efficiency Separator Project including two (2) 60 ton/hour High Efficiency Separators with (2) Baghouses at 77,000 cfm each, two (2) Baghouses at 10,000 cfm each, and one Baghouse at 5,000 cfm. 4. This source is subject to Subpart F of 40 CFR Part 60. 5. PM-10 emissions from each baghouse except the Main Stack baghouse shall not exceed 0.005 grains/dscf over a twenty-four hour period. Ash Grove may demonstrate compliance with this condition by any of the following: a. Performing a PSAPCA approved source test according to EPA Method 5 or EPA Method 201A. b. Demonstrating no visible emissions for 15 consecutive seconds. c. Demonstrating no visible emissions for three consecutive minutes, or d. Repairing within 24 hours, any baghouse that has visible emissions for more than three consecutive minutes. Compliance shall be determined for visible emissions using EPA Method 22. PSCAA may require a source test for any baghouse that has sustained visible emissions, unless such emissions are unavoidable under WAC 173-400-107. 6. Except during startup and shutdown of the kiln, scheduled maintenance and for emissions considered unavoidable under WAC 173-400-107, emissions from the main baghouse shall not exceed the most stringent of PSD limits or the following limits: a. Carbon monoxide (CO): 1049 ppm @ 10% oxygen (O2), 8-hr average, and 2353 tpy (tons per year); b. Nitrogen Oxides (NOx): 700 ppm @ 10% O2 1-hr average, 501 ppm @ 10% O2, 24-hr average, and 1846 tpy. c. Sulfur Dioxide (SO2): 180 ppm @ 10% O2 1-hr average, and 176 tpy.	Yes	Cancelled

No.	Approved	Approval Summary	Specific Approval Conditions in Order of Approval?	Status
		d. Particulate Matter (PM): 10.6 pph and 46 tpy. 7. During startup and shutdown of the kiln, and during scheduled maintenance on the main baghouse, all of the emission limits stated in Condition 6 apply, except that emissions from the main stack shall not exceed 200 ppm of SO2 corrected to 10% O2 for a one-hour average and 1000 ppm of NOx corrected to 10% O2 for a one-hour average. Appendix A to this order defines the startup, shutdown and scheduled maintenance conditions under which these alternate limits apply. 8. Ash Grove shall monitor and report CO, NOx, SO2, and opacity from the main baghouse according to Article 12 of Regulation I. 9. By May 1, 1995, Ash Grove shall submit to PSAPCA for approval a best available control technology determination for controlling fugitive emissions from the clinker discharge end of the kiln. The evaluation must include start up and shut down. 10. Ash Grove shall submit a testing plan to PSAPCA for approval within 60 days of startup for testing of the High Efficiency Separator Baghouse. 11. This Order of Approval supersedes and cancels Order of Approval No. 3382 dated June 19, 1990.		
7381	6/29/98	(Cancelled by NOC #7381 6/6/01) 5 Baghouse - Finish Mill Modifies NOx Emissions Standards This Order of Approval No. 7381 supersedes Orders of Approval No. 3382 and No. 5730 which added the following equipment: a 120 ton/hour Clinker Pre-grind Crusher with a Baghouse rated at 20,000 cfm, and a Finish Mill High Efficiency Separator Project including two 60 ton/hour High Efficiency Separators with two Baghouses rated at 77,000 cfm each, two Baghouses rated at 10,000 cfm each, and one Baghouse rated at 5,000 cfm. 3. This source is subject to Subpart F of 40 CFR Part 60. 4. PM-10 emissions from each baghouse, except the main stack baghouse, shall not exceed 0.005 grains/dscf over a 24-hour period. Ash Grove may demonstrate compliance with this condition by any of the following: (a) Performing a Puget Sound Clean Air Agency-approved source test according to EPA Method 5 or EPA Method 201A; (b) Demonstrating no visible emissions for 15 consecutive seconds; (c) Demonstrating no visible emissions for three consecutive	Yes	Cancelled

No.	Approved	Approval Summary	Specific Approval Conditions in Order of Approval?	Status
		minutes; or (d) Repairing within 24 hours, any baghouse that has visible emissions for more than three consecutive minutes. Compliance shall be determined for visible emissions using EPA Method 22. The Puget Sound Clean Air Agency may require a source test for any baghouse that has sustained visible emissions, unless such emissions are unavoidable under WAC 173-400-107. 5. Except during startup and shutdown of the kiln, scheduled maintenance and for emissions considered unavoidable under WAC 173-400-107, emissions from the main baghouse shall not exceed the most stringent of PSD limits or the following limits: (a) Carbon monoxide (CO) emissions shall not exceed 1049 ppm (parts per million) corrected to 10% oxygen (O_2) for an 8-hour average, and CO shall not exceed 2353 tons per year; (b) Nitrogen oxides (NO_x) shall not exceed 700 ppm corrected to 10% O_2 for a 1-hour average, and NOx shall not exceed 501 ppm corrected to 10% O2, for a 24-hour average, and NOx shall not exceed 1846 tons per year; (c) Sulfur dioxide (SO_2) emissions shall not exceed 180 ppm corrected to 10% O_2 for a one-hr average, and 176 tons per year; (d) Particulate matter (PM) emissions shall not exceed 10.6 pounds per hour, and 46 tons per year. 6. During startup and shutdown of the kiln, and during scheduled maintenance on the main baghouse as defined in Appendix A to this approval, all of the emission limits stated in Condition No. 5 apply, except that emissions from the main baghouse shall not exceed the following limits. (a) During the kiln startup-preheating period prior to kiln feed introduction, the SO_2 emission limit for the main baghouse shall consist of compliance with the following work practices and fuel restrictions: (1) Only natural gas shall be used as fuel, and Appendix A to this approval shall be followed for heating a cold or warm kiln system and system conditioning after maintenance, and (2) Sulfur rings shall be removed from the kiln prior to startup, if sulfur ring formation had required the kiln to be shut down. (b) During the kiln startup-feed introduction period, SO_2 emissions from the main baghouse shall not exceed 200 ppm corrected to 10% O_2 for a one-hr average.		

No.	Approved	Approval Summary	Specific Approval Conditions in Order of Approval?	Status
		(c) Any shutdown of the kiln shall follow the normal rotation and cool down procedures in Appendix A to this approval for the removal of as much material from the kiln as possible without damaging system components. (d) At all times during kiln startup, shutdown and scheduled maintenance, NOx emissions shall not exceed 1000 ppm corrected to 10% O2 for a one-hour average; and (e) Ash Grove shall log as part of the Operations and Maintenance (O&M) Plan and report to the Puget Sound Clean Air Agency as part of the **monthly** Continuous Emission Monitoring Report: (1) The date, start and end times, and the fuel used for kiln startup-preheating periods prior to feed introduction; (2) The sulfur ring removal from the kiln, if the ring formation required the kiln to be shut down; (3) The date, start and end times for kiln startup-feed introduction periods; and (4) The cause for kiln shut down, the duration of kiln cool down and the kiln rotation schedule in kiln cool down. 7. Ash Grove shall monitor and report CO, NO_x, SO_2, and opacity emissions from the main baghouse according to Article 12 of Regulation I. SO_2 emissions from the main stack shall be monitored at all times following the introduction of feed to the kiln. 8. This Order of Approval No. 7381, supersedes and cancels Order of Approval No. 5730 dated Dec 29, 1994.		
8415	3/20/01	Cement Storage Silo vents to existing BH (Replaces NOC 5338) Fuller FK Material Pump and Ramsey Horizontal Rotary Gravimetric Metering System controlled by an existing Fly Ash Storage Silo 750 cfm baghouse.	No	Obsolete

Response to Comments

Public Comment Started 12/31/02

Public hearing on 4/1/03

Public Comment Extended to 4/30/03

Written Comment Summary

Comment 1 (by Ash Grove 1/31/03)

Section I.B1 – Emission Unit #1

Page 9 kiln has nominal capacity of 2400 tons per day.

"This emission unit consists of a nominal ~~2200~~2400 ton/day capacity rotary Portland cement kiln, primarily fired with coal and natural gas, and controlled by a nominal 177,000 acfm baghouse."

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 2 (by Ash Grove 1/31/03)

EU 1.15 and EU 1.18 should state the NSPS emission standards apply at all times except during SSM (startup, shutdown and malfunction) periods.

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)		Reference Test Method
40 CFR Part 60 Subpart F Standards of Performance for Portland Cement Plants						
EU 1.15	40 CFR §60.62(a)(1) 40 CFR § 60.8(c)	10/6/75 2/12/99	Kiln exhaust shall not exceed 0.30 lb of particulate per ton of feed (dry basis), except during SSM periods.			
40 CFR Part 60 Subpart Y Standards of Performance for Coal Preparation Facilities						
EU 1.18	40 CFR 60.252(a)(1) 40 CFR 60.8(c)	10/17/00 2/12/99	Coal mill exhaust shall not exceed 0.031 gr/dscf, except during SSM periods	II.A.1 General Opacity Monitoring II.B.12 Coal ~~Mill NSPS~~Prep Facility Performance Test		

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 3 (by Ash Grove 1/31/03)

Conditions EU 1.18, 1.19 and 2.2 refer to II.B.12, “Coal Mill Performance Test.” Rename monitoring method “Coal Prep Facility Performance Test”.

Condition EU 1.30 prescribes a coal mill performance test from which Ash Grove has requested to be exempted. See letter of January 23, 2003 from Gerald Brown to Steve Van Slyke. In the event that PSCAA is unable to act on this request prior to issuance of the final Title V permit, please revise Condition 1.30 to allow any exemption to take effect automatically.

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)		Reference Test Method
40 CFR Part 60 Subpart Y Standards of Performance for Coal Preparation Facilities						
EU 1.18	40 CFR 60.252(a)(1) 40 CFR 60.8(c)	10/17/00 2/12/99	Coal mill exhaust shall not exceed 0.031 gr/dscf, except during SSM periods	II.A.1 General Opacity Monitoring II.B.12 Coal ~~Mill~~ ~~NSPS~~Prep Facility Performance Test		
EU 1.19	40 CFR 60.252(a)(2) 40 CFR 60.11(c)	10/17/00 10/17/00	Coal mill exhaust shall not exceed 20 percent opacity except during SSM periods	II.A.1 General Opacity Monitoring II.B.12 Coal ~~Mill~~ ~~NSPS~~Prep Facility Performance Test		
40 CFR Part 63, Subparts A and LLL						
EU 1.30	40 CFR 63.1349(b)(3) and (d);	12/6/02	~~Every 30 months~~Except as waived or modified pursuant to 40 CFR 63.7 or 63.8, Ash Grove shall conduct a performance test every 30 months on the kiln			
EU 2.2	40 CFR 60.252(c) 40 CFR 60.11(c)	10/17/00 10/17/00	Exhaust gases shall not exceed 20 percent opacity except during SSM periods.	II.A.1 General Opacity Monitoring II.B.12 Coal ~~Mill~~Prep Facility Performance Test		

Puget Sound Clean Air Agency Response

Comment noted. Identified request is being reviewed and may be resolved with final action prior to the final permit issuance.

Action – Change made to permit.

Comment 4 (by Ash Grove 1/31/03)

EU 1.35, delete, "Ash Grove shall submit the O&M plan for this requirement to the Puget Sound Clean Air Agency for approval." Ash Grove submitted plan on May 24, 2002. We did not see any requirement to submit O&M plan updates for approval. Ash Grove believes this requirement was satisfied by their initial submittal on May 24, 2002.

Reqmt. No.	**Enforceable Requirement**	**Adoption or Effective Date**	**Requirement Paraphrase** (Information Only)	**Monitoring, Maintenance & Recordkeeping Method** (See Section II)		**Reference Test Method**
40 CFR Part 63, Subparts A and LLL						
EU 1.35	40 CFR §63.1350(a)-(b)	12/6/02	Failure to comply with those procedures shall be a violation of Subpart LLL. ~~Ash Grove shall submit the O&M plan for this requirement to the Puget Sound Clean Air Agency for approval.~~			

Puget Sound Clean Air Agency Response

Comment noted. The Agency does not agree with respect to the inapplicability of this requirement for O&M plan amendments to be submitted for review and approval. Since the NESHAP regulation indicates in 40 CFR 63.1350(b) that a "failure to comply with any provisions of the operations and maintenance plan developed in accordance with paragraph (a) of this section shall be a violation of the standard". As such, the version of the O&M plan provisions which relate to compliance with 40 CFR 63, Subpart LLL are important for reporting and compliance purposes. If Ash Grove updated the plan after the initial submittal, the Agency could be reviewing the compliance status of the facility with respect to documents which have not been shared with the Agency and are not part of the source record. If deviations were reported and/or enforcement actions were pending based on O&M plan provisions, it would be important for Ash Grove and this Agency to be working from the same document.

Action – No change made to permit.

Comment 5 (by Ash Grove 1/31/03)

Sections I.B.5 and I.B.6 – Emission Units 5 and 6

Insert standard header bar in the Applicable Requirements Table.

I.B.6 change to Bulk *Bag* Loading Station.

3. Emission Unit #6 (EU-6): Bulk Bag Loading Station

APPLICABLE REQUIREMENTS

Puget Sound Clean Air Agency Orders of Approval NOC 8318 – Bulk Loading Station						
EU-6.1	Puget Sound Clean Air Agency Order of Approval No. 8318 Condition 3.	1/8/01	Ash Grove shall allow no visible emissions or fallout from the 500 cfm baghouse controlling the bulk bag loading station.	II.B.11 Bulk Bag Loading Station Monitoring	NA	NA
EU 6.	Puget Sound Clean Air Agency Order of Approval No. 8318 Condition 5.	1/8/01	If visible emissions, abnormal pressure drop or fallout are observed Ash Grove shall investigate the cause and either initiate repairs or shut down the equipment vented to the baghouse within 24 hours of the observation.	II.B.11 Bulk Bag Loading Station Monitoring	NA	NA

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 6 (by Ash Grove 1/31/03)

Condition II.A.2 – Complaint Response

II.C.4 Add cross reference to new complaint investigation reporting.

2. Complaint Response

Ash Grove shall develop and implement an Air Pollution Complaint Response Program as part of the O&M Plan required by Regulation I Section 7.09(b). The Complaint Response Program shall be annually reviewed and updated along with the O&M Plan. This Program shall include:

- *An Ash Grove local contact person and a 24-hour telephone number;*
- *Complaint forms available to the public;*
- *Criteria and methods for establishing whether Ash Grove may be the source of fugitive dust or other air contaminant impacts on neighboring property;*

- *Format of communicating results of investigations and advising complainants of Ash Grove's corrective actions and preventive maintenance;*
- *Ash Grove shall record air pollution complaints (including those forwarded to Ash Grove from this Agency) and findings of investigations as provided in Condition II.D.6. Investigations shall be initiated within 3 working days of receipt of a complaint.*

  If Ash Grove determines that emissions from its plant unreasonably impacted neighboring properties Ash Grove shall either eliminate the problem within 24 hours of identification or report a deviation as provided in Condition II.C.2. Ash Grove also shall report as a deviation any failure to initiate investigation of a complaint within 3 working days of receipt of the complaint. Results of complaint investigations shall be reported monthly, as provided in Condition II.C.4.

  [WAC 173-401-615(1), 10/17/02]

Puget Sound Clean Air Agency Response

Comment noted, yet the desire to combine the Complaint Response Reports described in II.C.10 of the draft permit does not address the concern identified by Ash Grove [see Comment 16 (by Ash Grove 1/31/03 below] regarding the complaint response procedures. Submitting the Complaint Response Report concurrently with the Monthly CEM Report is acceptable to the Agency. However, inserting this separate reporting requirement as a component of the Monthly CEM Report could be misleading to the public. Combining the reports into one reporting requirement will not reduce any paper or reporting requirements under this permit and would at a minimum, require a change to the report description identified in II.C.4 of the permit (e.g. Monthly CEM and Complaint Response Report).

Action – No change made to the permit for this comment.

Comment 7 (by Ash Grove 1/31/03)

Condition II.A.3 – Rooftop Inspection

Page 31, footnote 1, define a “roof-top inspection” as a *visual* inspection of the overall facility.

3. Roof Top Inspections

Ash Grove shall conduct a roof-top[1] inspection at least weekly. These inspections shall include inspection for odor-bearing contaminants and for fugitive emissions from any part of the facility. In the event any fugitive emission release is discovered by an inspection, Ash ~~grove~~Grove shall as soon as possible, but no later than 24 hours after discovered, begin corrective action, shut the ~~operaton~~operation down until the problem can be corrected, or report the release as a deviation as provided in Condition II.C.2. Ash Grove shall document each inspection as provided in Condition II.D.5.

[WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02]

[1] A "roof-top inspection" is ~~an~~a visual inspection of the overall facility from a sufficient height to allow the determination of the point(s) of origin and possibly the cause(s) of fugitive emissions.

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 8 (by Ash Grove 1/31/03)

Condition II.B.2 – SO2, CO and NOx CEMS

Paragraph iii, update Appendix B performance specifications reference date to 1992, EPA's performance specifications in effect when CEMS Reg I § 12.03(c).

[See "*Comment 24 (by Ash Grove 1/31/03)*" below for more discussion of this comment.]

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 9 (by Ash Grove 1/31/03)

Condition II.B.3 – SO2, CO and NOx Mass Emission Rate Monitoring

Clarify annual CO and SO2 limits as calendar year limits and 8-hr CO limit is block average limit with 3 intervals per day. Add cross-references of reporting & recordkeeping. Delete recordkeeping requirements and add II.D.10. Reference PSD permit, which requires monitoring described in this condition.

3. SO2, CO, and NOx Mass Emission Rate Monitoring

Ash Grove shall calculate ~~annual~~SO2 and CO emissions ~~of SO2, CO~~from the cement kiln operation on a calendar year basis, and NOx emissions from the cement kiln operation on a 12-month rolling total basis, using the CEMS data collected under the requirements of Section II.B.2 of this permit. Additionally, Ash Grove shall calculate the 8-hour block average mass emission rate for CO using ~~on~~ CEMS data collected under the requirements of Section II.B.2 of this permit. Each day shall consist of three 8-hour compliance intervals, the first interval commencing at 12:00 a.m. When CEM data is not available or not required to be collected as identified by this permit, other information available to Ash Grove shall be used to compile the emission rate values. ~~The CEM data conversions used to generate mass emission rate values for these calculations shall be documented and retained with the record. Other supplemental emission rate determinations used for operational periods lacking CEM data shall also be documented (and retained with the record) to complete the annual emission rate calculation.~~Report deviations as provided in Condition II.C.4. Maintain records as provided in Condition II.D.10.

[WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02~~][~~; Order of Approval No. 7381, Condition 7, 6/6/01; PSD Permit 90-03, Amendment 3, Conditions 1-3, 10/8/01]

Puget Sound Clean Air Agency Response

Comment is essentially correct. A review of the specific language in the referenced PSD approval does not specify calendar year on the annual emission limitations. The specific language in Order of Approval No. 7381 Condition No. 5(b) identifies the annual NOx limitation as a “12-month running total”. In contrast, the annual limitations for SO2 and CO have no parallel language regarding “running total”. This is indicative that the annual limitations have been approved on different calculation bases and the comment from Ash Grove is correct. Additionally, the comment on the 8-hour CO concentration limit as three 8-hour blocks of CO data for a 24-hour operational period is also correct. This comment merely reflects the parallel treatment of 1-hour concentration limits as 24 blocks of monitor data for each 24-hour operating day. The comment on linkage to recordkeeping in II.D.10 of the permit is also appropriate [*see discussion below on Comment 18 (by Ash Grove 1/31/03)*].

Action – Change made to permit.

Comment 10 (by Ash Grove 1/31/03)

Condition II.B.9 – PM Monitoring Main Baghouse

Propose modifying subsection (b) to clarify adjusting PM10 emission factor for only future reporting intervals.

9. PM Monitoring Main Baghouse

(b) ~~**Initially, multiply**~~Multiply the ~~annual~~calendar year tonnage of clinker production by an emission factor of 0.0414 kg/Mg to determine annual PM10 emissions. ~~Recalculate~~Revise this emission factor using data from the most recent PM source test, provided that the test yields data deemed representative of the kiln baghouse emission rate. Use the revised emission factor to calculate annual emissions for years subsequent to receipt of the source test data. Record in a log the annual tonnage of clinker production. Report per Condition II.C.2 if calendar year PM emissions exceed 46 tons per year.

Puget Sound Clean Air Agency Response

Comment is noted and the Agency agrees with the comment with one exception. The revised emission factor to calculate annual emissions should be for subsequent years following the date of the source test rather than the date of receipt of the source test. Since the calculation is completed on a calendar year basis, this would eliminate the possibility that a source test result from a test completed in December would not be used for 13 months as a result of the necessary elapsed time to produce a source test report.

Action – Change made to the permit, with the exception noted above for test date rather than report receipt.

Comment 11 (by Ash Grove 1/31/03)

Condition II B.11 – Bulk Loading Station Monitoring

Propose "Bulk *Bag* Loading Station Monitoring," to distinguish form bulk truck loading station.

11. Bulk Bag Loading Station Monitoring

At least once a week when the bulk bag loading station is in operation, Ash Grove shall inspect the dust collector for visible emissions, fallout and pressure drop across the filters.

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 12 (by Ash Grove 1/31/03)

Condition II.B.12 – Coal Mill NSPS Performance Test

Propose renaming "Coal Prep Facility Performance Test." NSPS Subpart Y requires opacity and grain loading tests on coal mills, and an opacity test on units of Condition I.B.2. Need to address all performance tests required by Subpart Y.

12. Coal ~~Mill NSPS~~Prep Facility Performance Test

Within 180 days of permit issuance, Ash Grove shall conduct ~~a~~an NSPS performance test to show compliance with Condition EU 1.18 (40 CFR 60.252(a)(1) ~~and 60.252(a)(2) (Requirement EU 1.18,~~) (coal mills only) and Conditions EU 1.19 and ~~EU~~ 2.2 (40 CFR 60.252(a)(2) (all Subpart Y affected facilities). Source testing methods required by 40 CFR 60.254 shall be used ~~the~~. The procedures identified in Sections V.N and V.P of this permit shall apply.

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 13 (by Ash Grove 1/31/03)

Condition II.C.4 – Monthly CEM Report

Propose adding language after condition for monthly reports June to December for semi-annual reports per II.C.5, 6 and 7 and add paragraph for complaint investigations in a month, replacing II.C.10.

C. Reporting

4. Monthly CEM Report

Ash Grove shall file with Puget Sound Clean Air Agency a monthly CEM report, which shall be delivered or postmarked within 30 days after the end of the month in which the data were recorded. This report shall include:

a. Results of any complaint investigations conducted pursuant to Condition II.A.2;

b. The monthly CEM reports for June and December shall include, as attachments, the reports required by Conditions II.C.5, II.C.6 and II.C.7.

Puget Sound Clean Air Agency Response

Comment noted. The Agency agrees with the comment and suggestion for insertion of paragraph (j) regarding attachment of reports required by Conditions II.C.5, II.C.6 and II.C.7. Based on the discussion above [Comment 6 (by Ash Grove 1/31/03)], the Complaint Response Report may be attached to the Monthly CEM Report but it will remain a distinct reporting requirement.

Action – Insert (i) to the permit stating "Complaint Response Report required by Condition II.C.10 shall be included as attachments to the CEM Report". Insert (j) as suggested by the comment.

Comment 14 (by Ash Grove 1/31/03)

Condition II.C.6 – Semi-annual NESHAPS Subpart LLL Summary Report

Propose edit of (i) for tracking excess emissions on the kiln and coal mills.

6. Semi-annual NESHAPS Subpart LLL Summary Report

i. Performance summary, including each three hour period during the reporting period in which the average temperature of the kiln and/or each of the coal mills exceeded the respective temperature limits for those units as set forth in Conditions EU 1.29 and 1.30, the total duration of excess emissions expressed as a percent of the total kiln and/or coal mill operating time during the reporting period, and a breakdown of the total duration of excess emissions into those that are due to startup, shutdown, control equipment problems, process problems, other known causes and unknown causes;

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 15 (by Ash Grove 1/31/03)

Condition II.C.7 – Semi-annual NESHAPS Subpart LLL SSM Report

Propose edit of SSM report for each kiln SSM event, as in 40 CFR 63.10(d)(5)(i). Propose adding Part 63 definition "malfunction," to know which events to report.

7. Semi-annual Subpart LLL Startup Shutdown and Malfunction Report

The monthly CEM reports for June and December shall include, as an attachment, a semi-annual Subpart LLL SSM report. The SSM Report shall list the number, duration and a brief description of each kiln startup, shutdown or malfunction during the reporting period. If actions taken by Ash Grove during SSM events occurring between January 1 and June 30 of each year were consistent with the procedures in Ash Grove's SSM plan the ~~monthly CEM~~ report for the month of June shall include a statement to that effect. If actions taken by Ash Grove during SSM events occurring between July 1 and December 31 of each year were consistent with the procedures in Ash Grove's SSM plan the monthly ~~CEM~~ report for the month of December shall include a statement to that effect. For purposes of this report a "malfunction" means any sudden, infrequent, and not reasonably preventable failure of kiln air pollution control equipment or the kiln process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[40 CFR 63.10(d)(5)(i) (4/5/02); 40 CFR 63.2 (4/5/02); 40 CFR 63.1354(b)(4) (6/14/99); WAC 173-401-615(3) (10/17/02)]

Puget Sound Clean Air Agency Response

Comment noted. Referenced malfunction definition is correct for 40 CFR Part 63.

Action – Change made to the permit, as modified by a related subsequent comment *[see Comment 26 (by Ash Grove 2/13/03)]*.

Comment 16 (by Ash Grove 1/31/03)

Condition II.C.10 – Complaint Response Reporting

This condition as proposed is impractical and unrealistic because it assumes that all complaints will be determined to be "attributable to Ash Grove" or not attributable. Much of the time a conclusive determination cannot be made, for reasons including the age of the complaint, the inability to collect a sample, or if the particulate analyzed in a sample does not bear the chemical fingerprint of cement products. Ash Grove is willing to report on the results of every complaint investigation conducted pursuant to Condition II.A.2, as part of the monthly CEM report described in Condition II.C.4,. We propose to delete this condition and to add a new paragraph to II.C.4 to require reporting the results of every complaint investigation.

Puget Sound Clean Air Agency Response

Comment noted and the Agency agrees that not all complaints will be decisively attributable to Ash Grove. Ash Grove's suggestion to report on all complaints will help illustrate for others the level of effort associated with complaint response and will be included in the permit. The scope and the nature of the complaint response requirement identified in Condition II.A.2 are discussed in more detail below [see Comments 39 through 45 (by Port of Seattle 4/30/03)]. Also, the desire to delete Condition II.C.10 was discussed previously [see Comment 6 (by Ash Grove 1/31/03)] and it will remain a part of the permit.

Action – Condition II.A.2 of the permit was modified as discussed in the referenced comments above.

Comment 17 (by Ash Grove 1/31/03)

Condition II.D.8 – NESHAPS Subpart LLL Recordkeeping

Delete reference to 40 CFR 63.10(b)(2)(vii)(A) in paragraph (g) because temperature CMS is not subject to that paragraph.

Puget Sound Clean Air Agency Response

Comment noted and is correct. However, the citation needs to be corrected rather than removed. The correct citation should be 40 CFR 63.10(b)(2)(vii) rather than 40 CFR 63.10(b)(2)(vii)(A). The text in paragraph (vii)(A) is referring to CEMS data, which is not used for NESHAP compliance monitoring. However, paragraph (vii) refers to CMS data the temperature monitoring provisions of the NESHAP that apply to Ash Grove are used for NESHAP compliance monitoring.

Action – Change made to permit as discussed above.

Comment 18 (by Ash Grove 1/31/03)

Condition II.D.10 – SO2, CO and NOx Mass Emission Rate Recordkeeping

Proposes edits agree with proposed in change of Condition II.B.3. See II.B.3.

D. Recordkeeping

10. SO2, CO, and NOx Mass Emission Rate Recordkeeping

Ash Grove shall maintain on site records which document the 12-month rolling total ~~annual emission~~ calculations for ~~SO2, CO, and~~ NOx emissions from the kiln, the calendar year calculations for CO and SO2 emissions from the kiln and summary 8-hour block average CO mass emission rates from the ~~cement~~ kiln. The records shall include the monthly calculations for each annual pollutant value, sufficient documentation to demonstrate the conversions from CEM data to mass emission rates, sufficient documentation to demonstrate the calculation methods used for mass emission rate data that is not CEM based, and documentation showing that all kiln operational time is included in the totals. The CEM data conversions used to generate mass emission rate values for these calculations shall be documented and retained with the record. Emission rate estimates used for operational periods lacking CEM data also shall be documented and retained.

Puget Sound Clean Air Agency Response

Comment noted and the suggestions are consistent with previous comment and response [see Comment 9 (by Ash Grove 1/31/03)].

Action – Change made to the permit to reflect this suggestion.

Comment 19 (by Ash Grove 1/31/03)

Condition V.O – Credible Evidence

The second paragraph of this condition overstates the scope of the credible evidence rules cited as legal authority for the paragraph. 40 CFR 52.12(c) states that nothing in Part 52 (i.e., the PSD rules and the Washington SIP) precludes the use of any credible evidence. 40 CFR 52.33(a) says that nothing in Part 52 or in any Federal Implementation Plan shall preclude the use of any credible evidence. Neither of these regulations addresses whether other Clean Air Act provisions, notably the Title V permit shield, may limit the use of any credible evidence in an enforcement dispute. We do not ask PSCAA to resolve today the question of how the credible evidence rule interacts with the permit shield. We do request that PSCAA preserve the question for another day by amending the second paragraph of Condition V.O to track the language of the federal rules cited as authority for this condition.

V. STANDARD TERMS AND CONDITIONS

O. Credible Evidence

For purposes of Federal enforcement, nothing in ~~*any Federally enforceable State or Puget Sound Clean Air Agency regulation, permit, or order*~~40 CFR Part 52 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether Ash Grove would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed.

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit to reflect earlier language proposed by Ash Grove. Section V.O of the permit will read as follows:

V.O Credible Evidence

For the purpose of establishing whether or not a person has violated or is in violation of any provision of chapter 70.94 RCW, any rule enacted pursuant to that chapter, or any permit or order issued thereunder, nothing in Puget Sound Clean Air Agency Regulation I shall preclude the use, including the exclusive use *of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed.*

[Puget Sound Clean Air Agency Regulation I, Section 3.06 (10/08/98); State/Puget Sound Clean Air Agency only]

For purposes of Federal enforcement, nothing in 40 CFR Part 52 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed.

[40 CFR 52.12(c) and 52.33(a) (2/24/97)]

Comment 20 (by Ash Grove 1/31/03)

Condition V.Q – Certification of Truth, Accuracy and Completeness

There is some stray boilerplate inserted between Conditions V.Q and V.R. It addresses Ecology rules prohibiting sources from tampering with monitoring devices, or making false statements. We propose to move these requirements into Section III of the permit, and to list each of them as its own permit condition.

V. STANDARD TERMS AND CONDITIONS

Q. Certification of Truth, Accuracy and Completeness

~~“No person shall render inaccurate any monitoring device or method required under Chapter 70.94 RCW, or any ordinance, resolution, regulation, permit, or order in force pursuant thereto.”~~

~~[WAC 173-400-105(8), 8/21/98 *STATE ONLY*]~~

~~"No person shall make any false material statement, representation or certification in any form, notice, or report required under Chapter 70.94 RCW, or any ordinance, resolution, regulation, permit, or order in force pursuant thereto.”~~

~~[WAC 173-400-105(7), 8/21/98 *STATE ONLY*]~~

III. PROHIBITED ACTIVITIES

G. Tampering

Ash Grove shall not render inaccurate any monitoring device or method required under Chapter 70.94 RCW, or any ordinance, resolution, regulation, permit or order in force pursuant thereto. [WAC 173-400-105(8), 8/21/98 *STATE ONLY*]

H. False Statements

Ash Grove shall not make any false material statement, representation or certification in any form, notice or report required under Chapter 70.94 RCW, or any ordinance, resolution, regulation, permit or order in force pursuant thereto. [WAC 173-400-105(7), 8/21/98 *STATE ONLY*]

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit to reflect suggestion in this comment.

Comment 21 (by Ash Grove 1/31/03)

Section VIII – Inapplicable Requirements

This condition includes two tables, one for requirements determined to be inapplicable to the entire plant, and the second for requirements determined to be inapplicable to a particular emission unit or units. The second row in the second table, discussing NSPS Subpart OOO, should be moved into the first table, because it finds that there are no Subpart OOO affected facilities at the Seattle plant.

The fifth row in Table 2, dealing with 40 CFR 60.8 performance tests, contains an editorial comment that should be deleted from the permit. The "Basis for Nonapplicability" column includes a statement that "Performance test for the coal mill is included in this permit in Section II.B.12." This statement should be deleted, because it simply restates a requirement found in Section II.B.12.

The tenth row in the second table contains a statement that is now obsolete. Please delete "and the test report and compliance notification will be submitted as identified in Section II.C.8 of this permit." Those reports were filed on December 20, 2002.

The 12th, 13th and 14th rows in the second table contain incomplete citations to Portland Cement MACT regulations. Please correct these errors as shown in the attached redline of the permit.

VIII. INAPPLICABLE REQUIREMENTS

Citation	Type of Requirement	Basis for Nonapplicability
PSD Permit 90-03 (6/20/90) and Amendments 1 (11/7/95) and 2 (3/8/99)	PSD Permit	These versions of Permit 90-03 were superseded by Amendment 3 (10/8/01).
40 CFR Part 60, Subpart OOO	NSPS for Nonmetallic Mineral Processing Plants	40 CFR 60.670(b) states that a Subpart OOO "affected facility" that is subject to Subpart F or that follows in the plant process any facility subject to Subpart F is not subject to Subpart OOO. All equipment at the Seattle plant that falls within the Subpart OOO definition of "affected facility" is also a Subpart F "affected facility."
Puget Sound Clean Air Agency Approval Orders 3382, 5730 and 7381 (6/29/98)	New source approval orders	Superseded by Order of Approval 7381, condition 8 (6/6/01)

Citation	Type of Requirement	Basis for Nonapplicability
The requirements that are identified below are inapplicable for specific emission units or for rule and unit specific reasons. The requirements identified in the first column for these subsequent items are inapplicable only insofar as the scope and explanation provided in the third column qualifies the limitation of inapplicability and are not universally inapplicable to the entire site or for this permit beyond that scope and explanation.		
~~40 CFR Part 60, Subpart OOO~~	~~NSPS for Nonmetallic Mineral Processing Pants~~	~~40 CFR 60.670(b) states that a Subpart OOO "affected facility" that is subject to Subpart F or that follows in the plant process any facility subject to Subpart F is not subject to Subpart OOO. All equipment at the Seattle plant that falls within the Subpart OOO definition of "affected facility" is also a Subpart F "affected facility."~~
40 CFR 60 Part 60, Subpart F	NSPS for Portland Cement Plants	Clinker storage shed, finish mills, steel scale tanks and Group II silos are not Subpart F "affected facilities" because neither unit was constructed or modified after August 17, 1971. 40 CFR 60.60(b) (7/25/77).
40 CFR 60.8	Initial performance test	Requirement to conduct NSPS initial performance test on the kiln was satisfied on 6/17/93. ~~Performance test for the coal mill is included in this permit in Section II.B.12.~~
40 CFR 63.7 and 63.1349(a) and (b)	MACT initial performance test requirements	The requirement to conduct a performance test to demonstrate initial compliance with the dioxin/furan emission standards in 40 CFR 63.1343(d) was satisfied on October 22-24, 2002 and the 2002. The test report and compliance notification will be submitted as identified in Section II.C.8 of this permit on December 20, 2002.
40 CFR 135063.1350(g)	Dioxin/furan monitoring requirements for kilns that employ carbon injection as an emission control technique	The Seattle plant does not employ carbon injection as an emission control technique.
40 CFR 135163.1351(b)	Subpart LLL compliance date for affected sources that commence new construction or reconstruction after March 24, 1998	Ash Grove did not commence new construction or reconstruction on any Subpart LLL affected source after March 24, 1998.
40 CFR 134463.1344(b)	Temperature limit for affected sources determined through performance test	The procedure in 40 CFR 1344(b) to set the temperature limit for affected sources through measurements taken during dioxin/furan performance testing does not apply to the coal mills, because Puget Sound Clean Air Agency approved an intermediate monitoring change establishing the coal mill temperature limit at 200 degrees F. See letter of October 18, 2002 from Steven Van Slyke to Robert Vantuyl.

Puget Sound Clean Air Agency Response

Comment noted.

Action – The Agency agrees with the first element (move the reference to 40 CFR Part 60, Subpart OOO from the list of specifically noted inapplicable requirements to the plan-wide noted inapplicable requirements), the third element (reference to wording changes in 40 CFR 63.7 and 63.1349(a) and (b)), and the fourth element (expanding the wording from 40 CFR 1350(g), 40 CFR 1351(b) and 40 CFR 1344(b) to 40 CFR 63.1350(g), 40 CFR 63.1351(b) and 40 CFR 63.1344(b)) of these comments and the requested changes to the permit will be made as requested.

The comment regarding the citation for 40 CFR 60.8 as it relates to the initial performance tests illustrates how this citation could be confusing. Ash Grove's comment suggests that an initial performance test should be cited as an inapplicable requirement. The comment included in the draft permit to explain why that inapplicability would be true identifies that the performance test for the Coal Mill has not been completed and is identified as a permit term in the draft document. Deleting the reference to a test that will be completed does not clarify the basis for inapplicability for this requirement with respect to 40 CFR 60, Subpart Y. Ash Grove identified the applicability of this NSPS rule in developing the draft permit.

The interest of this Agency is not whether the performance test identified in Section II.B.12 of the draft permit is an "initial" performance test but rather that a performance test is completed and documented for the record to satisfy the NSPS requirement. Since the understanding of 40 CFR 60, Subpart Y applicability evolved for both the source and this Agency, it will suffice to complete the performance test as identified in the draft permit. As a result, this Agency is deleting the 40 CFR 60.8 citation from the Inapplicable Requirements table. A performance test was completed on June 17, 1993 on the cement kiln to satisfy the performance test requirements of 40 CFR 60, Subpart F and the permit identified performance test for the coal mill in Section II.B.12 of the permit will satisfy the performance test requirement 40 CFR 60, Subpart Y. Since 40 CFR 60.8 addresses all performance tests, regardless of whether it is an initial or subsequent performance testing event, identifying a portion of this regulation as inapplicable is confusing.

Comment 22 (by Ash Grove 1/31/03)

Section IX – Insignificant Emission Units

The "Lignoute Tank" mentioned in the IEU table should be a "Lignite Tank."

VIII. INSIGNIFICANT EMISSION UNITS

A. Insignificant Emission Units and Activities

Unit	Basis for IEU Designation
~~Lignoute~~Lignite Tank	WAC-173-401-533(2)(c)

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 23 (by Ash Grove 1/31/03)

Section X – Appendices

Ash Grove does not see any need to attach the test methods and EPA QA manual for COMS referenced in Conditions X.B and X.D. Ash Grove and PSCAA each have copies of these documents.

X. APPENDIXES

B. Non-EPA Test Methods (~~attached)~~by reference only)

C. Reference Continuous Emission Monitoring Performance Specification (by reference only, not attached)

(1) EPA Performance Specification 1 (Opacity Monitoring), [40 CFR 60, Appendix B, July 1, ~~1997]~~1992]

(2) EPA Performance Specification 2 (SO2 and NOx Monitoring) [40 CFR 60, Appendix B, July 1, ~~1997]~~1992]

(3) EPA Performance Specification 3 (O2 Monitoring) [40 CFR 60, Appendix B, July 1, ~~1997]~~1992]

(4) EPA Performance Specification 4 (CO Monitoring) [40 CFR 60, Appendix B, July 1, ~~1997]~~1992]

D. EPA Quality Assurance Procedures (~~attached)~~by reference only)

Continuous Emission Monitoring for Opacity: "Recommended Quality Assurance Procedures for Opacity Continuous Monitoring Systems" (EPA 340/1-86-010)

E. Elements of Opacity COMS Summary Report for 40 CFR 60.7(d) (Condition II.C.5)

Pollutant ~~(i.e., NOx, CO, SO2, Opacity)~~: opacity; Reporting period dates; Company name and address; Process unit(s) description; Emission limits; Monitor manufacturer and model no.; Date of latest CMS Certification or Audit; Total source operating time in reporting period[1]

Include Name and Signature (Title) of the responsible official and Date

1. For Opacity, record all times in minutes. ~~**For gases, record all times in hours.**~~

Puget Sound Clean Air Agency Response

Comment noted. The Agency disagrees with this comment about attachments. The distinction between attached and referenced appendix materials was considered during the draft permit development and the choice was based on the relative ease to access and/or retrieve the documents. Public access to this information is also a consideration.

Action – No change made to permit.

Comment 24 (by Ash Grove 1/31/03)

The references to CEMS performance specifications in Section X.C.(1) should be dated 1992, rather than 1997. Regulation I § 12.03(c) states that a CEMS shall meet the performance spec in 40 CFR Part 60, Appendix B "in effect at the time of its installation." This rule is reflected in permit conditions II.B.1 and II.B.2, which reference the 1992 versions of each performance spec. To be consistent Section X.C.(1) also should cite the 1992 versions.

[See comment 23 for suggested language changes.]

Puget Sound Clean Air Agency Response

Comment noted. The CEMS equipment was installed as required by Order of Approval No. 3382. That Order of Approval had an approval date of June 19, 1990 and the installation was reported to be complete on November 1, 1992.

Action – Change made to permit.

Comment 25 (by Ash Grove 1/31/03)

The NSPS Summary Report format incorporated in Section X.E.1 should be revised to apply solely to data from Ash Grove's opacity COMS. While the Seattle plant contains several CEMS, the only one required by an NSPS is the opacity COMS on the kiln. For this reason only the opacity COMS is subject to the semi-annual report required by 40 CFR 60.7(d). All of Ash Grove's CEMS are subject to monthly reporting required by Regulation I § 12.03(f). The additional report required by 40 CFR 60.7(d) is required only of the opacity COMS.

[See comment 23 for suggested language changes.]

Puget Sound Clean Air Agency Response

Comment noted.

Action – Change made to permit.

Comment 26 (by Ash Grove 2/15/03)

From: Cohen, Matthew (for Ash Grove)

Sent: 2/12/03

Proposes words for proposed 40 CFR 63.10(d)(5)(i) for SSM Plan in II.C.7.

The monthly CEM reports for June and December shall include, as an attachment, a semi-annual Subpart LLL SSM report. The SSM Report shall list the number, duration and a brief description of each Part 63 startup, shutdown and malfunction during the reporting period. The requirement to report startups and shutdowns is deleted on the effective date of a rule change amending 40 CFR 63.10(d)(5)(i) to delete the requirement to report startups and shutdowns. . . .

Puget Sound Clean Air Agency Response

Comment noted. The proposed rule referenced by this comment was promulgated and effective on May 30, 2003. The previous comment relating to Condition II.C.7 *[see Comment 15 (by Ash Grove 1/31/03)]* is modified and superceded by this comment and the EPA finalization of this regulation.

Action – Change made to permit. Condition II.C.7 is revised to read as follows:

7. Semi-annual Subpart LLL Startup Shutdown and Malfunction Report

The monthly CEM reports for June and December shall include, as an attachment, a semi-annual Subpart LLL SSM report. The SSM Report shall list the number, duration and a brief description of each kiln startup, shutdown or malfunction during the reporting period. If actions taken by Ash Grove during SSM events occurring between January 1 and June 30 of each year were consistent with the procedures in Ash Grove's SSM plan, the SSM report for the month of June shall include a statement to that effect. If actions taken by Ash Grove during SSM events occurring between July 1 and December 31 of each year were consistent with the procedures in Ash Grove's SSM plan the SSM report for the month of December shall include a statement to that effect. Each SSM report shall identify any instance where an action taken by Ash Grove during and SSM event (including actions taken to correct a malfunction) is not consistent with the SSM Plan but the kiln and/or coal mill did not exceed an emission limit in Conditions EU 1.26 through 1.29. The report shall also include the number, duration and brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused an emission limit in Conditions EU 1.26 through 1.29 to be exceeded. For purposes of this report a "malfunction" means any sudden, infrequent, and not reasonably preventable failure of kiln air pollution control equipment or the kiln process to operate in a normal or usual manner which causes, or has the potential to cause, any of the emission limitations in Conditions 1.26 through 1.29 to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[40 CFR 63.10(d)(5)(i) (5/30/03); 40 CFR 63.2 (5/30/03); 40 CFR 63.1354(b)(4) (6/14/99); WAC 173-401-615(3) (10/17/02)]

Comment 27 (by Ash Grove 3/28/03)

From: Cohen, Matthew (for Ash Grove)

Sent: 3/28/03

Source requested an extension of comment period to prepare comments regarding potential applicability of WAC Chapter 173-434 to the Ash Grove Seattle plant.

Puget Sound Clean Air Agency Response

Comment noted.

Action – Comment period extended through April 30, 2003.

Comment 28 (by Ash Grove 4/30/03)

A. WAC 173-434

Section VIII of the draft permit contains a finding that the Seattle plant is not subject to WAC ch. 173-434[2] because the plant is not a solid waste incinerator facility. PSCAA has asked Ash Grove to support this finding, in light of the Pollution Control Hearings Board opinion in City of Tacoma Department of Public Works v. Department of Ecology, PCHB No. 02-020.

The City of Tacoma decision involved the Tacoma Steam Plant, a 1931 coal-fired electric power generating plant that was converted in 1986 to perform dual functions as a solid waste incinerator and energy recovery plant. WAC ch. 173-434 applies to any "incinerator facility," defined in WAC 173-434-030 to mean "all of the emissions unit(s) . . . whose activities are ancillary to the incineration of solid waste." Tacoma argued that the Steam Plant is not an incinerator facility because its primary purpose is to generate electricity, not to dispose of solid waste. Tacoma relied in part on the WAC 173-400-030 definition of "incinerator," which refers to "a furnace used primarily for the thermal destruction of waste." The Board rejected this argument, holding that "the term 'incinerator facility' broadens the regulatory scope to include units whose burning of solid waste may be only 'ancillary' to its primary purpose." Order Granting Summary Judgment at 6.

The Board did not explain its interpretation of the terms "ancillary" or "incineration of solid waste." Nor did the Board reconcile its decision with the first sentence of WAC 173-434-030, which declares that "the definitions of terms contained in chapter 173-400 are incorporated by reference."

Assuming, however, that the PCHB decision is correct and binding, Ash Grove's Seattle plant clearly is not an "incinerator facility," because the combustion of solid waste is neither its primary nor its ancillary function.[3] Ash Grove operates the kiln exclusively to produce cement clinker. The production of clinker requires a great deal of energy and large volumes of raw materials. The compounds required to manufacture clinker include calcium, silica, alumina and iron oxides. Ash Grove extracts these compounds from a mix of virgin materials, industrial byproducts and recycled tires. The secondary raw material streams and the quantities processed in 2002 are as follows:

- bottom ash from Centralia coal plant – 105,000 tons
- slag from the Trail zinc smelter – 18,000 tons
- recycled tires – 5500 tons
- trim chips from James Hardie Gypsum – 4000 tons

[2] The permit erroneously cites the solid waste incinerator rules as WAC ch. 173-435. This error should be corrected in the proposed version of the permit.

[3] Webster defines "ancillary" using the following synonyms: subordinate, subsidiary, auxiliary and supplementary. Webster's New Collegiate Dictionary (1981).

Ash Grove uses each of these products to recover constituents required for clinker production. Bottom ash supplies alumina. Trail slag supplies iron. Gypsum chips provide silica. Recycled tires provide not only silica and iron[4] but also a supplemental fuel source that displaces coal.

The calcium, silica, alumina and iron compounds contained in Centralia bottom ash, Trail slag and gypsum chips have commercial value. To obtain them Ash Grove must purchase these materials for fair market value. There is no local secondary market for used tires. As a result recyclers pay Ash Grove a small fee to accept them, in lieu of land filling the tires.

The use of tires as a supplemental fuel and raw material source has two collateral environmental benefits. First, tire consumption generates less NOx than coal, on a pound per ton of clinker basis. Ash Grove reduced NOx emissions in 2002 by about 100 tons by exploiting the fuel and raw material values found in tires. Second, tire consumption recovers materials and energy from a waste stream that otherwise would consume landfill capacity.

The clinkering process produces no ash or other waste material. One hundred percent of the secondary materials inserted into the kiln are absorbed into clinker.

By contrast, the Tacoma Steam Plant was designed to serve two functions: energy generation and thermal destruction of municipal solid waste (MSW). Declaration of Jay Willenberg ¶ 9, PCHB No. 02-020 (filed May 10, 2002). In its application for a state solid waste grant to retrofit the plant the City explained that the primary purpose of the retrofit "is to reduce the volume of solid waste entering the Tacoma landfill while attempting to maximize the energy potential in the solid waste." Declaration of Peter Lyon ¶ 8, PCHB No. 02-020 (filed May 10, 2002). The Steam Plant proved to be economically unviable if it could not be used to combust MSW. Declaration of Douglas Walker In Support of Motion For Summary Judgment ¶ 9, PCHB No. 02-220 ("The City, NRG and TERC have agreed to temporarily suspend operation of the Steam Plant indefinitely due to economics and the inability of the plant to obtain the necessary operating permits for burning alternative fuels."). The Steam Plant produced no product other than energy. The waste combusted in the plant had no raw material value, and no commercial value. On this record, the PCHB found that the combustion of solid waste was at least an "ancillary" purpose of the Tacoma Steam Plant. Order Granting Summary Judgment at 6.

How can PSCAA support a determination Ash Grove is not an "incinerator facility"?

- Ash Grove, unlike the Tacoma Steam Plant, was designed and operates exclusively to produce cement clinker. The thermal destruction of solid waste is neither a principal nor an ancillary function of the plant.
- Ash Grove accepts *only* those secondary materials that provide constituents needed to produce clinker. Tires in particular supply about 10 percent of the iron required to produce clinker.

[4]The average passenger car tire contains 2.5 pounds of steel. On a typical day recycled tires supply almost 10 percent of the Fe_2O_3 required by the kiln.

- Ash Grove would continue to manufacture cement (albeit at higher cost) if secondary materials no longer could be utilized. The economic viability of the plant does not depend on its use as a waste destruction unit.

Under the criteria applied by the PCHB in the City of Tacoma decision, Ash Grove/Seattle is not an "incinerator facility." Moreover, none of the secondary materials that Ash Grove consumes in its kiln, other than recycled tires, are "solid waste" within the meaning of WAC 173-434-030(3). An industrial byproduct purchased at fair market value as a raw material source is not a "waste" at all.

The design and operation standards contained in WAC 173-434-160 were designed for incinerators, not for cement kilns. Ash Grove cannot meet at least one of those standards when the raw mill is not operating. The main kiln baghouse operates with an average inlet temperature of 493 degrees F with the raw mill off, well above the 350 degree maximum temperature limit set by WAC 173-434-160(6) for the inlet to the particulate control device. This limit was established to ensure that an incinerator baghouse captures condensable toxic particulates. Response to comments on WAC ch. 173-434 at 15 (undated). Ash Grove is subject to 40 CFR 63 Subpart LLL and has conducted emission testing with the raw mill running and with the raw mill off. In both cases we have demonstrated that the kiln is an area source for the regulated hazardous air pollutants including HCl (less than 10 tons per year) and that dioxin emissions are well below the applicable standards for both conditions as well. This demonstrates that Ash Grove's kiln is a well controlled source and there is no need to subject this manufacturing process to standards other than 40 CFR 60 Subpart F and 40 CFR 63 Subpart LLL.

Ash Grove's raw mill operates whenever the kiln operates, except during planned maintenance shutdowns and unscheduled malfunctions. WAC 173-434-160 does not specify the averaging interval over which the particulate control device temperature limit must be demonstrated. If PSCAA concludes that the Seattle plant is an "incinerator facility," Ash Grove requests that the permit include a condition requiring compliance with the temperature limit over a 30 day rolling average, a time period long enough to accommodate raw mill outages.

Puget Sound Clean Air Agency Response

Comment noted. The Agency respectfully disagrees with this analysis. At Ash Grove, the practice in question is the feeding of tires to the kiln at rates greater than 12 tons per day. This practice was reviewed and approved in Notice of Construction Order of Approval No. 5755, issued on March 30, 1995. That NOC application described the tires as a fuel supplement to the kiln. Also, it is acknowledged that the draft permit erroneously identified this regulation as an "inapplicable" requirement. Further review and subsequent activities have clarified the applicability of this regulation to Ash Grove.

Ash Grove contends that WAC 173-434 should not apply because the facility was designed and operated exclusively to produce cement clinker and thus, thermal destruction of solid waste is neither a principal nor an ancillary function. In light of the decision of the Pollution Control Hearings Board (PCHB) in *City of Tacoma Department of Public Works and Tacoma Energy Recovery Co. v. Puget Sound Clean Air* Agency, Order Granting Summary Judgment (PCHB No. 02-020, June 14, 2002), the Agency does not find this argument compelling. The Agency concludes that the burning of tires, which are considered solid waste, is ancillary to the cement production process and subject to WAC 173-434.

Ash Grove also contends that the tires provide raw material benefits, specifically iron, for the cement manufacturing process. While that may be true, the NOC record for the tire feeding activity clearly identified these tires as a fuel substitution for the primary fuel (coal). Ash Grove also contends that the use of the tires as feed to the kiln is not an economic necessity and that cement production would continue without this secondary material. That does not alter the conclusion above or change the consideration of the plant operation as an “incinerator facility” when tires are being fed as a fuel substitute.

The Agency believes the recent rulemaking efforts by the Washington State Department of Ecology regarding WAC 173-434 supports the Agency’s conclusion that WAC 173-434 applies to Ash Grove. Comments on the applicability of WAC 173-434 to cement kilns were offered by Ash Grove and Lafarge during Ecology’s rulemaking effort. The outcome of that rulemaking was a provision to allow existing practices at the cement plants, specifically the use of tires and waste oil that is nonhazardous as a fuel supplement, to be excluded from the definition of solid waste under WAC 173-434. Since the regulation has an applicability threshold of 12 tons per day of solid waste incinerated, this exclusion [found in WAC 173-434-030(3)(b)] means the current practices followed by the two cement plants in Seattle do not count towards that 12 ton per day threshold, but other solid wastes proposed and approved for use as fuel supplements can count towards the 12 ton threshold total. This exclusion would not have been necessary if WAC 173-434 had been found to be inapplicable to cement plants.

Ash Grove states that the kiln operation cannot meet the temperature limit (350ºF) at the inlet to the air pollution control device, as identified in WAC 173-434-160, when the raw mill is "off" (i.e., The kiln exhaust bypasses the raw mill and goes directly to the main baghouse). Ash Grove also requests that if the rule is deemed applicable, the averaging time for this temperature parameter be defined as a 30-day rolling average to accommodate raw mill outages. It is the understanding of the Agency that normal cement plant operation at Ash Grove is conducted with the raw mill "on" (i.e. The kiln exhaust goes through the raw mill before entering the main baghouse). The operation of this plant is designed such that the raw mill is scheduled to be "off" for short periods of time (e.g. a few hours) to allow for routine maintenance activities (e.g. scheduled changes of worn raw mill grinding tires). The raw mill may also be off line for longer periods of time as a result of unforeseen upsets. The durations of these upsets depend on the specific problem encountered, but can last for hours and up to days. If the raw mill is down for an extended period of time, the cement plant will run out of feed material. The Agency agrees that an averaging period longer than an hour is appropriate for this temperature parameter, but does not have information supporting a 30 day rolling average as requested by Ash Grove. The Agency concludes that a 24-hour average value is appropriate.

To clarify the impact of this Agency’s decision that WAC 173-434 is applicable to Ash Grove, the following steps are being taken:

- Applicable provisions of WAC 173-434, as identified in the SIP approved version of this regulation (effective date 10/18/90), have been added to the operating permit.

- WAC 173-434 (effective date 1/22/04) is identified as an inapplicable requirement for Ash Grove within this permit upon EPA's incorporation of that updated regulation into the Washington SIP.
- Each of the provisions included in the permit from the previous (10/18/90) version of the regulation are labeled as inapplicable for the permit upon the EPA's incorporation of the updated regulation into the Washington SIP.

The Agency agrees with the technical and environmental benefits identified by Ash Grove regarding the use of tires as a supplemental fuel. The source has complied with the dioxin/furan emission limits under 40 CFR 63, Subpart LLL with results significantly below the standard. The use of tires for fuel support NO_X emission reductions for normal kiln operation. The decision on the applicability of WAC 173-434 is not intended to signal that this fuel substitution practice is inappropriate. The provisions added to the permit for this regulation reflect the understanding that Ash Grove can comply with all aspects of this regulation.

Action – Applicable requirements from the SIP approved version of WAC 173-434 have been added to the permit in Conditions EU 1.36 through 1.48. As described above, the inapplicability of the rule has been incorporated into the operating permit to allow automatic implementation by the source once the EPA completes the SIP revision for this regulation.

Comment 29 (by Ash Grove 4/30/03)

NSPS Recordkeeping

Condition II.D.7 of the permit, entitled "NSPS Recordkeeping," omits the 40 CFR 60.7(b) requirement to maintain records of the startup, shutdown or malfunction of NSPS "affected facilities," control equipment and continuous monitoring systems. "Affected facilities" at Ash Grove include the Subpart F kiln and the equipment subject to Subpart Y. Please revise Condition II. D. 7 as follows:

7. NSPS Recordkeeping

Ash Grove shall maintain the following information for at least two years following the date of measurements, maintenance, reports and records:

a file of all measurements recorded by the kiln COMS and by the continuous temperature monitors installed at the inlet to each coal mill baghouse;

all reports of performance tests conducted under 40 CFR Part 60 and all applicable subparts;

all reports of performance evaluations on the kiln COMS and the coal mill temperature monitors;

all reports of CMS calibration checks on the kiln COMS and the coal mill temperature monitors;

all records of adjustments and maintenance performed on the kiln COMS and the coal mill temperature monitors;

all records required by Condition II.B.9 of the permit (kiln production rate and feed rate records)

records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the kiln, coal mills, coal feeders # 1 and 2, the raw coal silo and PF bin;
records of any malfunction in a baghouse serving the kiln, coal mills, coal feeders # 1 and 2, the raw coal silo and PF bin;
records of any period during which the kiln COMS or a coal mill temperature monitor is inoperative.

[40 CFR §60.7(b) and (f) (2/12/99); 40 CFR 60.63(a) (12/14/88); 40 CFR 60.253(a) (10/17/00); WAC 173-401-615(2)(a) (10/17/02)]

Puget Sound Clean Air Agency Response

Comment noted and is consistent with a decision by EPA Region X regarding startup and shutdown records for NSPS sources (Applicability Determination Index Control No. 0300016, 4/18/02).

Action – Change made to the permit.

Comment 30 (by Ash Grove 4/30/03)

NSPS Reporting

The last sentence of Condition II.C.5 states that semi-annual NSPS reports must be filed with both PSCAA and EPA Region 10. Section VIII of the permit (Inapplicable Requirements) describes NSPS reporting requirements that do not apply because of the delegation agreement between EPA and PSCAA. These sections should be updated to reflect the broader scope of delegation described in EPA's letter of February 5, 2003 to Dennis McLerran. Please delete the last sentence of Condition II.C.5 ("The semi-annual NSPS report shall be submitted to both the Puget Sound Clean Air Agency and EPA Region 10."). In Section VIII, please revise the row labeled "40 CFR Part 60, Subpart A, NSPS reporting requirements" to read as follows:

40 CFR Part 60, Subparts A, F and Y	NSPS reporting requirements	~~The following NSPS notices and reports need be submitted only to Puget Sound Clean Air Agency, not to EPA: notification of commencement or construction or reconstruction, notification of anticipated and actual startup, notifications of any physical change to an existing facility which may increase the emission rate of any air pollutant to which an NSPS standard applies, notifications of the date upon which demonstration of the continuous emissions monitoring system performance commences in accordance with 40 CFR 60.13(c), notification of when continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5), and performance test reports. Letter of October 8, 1999 from Anita Frankel, EPA Region 10, to Mary Burg, Washington Department of Ecology.~~ NSPS notices and reports required by Subparts A, F and Y need be submitted only to Puget Sound Clean Air Agency, not to EPA. Letter of February 5, 2003 from Betty Weise, EPA Region 10 to Dennis McLerran. EPA retains responsibility for review and approval of major changes to NSPS monitoring and test methods, as described in the February 5 letter.

<u>Puget Sound Clean Air Agency Response</u>

Comment noted and it raises an issue that is confusing, depending on the document referenced. The most current NSPS delegation letter received by the Puget Sound Clean Air Agency from EPA Region 10 is dated February 5, 2003. In paragraph 4 of that letter, the EPA states *"With delegation, the PSCAA becomes the primary implementation and enforcement authority for these delegated NSPS standards. You will be the recipient of all notifications and reports and be the point of contact for questions and compliance issues. Although EPA looks to you as the lead for implementing the delegated NSPS, we retain the authority to enforce any applicable emission standard or requirement. EPA will request notifications and reports from sources, if needed."*. This statement suggests that the EPA is waiving its need to receive required notifications and reports from the sources and that it will rely on Agency files if EPA is interested in a specific source or issue.

When reviewing 40 CFR 60.4, a different conclusion might be reached. In 40 CFR 60.4(b), it states *"Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to the EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement)."* It is not clear that the modifying language in the parentheses means the delegation authority granted by an EPA region effectively eliminates the parallel document submittals discussed in 40 CFR 60.4(a) and (b).

The Agency contacted EPA Region 10 for clarification. In a discussion with Jeff Ken Knight, Manager of Federal & Delegated Air Programs Unit at EPA Region 10, it was confirmed that the delegation letter language as it relates to parallel submittals of documents was consistent with this comment and EPA policy.

Action – Change was made to the permit to reflect this comment.

<u>Comment 31 (by Port of Seattle 2/3/03)</u>

Port of Seattle requested a hearing on the permit. The letter recapped the concern about dust fallout from the Ash Grove operations and the potential for property damage and health effects from that dust. The letter also highlighted the Port's efforts to organize tenants and neighbors to elevate their interests to Ash Grove and this Agency to make progress on their concerns about dust. The letter also expressed concern about the differences in the complaint response provisions of the permit in comparison to a draft air operating permit for Lafarge reviewed earlier.

Puget Sound Clean Air Agency Response

Comment noted, yet more specific comments were submitted on April 30, 2003. Information regarding the public comment period was shared with Kay Wisner, with the understanding it would be shared with the interested group working with the Port. There was no intention to exclude the Port or anyone from commenting on the permit.

With respect to the comment regarding differences from the Lafarge document reviewed previously by the Port, the document the Port refers to was a "draft" air operating permit and has only indirect relationship to this specific permit open for review. Differences with the Lafarge draft complaint response conditions are discussed in more detail later.

Action – The comment period for the Ash Grove permit was extended through April 30, 2003 and a public hearing was held on April 1, 2003 in order to expand the public opportunity to comment on this draft permit.

Comment 32 (by Port of Seattle 4/30/03)

The following is a summary of an introductory comment in a longer comment letter:

A. Impact of Ash Grove Air Emissions on Port Property

- Port owns over 200 acres near Ash Grove, including three marinas, Terminal 104 (directly north), Terminal 106 (several buildings south and east with 11 tenants including Customs, USDA), Terminal 108 (south including Container Care), Terminal 102 (south end Harbor Island with 27 tenants, and Terminal 25 (Harbor Island cranes).
- The Port and all these businesses have complained for years about property damage and potential health concerns related from gritty corrosive dust fallout from Ash Grove. Terminal 106 roof and gutters get covered and damaged with measurable and obvious cement dust fallout. Additional total Port maintenance costs due to fallout is over $100,000 per year.
- Submitting an aerial photograph of the Ash Grove facility (about early summer 1994), showing white cement dust fallout on parking lot of Terminal 104 (north), and darken the roof of Terminal 106 (south).
- Port and other employees vehicles affected.
- Ash Grove's fallout is extremely abrasive, and damages auto paint and windshields Boats are damaged and many customers have left.
- The Port has tried to work with Ash Grove for many years (major efforts in 1995 and 2001). Some periodic progress but generally Ash Grove denies responsibility. Ash Grove motivated by fear of lawsuits, rather than sincere desire to solve problem. Ash Grove refuses to have a reliable off-site monitoring program.
- Appreciate recent equipment upgrades (required by the Agency), but afraid nuisance emissions will continue.

- The Agency needs to use its regulatory authority in the Operating Permit.

Puget Sound Clean Air Agency Response

Comment noted, though no specific permit comment or suggested permit change suggested with this comment.

Action – No changes made to permit based on this comment.

Comment 33 (by Port of Seattle 4/30/03)

B. Comments on the Ash Grove Permit

Permit Requirement: Page 5, Nuisance Standard (Requirement No. I.A.7)

The Port very much supports the inclusion of the nuisance standard in this permit. In particular, the statement that the Permittee "shall not deposit particulate matter beyond property boundary" clearly expresses the Port's long-standing position that Ash Grove must look beyond its own property line when evaluating its environmental effects.

The nuisance standard language states that monitoring for compliance will be achieved through three methods: Complaint Response, Roof-top Inspections, and O&M Plan Inspections. Unfortunately, as discussed below, these methods are insufficient to establish an enforceable monitoring program. This section should be amended to include Off-Site Monitoring requirements.

Puget Sound Clean Air Agency Response

Comment noted. Please see the responses to Comments 34 through 38 (by Port of Seattle 4/30/03) for more detailed discussion of the elements of this comment.

Action – No changes made to the permit on the basis of this comment.

Comment 34 (by Port of Seattle 4/30/03)

Permit Requirement: Page 6, Fugitive Dust Standard (Requirement No. I.A.10)

Comment: The Port supports the inclusion of this fugitive dust standard, because it sets a "zero tolerance" for fugitive dust from any equipment used in the manufacturing process or control equipment. At the hearing on this permit, Mr. Jim Nolan of the Agency stated that the permit covered the barges and trucks used to transport the raw and finished materials; therefore, we assume this fugitive dust standard also applies to that "equipment."

The fugitive dust standard language states that monitoring for compliance will be achieved through two methods: Complaint Response and Roof-top Inspections. This section should be amended to include Off-Site Monitoring requirements. (It is not clear why O&M Plan Inspections should not also be a compliance method – the agency should consider amending this section to include those inspections as well).

Puget Sound Clean Air Agency Response

Comment noted but it is not clear if the draft version available to the public was used for this comment. Condition I.A.10 is part of the currently SIP approved version of the fugitive dust regulation and it does identify both Roof Top Inspections (Condition II.A.3) and O&M Plan Inspections (Condition II.A.4) as the required monitoring provisions which have been identified for this applicable requirement.

The comment that this requirement creates a "zero tolerance" for fugitive emissions is inaccurate with respect to both the previously SIP approved version of Puget Sound Clean Air Agency Regulation I, Section 9.15 and the currently implemented version of this regulation as found in the most recent Puget Sound Clean Air Agency regulations (see Condition I.A.13 of the permit). When the EPA approves the latest version of Regulation I, Section 9.15 into the Washington SIP, Condition I.A.13 of the permit will be the only Puget Sound Clean Air Agency requirement for fugitive dust that will be effective in the Ash Grove permit. At that point, Conditions I.A.9, I.A.10, and I.A.12 will be superceded and no longer in effect for this permit. Action by EPA on the update to the Puget Sound Clean Air Agency portion of the Washington SIP is expected to occur soon.

The compliance and project history for Ash Grove indicates that fugitive dust problems which have been identified have been corrected through improvements in equipment and operational practices. When fugitive dust is released from some piece of equipment that is normally contained, it is most often due to an upset and Ash Grove should respond to the condition appropriately, including efforts to minimize and reduce releases. The Agency believes the permit and the various plans implemented by Ash Grove will support that response.

Action – No change to the permit made based on this comment.

Comment 35 (by Port of Seattle 4/30/03)

Permit Requirement: Page 31, Roof-top Inspections (Part II (A)(3))

Comment: Rooftop inspections are an amazingly crude and subjective way to measure an enforceable air quality requirement. As I understand it, this requirement basically consists of a company employee climbing up on the roof and peering around. The problems with such an approach are obvious. First, the inspection is limited to only that property contained within the facility boundaries (see footnote 1). Thus, on its face it fails to be a reliable indicator of compliance with the off-property nuisance standard. Second, the requirement does not specify when the inspection must take place. As the Agency knows very well, Ash Grove's harmful emissions are extremely dependent on such factors as plant operations and weather conditions. Ash Grove can simply select a time for its inspection when everything is working perfectly. Third, the emissions may not be visible to the naked eye, but can still be harmful when they accumulate over time.

At a minimum, the Agency should require that the inspections happen at certain times, for example during upset conditions, or within one hour after a complaint is received, or every other Wednesday. In no event should the inspection take place when the facility is not operating.

Puget Sound Clean Air Agency Response

Comment noted. This monitoring is the same requirement used in several Title V permits for large sources. As a result of Title V, sources must now do significantly more monitoring and record keeping. Since the operating permit requires roof top monitoring in conjunction with general O&M inspections, plant-wide opacity monitoring, inspection for track out, and a complaint response program, significant efforts will be implemented to identify and respond to potentially problematic conditions within the plant. Each of these efforts, along with the ongoing Agency inspections, is believed to reasonably assure continuous compliance. Inspections are written for plant activities within the Ash Grove site since that is the scope of the permit and represents the operations and emissions for which Ash Grove is directly responsible.

Additionally, upsets or operational problems which could cause problem impacts offsite should be dealt with in a preventative and/or timely response at the source to correct the problem or minimize its impact. The compliance history documented for the site indicates that effective equipment operation and timely maintenance provide the most responsive corrective actions to problems.

The permit directly states in Condition II.A.1 that the observations must be made when the equipment is operating. Ash Grove will determine the specific schedule for required observations and it must meet the frequency and informational requirements specified by this permit. With regard to conducting scheduled observations during upsets or following complaints, it is the expectation of this Agency that Ash Grove will be responding to an upset to correct the problem or that it will be investigating the complaint once it is received, rather than scheduling routine compliance monitoring observations. Complaint response activities will be included in the monthly reports required by the permit anyway [see Comment 45 (Port of Seattle 4/30/03)].

Action – No change made to the permit based on this comment.

Comment 36 (by Port of Seattle 4/30/03)

Permit Requirement: Page 31, O&M Plan Inspections (Part II (A)(4))

Comment: This is the second "monitoring method" that is intended to determine whether nuisance emissions have occurred. However, the sole purpose of this inspection method is to make sure that the equipment is working correctly. Obviously, the equipment that is in place is not adequate to prevent nuisances, or there wouldn't be continuing complaints. Thus, although it is certainly a good idea to make sure the equipment is working, this is an insufficient measure of compliance success in the case of the nuisance standard.

Puget Sound Clean Air Agency Response

Comment noted. The O&M plan inspection requirement identified in the draft permit covers both the operation of equipment and other activities associated with potential fugitive dust emissions. The compliance history discussed in the draft statement of basis indicated that many of the fugitive dust violations (cited as either fugitive dust or nuisance violations) for the plant resulted from equipment not being operated correctly. In some of those enforcement cases, additional equipment or equipment improvements or improved O & M procedures were part of the resolution. At the present time, the Agency believes that the equipment onsite is adequately designed and that compliance will be maintained through a commitment from Ash Grove to effectively follow their O&M plan.

Action – No change made to the permit based on this comment.

Comment 37 (by Port of Seattle 4/30/03)

Permit Requirement: None

Comment: As should be clear from the above discussion, what is missing from the permit is a reliable, non-subjective measurement of non-compliance with the nuisance standard. In other words, what is missing is an Off-site Monitoring Program for both fugitive dust and nuisance emissions.

It is our understanding that the Draft Permit does not include such an off-site monitoring program because the existing state and federal rules do not establish a standardized testing method. However, we encourage the Agency to view this as an opportunity to exert leadership, not as an insurmountable hurdle. We believe strongly that what is needed at this point is an independent research program to answer the question, to the extent possible, of what is source of deposition on neighboring properties. This research program should be headed by the Agency, but should involve the participation of affected neighbors, to assure that the outcome is acceptable to all parties.

We propose that the following language be added to Part II.A.

II.A.6 Off-Site Monitoring Program

Within 90 days of the permit effective date, Ash Grove shall submit its plan for an Off-Site Monitoring Program to measure the quality and quantity of fugitive dust emissions and nuisance emissions on adjacent properties. At a minimum, the plan will describe the sampling locations, sampling frequency and duration, quality assurance and analytical methods, and reporting formats to be used. Sampling events shall be spread adequately to account for seasonal variations. There must be adequate number of samples collected to ensure statistical significance.

Puget Sound Clean Air Agency Response

Comment noted and the Agency disagrees with the technical and regulatory premise of this request. Although there is an old Washington Department of Ecology fallout standard that was promulgated prior to the federal EPA program for ambient standards, there is currently no approved state method for sampling. This old fallout standard was supplanted by the current federally supported suspended particulate ambient standards.

The ambient air in the vicinity of the Ash Grove plant is a shared resource and any measured pollutant concentrations which are observed from any ambient monitoring technique would reflect the impacts of Ash Grove, Port operations, operations by Port tenant business, and others beyond the immediate vicinity. Even if such a requirement was appropriate, the Agency is not aware of any reasonably available monitoring technology and strategy which will answer the question posed by the Port.

There are no outstanding violations which would support a compliance plan to be attached to this permit. The level and frequency of monitoring identified in the permit is based on the compliance history and potential for violations.

Action – No change made to the permit based on this comment.

Comment 38 (by Port of Seattle 4/30/03)

The Agency, in conjunction with affected property owners selected by the Agency (hereafter, the "Off-Site Monitoring Program Taskforce") shall review and comment on the draft proposal. Ash Grove shall incorporate all reasonable comments made by the Taskforce. The Agency shall determine what is reasonable.

Within 30 days after the plan for the Off-Site Monitoring Program has been finalized, Ash Grove will begin conducting the prescribed monitoring.

After one year of monitoring, the Agency and the Taskforce will reconvene to review the results. At that time, the Agency may request changes to the Off-Site Monitoring Plan. These changes shall be incorporated, and a new version of the plan developed and implemented. Monitoring under the revised protocol shall then continue for one additional year.

Within 60 days after the cessation of monitoring, the Permittee shall submit a final report to the Agency. The final report shall summarize the results of the monitoring and identify the likely sources of fugitive dust or other air contaminants impacting neighboring properties.

Alternately, the last paragraph (reporting requirements) could be put into Part II(C).

Puget Sound Clean Air Agency Response

Comment noted. Please see response to Comment 37 above, regarding offsite monitoring as an element of an air operating permit. Additionally, the concept of establishing a task force through air operating permit conditions is inconsistent with the relevant regulations. The permit must identify all applicable air regulatory requirements and identify the monitoring, recordkeeping, and reporting necessary to reasonably assure continuous compliance by the source. The Agency believes the permit conditions should focus on plant operations rather than offsite impacts.

Action – No change made to the permit based on this comment.

Comment 39 (by Port of Seattle 4/30/03)

Permit Requirement: Page 30, Complaint Response, Third Bullet (Part II.A(2))

Comment: As an initial matter, many aspects of this Compliant Response section are positive, and we are hopeful that including them as permit requirements will create consistency and accountability in what has, up to now, been a purely voluntary effort on the part of Ash Grove.

We would like to comment on the third bullet ("criteria and methods for establishing whether Ash Grove may be the source of fugitive dust.") As discussed above, the Port is unconvinced of the wisdom of having Ash Grove itself determine what should be the criteria. We respectfully suggest that the final report of the Off-Site Monitoring Program (discussed above) be used to establish this. Although this approach has the disadvantage of postponing for several years the establishment of these criteria, it has the benefit that the eventual outcome will be acceptable to all, rather than a source of continuing disagreement and controversy.

Puget Sound Clean Air Agency Response

Comment noted. Please see Comment 41 for a response to the comment on the Complaint Response provisions of the permit. Please see Comment 37 and 38 for a response to the proposed offsite monitoring program comment.

Action – No changes made to the permit based on this comment.

Comment 40 (by Port of Seattle 4/30/03)

Permit Requirement: Complaint Response, Missing bullet

Comment: The Complaint Response section in the

Lafarge permit states that the Complaint Response Program must include an element for "actions for addressing complaints and their causes." The deletion of this element from the Ash Grove permit lets them off the hook completely. Without it, Ash Grove need only record and investigate complaints -- they never have to DO anything about it. This is a very, very significant omission and should be corrected.

Puget Sound Clean Air Agency Response

Comment noted and the Agency disagrees with the comment. The language in Condition II.D.6(d) requires a record of the investigation efforts and basis for conclusions reached on that complaint. Condition II.D.6(e) requires a record of any corrective action taken as a response to a complaint. Please see response to Comment 43 (by Port of Seattle 4/30/03) for more discussion.

Action – No changes made to the permit based on this comment.

Comment 41 (by Port of Seattle 4/30/03)

Permit Requirement: Page 30, Complaint Response, Fifth bullet (Part II.A(2))

Comment: The fourth bullet requires that "investigations shall be initiated within 3 working days." This should be changed to read "conducted within 3 working days." In addition, a parallel change would need to be made to the last sentence on page 30.

This suggested change is the language in the Lafarge permit, and there is no reason why Ash Grove should be allowed a more lenient standard (in fact, just the opposite). Complaining persons should not have to wait 3 days to get an initial response from the company.

Puget Sound Clean Air Agency Response

Comment noted and the Agency agrees with the comment in general. The Agency disagrees with the premise that an investigation should be completed within 3 working days because some investigation activities cannot be completed within that period of time. For example, if samples were collected for analysis, results may not be available within that period of time. Additional information from other entities may be requested but not available within that time frame.

In response to this comment, the Agency is revising the complaint response provisions of the permit to require an investigation be initiated within 1 day of receipt of the complaint [see Comment 45 (by Port of Seattle 4/30/03) for revised Condition II.A.2 language]. The permit originally used the term working day, but it is not clear that the word "working" is needed. If the plant is running on a weekend, the Agency would consider that a working day for Ash Grove and the complaint response program should provide the ability for Ash Grove to receive complaints on those days and begin an investigation and/or response as appropriate. Ash Grove's complaint response plan can more specifically define "receipt" of complaints and its initial steps to "investigate" the complaint.

The Agency acknowledges the concerns expressed by Ash Grove regarding the ability to determine whether each complaint is attributable to Ash Grove since it has no control over the timeliness or level of detail they receive in a complaint [see Comment 16 (by Ash Grove 1/31/03]. It is useful for all citizens that will use the complaint response provisions described in this permit to remember that the timeliness and level of detail provided with the complaint will enhance the ability of Ash Grove to investigate and respond in an appropriate manner. At the same time, it is the responsibility of Ash Grove to identify for the complainants what types of information they would like to receive which will make their investigation and response more productive.

Action – Change made to the permit as discussed above.

Comment 42 (by Port of Seattle 4/30/03)

Permit Requirement: Page 30, Complaint Response, Fifth Bullet (Part II.A(2))

Comment: The Lafarge permit also contains certain criteria for when investigations should be initiated, which have been deleted from the Ash Grove permit. These should be reinstated. Please insert the following language at the end of the fifth bullet:

Investigations shall include potential sources within Ash Grove's facility, considering the following circumstances:

1) Emissions that are, or likely to be, injurious to human health, plant or animal life, or property, or which unreasonably interfere with enjoyment of life and property;

2) Fugitive dust emissions or evidence of inadequate fugitive dust control measures;

3) Evidence of fallout materials and any physical or chemical associations with plant-site activities;

4) Materials tracked onto paved roads open to the public;

5) Emissions of odor-bearing air contaminants;

6) Equipment operating in such a manner as can reasonably be expected to contribute to emissions that can result in fallout complaints;

7) Emissions due to startup, shutdown, malfunction or emergencies as defined in WAC 173-400-107 or WAC 173-401-645;

8) Emissions caused by non-compliance with applicable requirements of this permit; and

9) Any complaints relating to other applicable requirements of this permit.

Puget Sound Clean Air Agency Response

Comment noted. The elements of a complaint response program are different from the draft Lafarge document yet not in significant ways [see Comment 31 (by Port of Seattle 4/30/03) regarding the relationship between a draft permit for Lafarge and a draft permit for Ash Grove]. It is important to consider the entire complaint response provisions included in the Ash Grove permit. Conditions II.A.2, II.C.10, and II.D.6 represent the monitoring, reporting, and recordkeeping provisions of the complaint response efforts, respectively. The draft Ash Grove permit had less prescriptive language regarding the elements of an investigation than identified in the draft Lafarge document, but the program Ash Grove must develop for compliance with this permit has to identify the criteria and methods used to establish whether Ash Grove may be the source of fugitive dust or other air contaminant impacts on neighboring property. The program is a part of the O&M plans for the facility and must be reviewed and updated annually. Failure to follow the program as identified in the program included in the O&M plans for the facility will be considered a deviation from the permit. The elements of all three conditions included in the permit for complaint response reflect that fact.

There are three reasons for a less rigid or prescriptive description of the scope of investigation in response to a complaint:

- The complaint response plan needs to respond to all air quality related complaints and can not presume in advance the full range of complaints that may be received. The program needs to be broad enough and flexible enough to deal with unexpected complaints.
- If some aspect of Ash Grove's complaint response program were deemed inadequate based on a review of the complaint response records or other information available to the Agency or the public, feedback to Ash Grove could address the adequacy and possible need to update the program.
- When the program is updated in the future, it is desirable to have it be done without necessitating an operating permit modification. Including more specific language in a permit may lead to more permit modifications.

In the Ash Grove permit documents, an investigation is required for every complaint. The adequacy of the investigations will be available for review based on the records kept and the reports that must be submitted regularly.

Action – No changes made to the permit on the basis of this comment.

Comment 43 (by Port of Seattle 4/30/03)

Permit Requirement: Page 30, Complaint Response, Last paragraph

Comment: This paragraph states that "[i]f Ash Grove determines that emissions from its plant unreasonably impacted neighborhood properties…." On the other hand, the Lafarge permit simply states that "[i]f Lafarge identifies its plant as the source contributing to air pollution complaints …." This is a very significant difference. For one thing, the use of the word "unreasonable" is subjective – how can Ash Grove determine whether someone else is being "unreasonably impacted"? Moreover, the Lafarge language only requires that Lafarge "contribute" to the complaints, while Ash Grove's language could be interpreted to require a more direct cause/effect relationship. We suggest you substitute the Lafarge language. An alternate idea is to have the Taskforce tasked with coming up with criteria/triggers for what is "unreasonable."

Puget Sound Clean Air Agency Response

Comment noted – please see Comment 42 (by Port of Seattle 4/30/03) response for discussion of the relationship between the draft Lafarge operating permit and the draft Ash Grove operating permit.

This comment implies that most complaint communication to Ash Grove and response by Ash Grove to that complaint is a real time phenomenon. The history with the facility indicates that this is rarely the case and Ash Grove must determine if it is possible or probable that a complaint relates to its plant operation.

The complaint response program, as revised based on comments to the draft permit, provides adequate checks and balances. The three conditions which address this program (Conditions II.A.2, II.C.10, and II.D.6) will provide the following information:

- For each complaint, what investigation efforts were made and what is the basis for the conclusion reached by Ash Grove? [Condition II.D.6 (d)]
- For each complaint, what corrective action (if any) was taken? [Condition II.D.6(e)]

The records maintained by Ash Grove under this program allow the review of the record relating to all complaints. This information may also trigger other actions and responses under Conditions II.A.3, II.A.4, and II.A.5 of the permit.

Another aspect of the program which is open to review is the complaint response timeliness. If someone files a complaint with the plant indicating that a nuisance related event is occurring at the time of the complaint and the plant waits for 1 day to begin its investigation (as the revised permit conditions allow), then it will be difficult for Ash Grove to claim a time lapse as a contributing factor to the inability to reach a determination of its role (if any) in the complaint.

Action – No changes made to the permit based on this comment. However, please see Comment 45 (by Port of Seattle 4/30/03) for revisions to the complaint response program elements as a result of other comments.

Comment 44 (by Port of Seattle 4/30/03)

Permit Requirement: Page 30, Complaint Response, Last paragraph

Comment: This paragraph requires that Ash Grove "eliminate the problem" within 24 hours. This seems to be not quite reasonable when the "problem" is a complaint, and may create a disincentive to taking appropriate action. The company should also have the option of taking other corrective action, even if the result is not the "elimination" of the problem, or it doesn't happen within 24 hours. For example, a positive solution might be for them to clean our parking lot, even though that doesn't eliminate the problem, but simply temporarily mitigates a symptom. We suggest the following change:

Ash Grove shall either:

1) eliminate the problem within 24 hours of identification ~~or~~

2) report a deviation…., or

3) within 3 days of identification, obtain written agreement to an alternate course of action from the complaining party, and subsequently implement that course of action.

Puget Sound Clean Air Agency Response

Comment noted. Please see response to Comments 42 and 43 (Port of Seattle, 4/30/03) for related responses.

Note – the suggested language would not be appropriate for an operating permit. If Ash Grove needs to correct a problem within 24 hours, then it either needs to correct the problem or report a deviation and explain why it did not meet that requirement. The comment suggesting a third party may negotiate a compliance agreement with the source is not acceptable to this Agency as an appropriate response to permit deviations.

Action – No change made to the permit based on this comment.

Comment 45 (by Port of Seattle 4/30/03)

Permit Requirement: Page 41, Complaint Response Reporting (Part II.C (10))

Comment: For completeness, this requirement should be re-written as follows:

Ash Grove shall submit in writing …a report documenting

1) complaints received that are determined not to be attributable to Ash Grove operations;

2) complaints received that are determined to be attributable to Ash Grove operations that trigger corrective action; and

3) complaints received that ~~as well as those~~ that are determined to be attributable to Ash Grove operations that did not trigger corrective action.

Puget Sound Clean Air Agency Response

Comment noted and the Agency agrees that a more complete Complaint Response Report is appropriate for this permit. A monthly report identifying all complaints received will be required in the final permit.

Action – Change made to the permit as discussed above. See revised conditions (Conditions II.A.2 and II.C.10) of the permit relating to complaint response below.

II.A.2 Complaint Response

Ash Grove shall develop and implement an Air Pollution Complaint Response Program as part of the O&M Plan required by Regulation I Section 7.09(b). The Complaint Response Program shall be annually reviewed and updated along with the O&M Plan. This Program shall include:

- An Ash Grove local contact person and a 24-hour telephone number;
- Complaint forms available to the public;
- Criteria and methods for establishing whether Ash Grove may be the source of fugitive dust or other air contaminant impacts on neighboring property;
- Format of communicating results of investigations and advising complainants of Ash Grove's corrective actions and preventive maintenance;
- Ash Grove shall record air pollution complaints (including those forwarded to Ash Grove from this Agency) and findings of investigations as provided in Condition II.D.6. Investigations shall be initiated within 1 ~~3 working~~ day~~s~~ of receipt of a complaint. Complaint investigations shall include efforts to contact the complainant, to inspect the conditions described in the complaint, to determine whether the Seattle plant sustained a malfunction or other operating or site conditions that might have generated abnormal levels of fugitive emissions, and to determine the wind speed, direction and/or other meteorological conditions during relevant times preceding receipt of the complaint.

If Ash Grove determines that emissions from its plant unreasonably impacted neighboring properties Ash Grove shall either eliminate the problem within 24 hours of identification or report a deviation as provided in Condition II.C.2. Ash Grove also shall report as a deviation any failure to initiate investigation of a complaint within 1 ~~3 working~~ day~~s~~ of receipt of the complaint.

[WAC 173-401-615(1), 10/17/02]

II.C.10 Complaint Response Reporting

Ash Grove shall submit in writing to Puget Sound Clean Air Agency a report documenting all complaints received with a summary of the nature of the complaint, the conclusion of the investigation, and any corrective action taken in response. ~~that are determined not to be attributable to Ash Grove operations as well as those that are determined to be attributable to Ash Grove operations yet did not trigger corrective action.~~ This report shall be submitted no later than 30 days after the end of the month during which this condition occurred. In the event there are no reportable events, Ash Grove shall include a statement to that effect, as identified in Section II.C.1 of this permit.

[WAC 173-401-615(3) (10/17/02)]

II.D.6 Complaint Response Recordkeeping

Records for complaints received concerning odor, fugitive emissions or nuisance conditions must contain the following information:

a) Date and time of the complaint,

b) Name and address of the person complaining, if known,

c) Nature of the complaint,

d) Investigation efforts and the basis for conclusions reached regarding the complaint, and

e) Date, time and nature of any corrective action taken.

[Puget Sound Clean Air Agency Regulation I, Section 7.09(b)(6), (10/6/97)] [Puget Sound Clean Air Agency Regulation I, Section 7.09(b)(6), 9/10/98, (State Only)] [WAC 173-401-615(2)(a) (10/17/02)]

Comment 46 (by Dave & Erin Simkus 3/25/03)

Dave and Erin Simkus

March 25, 2003

- Boat owner at Harbor Island Marina.
- Requests off-site boat and rooftop inspections by independent third party.
- Include barges and unloading in I.A.I0 on page 6.
- Cover conveyers from barges.
- Have Task Force set criteria for source of fugitive dust.
- Task Force include Ash Grove, Lafarge and neighbors.
- Ash Grove should not be allowed to define "unreasonably" on page 307.
- Remove "unreasonably", it is too vague, if impacting neighbors it's a problem.

Puget Sound Clean Air Agency Response

Comments noted and are similar to comments made by the Port of Seattle (4/30/03).

Action – Please see responses to Comments 32 through 45 (by Port of Seattle 4/30/03) and the changes made to the permit based on those comments.

Comment 47 (by Lee & Dan Rees 4/9/03)

LEE & DAN REES

April 9, 2003

- Written comments not at public hearing.
- Boat owners at Harbor Island Marina.
- Ash Grove's cement dust has increased over last ten years.
- Complained to Ash Grove and Agency.
- The most severe discharges are periodic and leave a residue that is extremely difficult to clean off of fiberglass boats. "Grit" jams wenches and instruments, and can not rinse off but must scrub with chemical cleaners. Cleaners removes wax finish. Dust discolors and eats decks.
- Ash Grove claims dust is not from their plant. Sample analysis takes 3-4 weeks
- Nuisance Standards in I.A.7 is wholly insufficient.
- Need following:
    - Require three continuous monitors near marina to detect discharges.
    - Streamline timely tests for fingerprinting residue and source in plant.
    - Ash Grove fix damages due to their discharges.

Puget Sound Clean Air Agency Response

Comments noted and are similar to comments made by the Port of Seattle (4/30/03). Note – in the past investigations conducted by inspectors from this Agency when samples were collected, the important time element was not sample turnaround for results but the proximity to the release event which created a deposit for sampling (i.e. Is the sample fresh?).

Action – Please see responses to Comments 32 through 45 (by Port of Seattle 4/30/03) and the changes made to the permit based on those comments.

Comment 48 (by Bruce Andre, Ponchos'Legacy LLC 4/30/03)

The following is a summary of written comments provided by Mr. Andre:

- Since hearing two major kiln upsets causing clinker dust on our property.
- Reported to PSCAA and Ash Grove.
- 4/2/03 kiln upset, blew hot ash with south wind. Videoed event. Jerry Brown offered car cleaning. Ash Grove estimates 30-days to pay.
- 4/13/03 kiln upset, not turning 4/14/03. Lots of clinker dust on our roof. Jerry Brown said lost kiln "ID Fan". Videoed April 14th. He inspected our roof, took samples and asked what they could do for us. Our roofer is meeting with Jerry Brown for an acceptable cleaning method. Jerry said water spraying of kiln for operational reasons, not for suppression of fugitive dust. Water was turned off after event.
- 4/29/03 complaint to Agency of odor from Ash Grove. The wind changed to south blowing directly from Ash Grove. Complainant felt that this specific complaint was incorrectly being grouped with complaints focused on Lafarge.

Puget Sound Clean Air Agency Response

Comment noted, though these comments are not specific to the permit or changes suggested to the permit. The comment with respect to possible misclassification of complaints is acknowledged. No specific enforcement action was taken by the Agency with respect to the events Mr. Andre discusses.

Action – No changes made to the permit based on this comment.

Comment 49 (by Bruce Andre, Ponchos' Legacy LLC 4/30/03)

The following is a summary of written comments provided by Mr. Andre:

- Owner of Legacy, employee of International Belt & Rubber Supply Inc, north of Ash Grove. Has a great deal of personal knowledge and understanding of Ash Grove. International Belt and Rubber did not complain about fallout because of contracts. Requested Ash Grove clean roof after Port had their roof cleaned
- Provides details of historical fallout problems from his perspective.
- Legacy cleaned clinker off roof 8/16/02 and complained to Ash Grove.
- Ponchos' Legacy damaged their roof while trying to clean it.
- Legacy invoiced Ash Grove for roof repairs ($5,500) and Ash Grove stopped contracts Legacy (~$300,000/year).
- Chronological records of correspondence and actions:

- 10/2/89 Ash Grove paid Elliot Bay Investments $6,616 for roof repairs without liability.
- 2/9/94 Ash Grove mitigated impacts to John Harvey's roof.
- 9/19/95 Agency describes Port samples that CTL found clinker.
- 7/17/96 Ash Grove's corrective action included;
    - Enclosing 531.030 conveyor with plastic wrap,
    - Enclosing 471.170 conveyor with plastic wrap, and
    - Designing kiln leaf seals.
    - Ash Grove reiterates efforts to be a "good neighbor."
- 8/30/96 EPA to Port indicates enforcement is PSCAA's.
- 10/7/96 Thomas Newlon (senior Port counsel) dissatisfied with Agency's actions to solve fallout problem.
- 4/18/97 Thomas Newlon to Ash Grove's attorney, asks for mitigation.
- 11/20/97 Ash Grove to Newlon for settlement without admitting liability.
- 11/21/97 Ash Grove's mitigation process for Port employees.
- 6/6/98 Legacy buys building.
- 9/21/99 CTL finds Portland cement clinker, cement and fly ash.
- 11/30/99 CTL XRD confirms Sept 21, 1999 results.
- 2/13/99 Process Analysis Corp. says it doesn't "look" like clinker.
- 2/13/01 Agency's fallout procedures with Ash Grove's corrective actions.
- 6/10/02 Ash Grove's reporting procedures and cleaning of affected neighbors.
- 6/26/02 Port to tenants and neighbors of Ash Grove's 6/10/02 actions.
- 8/16/02 Complained to Agency of dust from Ash Grove.
- 8/20/02 Ash Grove cuts business with Belt and Rubber.

- Major areas causing fugitive dust problems and suggested improvements:
    - <u>Barge Unloading Conveyors</u>. Re-engineer and enclose with suppression measures.
    - <u>Limestone/Coal piles and Conveyors</u>. Enclose "storage shed".
    - <u>Raw Products Reclaim System.</u> Enclose.
    - <u>Kiln Cooler Elbows and Tubes</u>. Boltless liners and water on kiln not enough. Put roof over burner end of kiln to stop clinker from blowing into the air. Since last start up, smelled chlorine from Ash Grove with south winds which causes me a head ache. Other employee's have also smelled this odor.
    - <u>Kiln Discharge End and G-Cooler.</u> Continue to discharge clinker. What is status of kiln leaf seals? Grate cooler system has been investigated which may control some fugitive dust.
    - <u>New Clinker Storage Silo Baghouses.</u> Access doors are often left open.
    - <u>Conveyor 531. 030</u>. Completed.
    - <u>Finish Mill Building</u>. Blows dust and needs new dust control system.
    - <u>Conveyor Clinker Silos to Clinker Shed</u>. Completely enclose.
    - <u>Clinker Storage Shed</u>. Needs new dust collector.
    - <u>Clinker Storage Shed Reclaim Elevator</u>. Visible dust needs enclosing..
    - <u>Baghouse by Maintenance Shop.</u> Fugitive dust during normal during maintenance.
    - <u>Air Slides & Ducting top of Load Out Silos.</u> Leaks per 1994 video.
    - <u>Dome Storage Silo</u>. Leaks, need to close doors.

    - Finish Mill, Clinker Storage silos and Clinker Storage Shed. All have asbestos siding with no protective coating or encapsulation. It is deteriorating and being damaged by employees or sub-contractors, causing airborne uncontained asbestos fibers. Please coat it or remove it!
    - Dome Storage Silo. Creates wind funnel increasing fallout on our property.
- Ash Grove's monitoring is flawed and doesn't address neighbor's property damage.
- Monitoring should be half-mile beyond property boundary, by affected.
- Monitor monthly and after each upset.
- Title V permit should be renewed annually.
- Request Ash Grove implement these solutions and pay damages to roofs, windows, awnings, HVAC systems, automobiles and inventories of tenants. Total damage cost at Legacy and International Belt $100,000, not including health issues. Our pictures show about 16 yards of dust removed before refinishing our roof.

Puget Sound Clean Air Agency Response

The comments are noted and the Agency appreciates the effort of Mr. Andre to document in writing the comments offered at the hearing on this draft permit on April 1, 2003.

The comments regarding the compliance issues identified in this letter are consistent with the compliance history provided in the draft statement of basis for this permit. Historically, there have been issues which were resolved through enforcement action. Some of that enforcement action has led to equipment and operational practice improvements. The efforts by Ash Grove to improve its operation and minimize its impacts on neighboring property have resulted in fewer complaints and enforcement actions.

The operating permit cannot address financial interests related to the assertion of damages caused by Ash Grove.

This list of suggested projects which would improve fugitive dust emission control is appreciated and may be useful in the future. However, the ability to order equipment modifications or upgrades normally occurs as part of the resolution of enforcement actions. There are presently no outstanding enforcement actions against Ash Grove with respect to fugitive dust or nuisance regulations.

With respect to the permit monitoring provisions, please see the responses to Comments 32 through 45 (by Port of Seattle 4/30/03) which address the same comments raised here.

Also, air operating permits are renewable on a 5-year frequency, as specified in WAC 173-401.

Action – No changes made to the permit based on these comments.

Hearing Comments

Summary

The public hearing to receive comments on the draft air operating permit for Ash Grove was held on April 1, 2003. Comments made (using notes taken during the hearing) are provided below to identify the speaker and show the nature of their comments.

The comments at the hearing reflect the written comments received on the permit. This is expected since many of the speakers at the hearing also submitted comments in writing. The comments at the hearing can be summarized as follows:

Ash Grove is committed to being a good neighbor, acknowledged that mistakes had been made in the past, but believes they have invested in equipment and time to provide real improvements in performance, and hopes to be able to effectively work with their neighbors in the future.

The Port of Seattle staff and neighbors near the Ash Grove plant feel that:

- The fugitive dust and other emissions from the plant are a nuisance and are causing property damage.

- The permit should be more aggressive to require offsite monitoring as an element of compliance demonstration.
- A task force should be initiated to guide monitoring and response to complaint efforts and attempt to put objective criteria in place to resolve subjective standard language disputes.
- The complaint response program included in the permit should be more rigorous and prescriptive regarding requirements for Ash Grove to respond.
- There is some uneasiness regarding the judgment and decisions which rest with Ash Grove under an operating permit.
- Some felt that things had improved, but they were tired of having to contact Ash Grove to alert them of a problem or to get action. They would prefer there were no problems or impacts and when that is not possible, they would prefer that Ash Grove be more proactive.

The Agency responses developed to the written comments on the draft permit address all of these hearing comments. The response record for those written comments should be used to determine what changes were made to the permit in response to comments.

One commenter at the hearing (Dana Stall, Port of Seattle) referred to possible health effects related to emissions and releases from Ash Grove. It is important to note that the area in the vicinity of the Ash Grove plant meets all ambient air quality standards for criteria pollutants. These standards, established by EPA, are established on the basis of being protective of human health. The commenter further mentioned toxic air contaminants and the burning of tires. This is discussed in some detail in the response to Comment 28 (by Ash Grove 4/30/03). The Notice of Construction review for the proposal to burn tires in the kiln reviewed the impacts from increases in toxic air contaminants associated with that activity and those impacts were all below the Acceptable Source Impact Levels (ASILs) identified in Puget Sound Clean Air Agency Regulation III.

Gerry Brown

- Ash Grove appreciated willingness of community to work with Ash Grove.
- Spent a great deal of money upgrading plant.
- Improved communication with neighborhood.
- Notification process of neighbors when events occur.
- Spent $4 million to control dust.
- Complaint response (24 hr & phone #).
- Ash Grove responds within 24 hrs.
- Ash Grove works with neighbors and responds to damage complaints.
- There have been resolutions of a number of complaints to Agency.
- There has been a reduction in the number of complaints.
- There are monitoring requirements and complaint response procedures in permit

Serin Simkus

- There is tons of materials from barge during unloading (not addressed in plan).
- Requests including offsite monitoring of boats & surrounding roof tops.
- Include criteria to define sources of dust.
- He suggested an independent party to conduct offsite monitoring.

- He said we are all partners on the river.
- Clinker dust has ruined canvas & finishes on boats.
- Clinker fallout problems have improved but coal & limestone handling still remain a problem.
- He wants to have it controlled.

Bruce Andre

- His site is just north of Ash Grove at 3685 Duwamish Ave S. and since 1998 has been Ponchos' Legacy.
- He understands the cement industry.
- His building has a 44,000 ft^2 warehouse roof.
- Ash Grove agreed to dispose of debris.
- He wants Ash Grove to pay for cleaning after the end of the relationship between Ash Grove and International Belt & Rubber.
- He lists the chronology of correspondence.
- Ash Grove no longer does business with International Belt & Rubber.
- He described the following from West to East -
  - The barge unloading & conveyors, limestone & coal stockpiles all should be in storage shed.
  - The sources of dust include limestone reclaim area, raw material reclaim area, raw mill, kiln cooler elbows, and kiln cooler tubes.
  - There needs to be roof over kiln
- He said that recently he has smelled chlorine from Ash Grove.
- He has witnessed the following:
  - Discharge from kiln G-cooler (grate cooler),
  - Major improvements,
  - Clinker storage silo (need to close doors),
  - Old dust control system,
  - Clinker storage shed needs a baghouse,
  - Reclaim elevators and leaks in air slides
- Other things include:
  - Asbestos siding on buildings (need to coat asbestos siding panels);
  - Monitor monthly;
  - Title V should be renewed annually;
  - Information should be free of charge;
  - Compensate neighbor for damage; and
  - No retaliation against International Belt & Rubber

Susan Ridgley

- Will provide written comments for POS (Port of Seattle) Property location around Ash Grove Cement
- POS is the largest land owner with 200 acres.
- POS has been aware of impacts of Ash Grove for some time.
- There has been damage to cars & boats and other sensitive surfaces.
- Damage to POS property includes roof tops and gutter systems.
- There has been $100,000 per year as routine costs to maintain POS properties

- Ash Grove has used a lot of words but little action.
- The complaint response tracking system is okay.
- The clinker fallout is getting better but it is difficult to keep the pressure on Ash Grove all the time.
- Permit related comments:
  - Page 5 I.A.7 Nuisance standard 173-400-040 (No deposition beyond property boundary);
  - Page 31 2A Monitoring Roof top, and O&M;
  - If just a visual standard it is too crude and subjective;
  - The discussion of O&M plan is not adequate;
  - There needs to be offsite monitoring for dust and clinker;
  - Maybe there should be the use of a task force made from the neighbors and others, to answer where dust originates, monitor locations and provide reporting.
  - What is the source of the dust?
  - The complaint response has significant deviations from Lafarge.
  - Dusting problems appear to solely from within Ash Grove.
  - There needs to be criteria and the description of methods.
  - The response needs to be conducted within 3-days
  - The concept of "Unreasonably" is too subjective.
  - What triggers can be developed?
  - The words, "Eliminate the problem" is no good (we mean "corrective action").
  - Page 41 Response report.
  - Complaints should not be Ash Grove's to decide if it triggers corrective actions.
  - Barge operations cause problems.

Lyle Turnbull

- Boats are covered with dust.
- There are many sources in the Duwamish.
- Nucor Steel is also a source at Boulder Place (west of John Davis Marina).
- Dust affects the seams in the canvas of sails.
- Cheap shot.

Dana Stahl (POS Hygienist)

- Tires contain (dioxin okay, phthalates, heavy metals).
- More PM10 samples needed from the baghouse.
- The dust comes from more areas than just the baghouse.
- Excess emissions should be reported.

Kay Wisner (boat owner)

- Dust has been a big time problem, but in the last couple years there have some changes for the better. Ash Grove's measures seem to have been working.
- She appreciates boat cleaning & notification of emission events and they did a good job on this action.
- She does not like to continually need to go to Ash Grove.
- The same offers have not been made to all the boat owners.
- The offers need to be fair for everybody.

- The dust from barge activities is still a major issue.
- The barges are so large they are much closer to our boats in the marina.
- There needs to be offsite monitoring that is neutral (what is the dust & where is it coming from?).
- PM monitoring should include barge activities.
- There needs to be covers on the conveyors!
- Monitor all activities because dust comes from many sources at this plant.
- Ash Grove should be sprinkling their barges more often.
- The coal and limestone dust is also very abrasive.
- The boat owners expect some damage due to their location near the plant.
- If you cause the dusting problem you should be required to clean it up!
- The dust grows mildew on the canvas on the boats.
- There needs to be offsite monitoring.
- There needs to be a task force to get to the root of the problem.
- There are lots of companies in the area.
- The Agency needs to do more inspections.
- The permit should require more actions.
- The dusting is an ongoing problem.

Bruce Andre

- He shows a 4/15/94 video tape of dust fallout.
- He shows dust from Ash Grove.

Gerry Brown

- He says that mistakes have been made in the past.
- He says that Ash Grove is working hard to prevent problem in the future

Modification 1 to Operating Permit (11/17/06)

The modification of Ash Grove's Air Operating Permit is triggered by the incorporation of Notice of Construction and Application for Approval No. 9229 to allow the burning of a limited amount of used oils in the cement kiln.

The Project description for NOC No. 9229 is:

> Used oil firing system including tanks, pumps and piping, using existing burner, with the following new equipment: (1) 20,000 gal used oil holding tank, (1) 6 gal/min pump, (1) Mass flow meter, (1) 3/4" pipe with nozzle fitted inside existing ignition sleeve of existing burner.

This Order of Approval No. 9229 is for the limited use of liquid used oil as fuel in addition to the currently approved fuels in the cement kiln. A description of the Conditions of this Order of Approval are added below.

This Order of Approval No. 9229 cancels and supersedes Order of Approval No. 5687 dated January 11, 1995. Order of Approval No. 5687 allows a very small amount of internally generated used oils to be burned in the cement kiln. However, because Order of Approval No. 5687 is being replaced with Order of Approval No. 9229, the current Air Operating Permit needs to be opened and modified to include Order of Approval No. 9229.

This Order of Approval No. 9229 is being incorporated into the Air Operating Permit as a significant modification. All other changes in the Air Operating Permit are minor. These minor changes include updating EPA SIP approval dates and recognizing required testing activities that have already been satisfied.

For further information and details refer to Puget Sound Clean Air Agency Notice of Construction Work Sheet No. 9229 on file at the Agency. This significant modification of the operating permit is being co-processed with the proposed Order of Approval, sharing the same public comment period on both permit actions. Following the public comment period, the AOP will also be submitted to EPA in a proposed permit form, as described in WAC 173-401-810.

The following describes the conditions of approval of Order of Approval No. 9229.

THE FOLLOWING LISTS AND DESCRIBES CONDITIONS OF ORDER OF APPROVAL NO. 9229

GENERIC CONDITIONS

1. Approval is hereby granted as provided in Article 6 of Regulation I of the Puget Sound Air Pollution Control Agency to the applicant to install or establish the equipment, device or process described herein at the INSTALLATION ADDRESS in accordance with the plans and specifications on file in the engineering Division of Puget Sound Clean Air Agency.

2. This approval does not relieve the applicant or owner of any requirement of any other governmental agency.

> *Conditions No. 1 & 2 are generic for all orders of approval.*

BURN NON-HAZARDOUS USED OIL

3. Ash Grove shall limit used oil to non-hazardous as defined by WAC 173-303-515, Special Requirements for Used Oil Burned for Energy Recovery, or by WAC 173-303-090, Dangerous Waste Characteristics. Ash Grove is authorized to burn used oils meeting the material specifications in Condition No. 5 of this order.

> *Conditions No. 3 limits the type of used oils to assure that Ash Grove does not burn hazardous or dangerous waste materials. The sample procedures and testing methods are contained in or referenced by these cited regulations.*

4. Ash Grove shall limit the total amount of used oil injected into the kiln to 8640 gal/calendar day. Ash Grove shall monitor and maintain daily records of the volume of used oil injected into the kiln and the number of kiln operating hours/calendar day. Ash Grove shall submit these records on a monthly basis with the required CEMS. Examples of used oil include:

(a) Used oils;
(b) Refined oil tank bottoms;
(c) Raw crude tank bottoms;
(d) Heavy vacuum gas oil waste;
(e) Off specification fuel oil.

> *Conditions No. 4 limits the daily injection rate of used oils and requires monthly reporting of usage. Examples of used oil are included.*

5. Ash Grove shall only burn used oils meeting the following limits as delivered:

(a) As less than or equal to 5 ppm;
(b) Cd less than or equal to 2 ppm;
(c) Cr less than or equal to 10 ppm;
(d) Pb less than or equal to 100 ppm;
(e) PCB less than or equal to 50 ppm;
(f) Total Halogens less than 1000 ppm;

(g) Flash Point greater than or equal to 100°F;
(h) Heat content between 5,000 Btu/lb to 19,000 Btu/lb.

Conditions No. 5 limits the used oil burned to specific criteria. By accepting used oils for burning in the kiln which meet these criteria Ash Grove will remain below the trigger points for dangerous or hazardous materials as specified in the WAC 173-303-515, WAC 173-303-090. EPA has specification for burning used oil. For example applicable standards for burning of used oil containing PCB are regulated in 40 CFR 761.20(e). In addition the requirements of 40 CFR part 279, subparts G and H apply to the marketing and burning of used oil that is above the EPA trigger values.

However, because this Order of Approval is specifically for regulating air emissions it is the responsibility of Ash Grove to maintain knowledge of and compliance with all applicable regulations and to avoid triggering applicability criteria.

USED OIL DELIVERIES

6. Ash Grove shall:

(a) Authorize the person receiving and reviewing used oil shipments the authority to reject materials exceeding standards of this approval.
(b) Obtain a signed laboratory report from the oil supplier verifying each shipment of used oil received meets Conditions No. 5(a) through (h).
(c) Maintain a used oil delivery log and record in this log the name of the supplier, the delivery date, the volume of used oil and a signed laboratory report of each shipment of used oil received.

Conditions No. 6 lists the characteristics and parameters of the used oils that Ash Grove will follow to assure that the used oil is properly managed and monitored.

7. Ash Grove shall calibrate the used oil flow meter at least once per calendar year and maintain records of that calibration.

This annual calibration will assure that the used oil flow rate is correctly maintained below the 8640 gal/day limit.

SOURCE TEST

8. Ash Grove shall submit a source test plan for Condition No. 9(a), (b), (c), (d), (f), (g) and (h) no later than 30 days after the completion date specified in the Notice of Completion for this Order, meeting Regulation I, Section 3.07 with sampling methods, analytical procedure and testing dates. Ash Grove shall also follow 40 CFR 63, Subpart A and Subpart LLL for Condition No. 9(e) (Dioxin/Furan) including determining the average inlet temperature of the particulate matter control device.

Conditions No. 8 requires a source test to be performed and links the testing to the details of Condition No. 9.

9. Ash Grove shall complete performance source testing while operating with and without the injection of used oil. These tests shall be conducted while burning coal but not injecting tires and with the raw mill both operating and not operating. All tests shall be performed no later than 90 days after the completion date specified in the Notice of Completion with the following methods:

(a) Opacity (CEMS);
(b) SO2 (CEMS);
(c) NOx (CEMS);
(d) CO (CEMS);
(e) Formaldehyde (Method 0011/SW-8315);
(f) HCl (EPA Method 26A)
(g) Metals (EPA Method 29);
(h) Dioxin/Furan (EPA Method 23).

Conditions No. 9 specifies the parameters that need to be measured and the methods for testing. The tests are to be done under the specified conditions.

10. During the tests required in Condition No. 9, Ash Grove shall record the following data:

(a). Main Baghouse inlet temperature following 40 CFR 63.1349(b)(3);
(b) Type and quantity of clinker manufactured for cement;
(c) Type and quantity of raw materials added to kiln;
(d) Type, quantity and fuel Btu added to the kiln (including used oil);
(e) Burnability Index; and
(f) Variability of raw mix.

Conditions No. 10 specifies the operating parameters that need to be monitored, recorded and reported with the source test report.

RECORDS

11. Ash Grove shall maintain written records required by this Order of Approval on site, in addition, Ash Grove shall retain each record for at least five years and make them available to Puget Sound Clean Air Agency personnel upon request.

Conditions No. 11 provides an Agency Inspector the ability to request records.

OA 5687 SUPERSEDED

12. Order of Approval 9229 cancels and supersedes Order of Approval No. 5687 dated January 11, 1995.

Conditions No. 12 simply deletes the old order and replaces it with the new order.

ADDITIONAL CHANGES PROPOSED IN DRAFT MODIFICATION TO ASH GROVE'S AIR OPERATING PERMIT

Three additional groups of changes have been made as a part of the draft modification to Ash Grove's operating permit. These changes are grouped as follows:

Inapplicability of Washington's Solid Waste Incineration Facility Regulation

The Washington Department of Ecology updated the solid waste incineration facility regulation (WAC 173-434) on December 22, 2003. The previous version of this regulation (adopted in 1990) was an applicable requirement for Ash Grove and previously included in their permit. With the adoption of the latest version of WAC 173-434, Ecology determined that a facility like Ash Grove would not be subject to the rule providing the substitute fuels used were those defined in the new regulation. The 1990 version of WAC 173-434 was included in the approved Washington State Implementation Plan (SIP). That version remained an applicable requirement in Ash Grove's permit until EPA took final action to update Washington's SIP. That occurred on September 6, 2005. Ash Grove's operating permit was originally written to reflect that WAC 174-434 would no longer be an applicable requirement when EPA approved the new regulation in the SIP. Thus, WAC 173-434 has not been an applicable requirement since that EPA effective date and this modification removes the details of the 1990 versions of WAC 173-434 from the permit and shows the current version of that regulation as in inapplicable requirement.

Other SIP Changes Updated

Other SIP actions taken by EPA since the original operating permit was written have been completed. The operating permit included both the SIP approved versions of regulations and the SIP pending versions. The permit included statements that the SIP pending regulations would supersede the previous regulation upon approval in the SIP. Where that has occurred, the obsolete requirement has been deleted to clean up the permit document.

Event Related Permit Terms Satisfied

When an operating permit term is a single event requirement and the event has been satisfactorily completed, that requirement may also be removed from the permit. In this case, Ash Grove had a requirement to complete a performance test on the coal mill. That has been completed (and compliance was demonstrated). Thus, it no longer represents an active permit requirement. It has been deleted in the draft modified permit to clean up the document.

The removal of obsolete or superseded permit conditions in this draft modified permit have in some places let to sections listed as " **[RESERVED]** ". This was done to avoid reformatting the entire document and renumbering cross referenced citations. When a deleted section could be used without that complication, it was used for new requirements associated with the incorporation of NOC No. 9229 into the operating permit.

Public Comments for Significant Modifications Received during the 30-day Public Comment Period

Comment from People for Puget Sound

e-mailed to the Agency 1/16/2007

January 15, 2007

Fred Austin

Engineer

Puget Sound Clean Air Agency

110 Union Street, Suite 500

Seattle, WA 98101

Via email: freda@pscleanair.org

RE: Draft Notice of Construction Order of Approval No. 9229 and draft Modification of the Air Operating Permit for Ash Grove Cement Company (Ash Grove)

Dear Mr. Austin,

Thank you for the opportunity to comment on the *a draft Notice of Construction Order of Approval No. 9229* and *draft Modification of the Air Operating Permit for Ash Grove Cement Company (Ash Grove*), located at 3801 E Marginal Way South, Seattle.

People For Puget Sound is a nonprofit, citizens' organization whose mission is to protect and restore Puget Sound and the Northwest Straits, including a specific goal to protect and restore the 2,000 miles of Puget Sound shoreline by 2015.

Ash Grove is a major emitter and releases over 100 tons of NOx and SO2 annually. Ash Grove is now requesting that they be permitted to burn used oil (up to 12% Btu basis) in addition to tires (at a rate of up to 12 tons per day). The use of these fuels moves the facility into a waste incinerator mode and raises serious human and wildlife health concerns.

Our specific comments follow:

1. ***Re-evaluation of the facility.*** Given that Ash Grove was granted a permit to burn tires in 1995 and they are now asking to burn used oil, we strongly feel that the facility permit should be re-evaluated. Since 1995, Chinook salmon have been listed as endangered, the Duwamish River has been listed as a Superfund Site, and more and more concerns have been raised about human health in the Duwamish Valley. It appears that each air-permitted facility in the Duwamish Basin is allowed to continually ratchet up and add more and more components to their facility (or fuel stream) rather than following a

continual process of ratcheting down toxic emissions in order to protect wildlife and human health.

2. ***Cumulative Impact.*** Our second major concern is that permits and permit changes are granted without consideration of cumulative impacts. According to the Engineer's Report, Engineer's Report mercury emissions described in the facility's 2003 TRI Report totaled 34 lbs/year. Lafarge, as reported in the recent public meeting has mercury emissions of about 84 lbs/year (baseline, prior to burning tires!). Lafarge's formaldehyde emissions are about 17,260 lbs/year. Chromium-6 is also a contaminant of concern throughout the Duwamish Basin. There are likely a number of other toxic chemicals that are cumulatively impacting human and wildlife health but we have not yet seen the WA Department of Health study (which was due out in the fall of 2006).
3. ***Emissions of toxic chemicals.*** People For Puget Sound is concerned about the release of toxic chemicals such as heavy metals and dioxin from this facility. Most of these toxic emissions are not required to be regularly monitored by the facility. We are especially concerned that lead and cadmium will be increased from this facility with the use of used oil. Lead (according to the Engineer's Report) is up to 100 times higher in used oil than in coal.
   a. The Statement of Basis includes an emission summary for 1995-2001. Why are recent data not included as an update to the Statement?
   b. Why is PSCAA not requiring Ash Grove to report plant-wide fugitive emissions?
   c. The Port of Seattle and its tenants have had significant complaints about material falling on their property, buildings and cars and the potential human health impacts. They have requested that Ahs Grove install reliable and continuous off-site monitoring. We agree with this request and further we request that these data be presented to the public in a separate and easily understood report (that includes a map). It is not acceptable to state that off-site monitoring would be compromised by other pollutants. A sound monitoring program would allow for distinguishing between different sources and if, in fact, there are multiple significant sources of pollutants, the public has a right to this information.
   d. The used oil regulations allow up to 50 ppm PCBs in oil that might be burned at Ash Grove. This is not acceptable in the source area for a Superfund Site (the Duwamish River) in which millions of dollars are being spent to clean up PCBs. The permit should require that any oil burned at Ash Grove must have very low PCBS – on the order of <5 ppm or lower. Also, the emissions should include a requirement for regular PCB monitoring.
4. ***Poor compliance History.*** Ash Grove has a very poor compliance history. Most of the violations occurred in the late 1990's-early 2000's and that leads one to conclude that either Ash Grove has improved their compliance or PSCAA has lost staff capacity and is not able to review their files and inspect their facility as often. We would like to know if compliance inspections and reviews have decreased. The past poor compliance signifies that extra precaution must be taken with the facility, especially in a transition period.
5. ***Equivalent scrutiny as Lafarge.*** If permitted, the facility should be required to meet all of the testing and monitoring requirements that Lafarge is being required to do currently.

The public should be allowed to see the testing results and be invited to a public meeting to discuss the results.

6. ***Map of deposition plume***. We would like to see a map that shows the area of deposition of material from the air plume of Ash Grove. If such a map is not available, we strongly feel that Ash Grove should be required to prepare a map.
7. ***Continuation of Dioxin tests.*** The Engineer's Reports states that: "This regulation requires performance tests requirement for dioxin/furan emissions every 30 months after the compliance effective date of June 14, 2002. The initial performance test was completed by Ash Grove on May 29-30, 2002. Ash Grove followed this initial test by conducting their required 30-month performance test on October 13-14, 2004 within the required time period." It appears that these dioxin tests were discontinued. We request that these tests be required on a continuing basis.
8. ***Grinding Wheel and toxic chemicals***. We are concerned that the raw mill grinder is part of the pollution control for this facility and certain toxic chemicals, such as HCl and formaldehyde, are not well controlled during the 10% of the operational time when the grinding wheel is not in use. According to the Engineer's Report: "When the grinder is not operating the gases bypass the grinder and go directly to the main baghouse. When the raw mill grinder operates the gases flowing through grinder tend to be scrubbed of some of the pollutants." What assurance do we have that chemicals are monitored at both times – when the grinding wheel is in operation and when it is not. How are we assured that significant increases are controlled when the grinding is not operational?
9. ***SEPA Review***. The Report states "The Agency, as the lead agency for this proposal, has also made a preliminary determination that the proposal would not have a probable significant adverse impact on the environment. An environmental impact statement (EIS) is not required under RCW 43.21.030(2)(c). This decision was made after review of a completed Environmental Checklist and other information on file at the Agency." We disagree with this assessment because of the cumulative impacts of this facility combined other facilities and other sources in the Duwamish Basin.
10. ***Tires.*** We strongly object to the burning of tires at this facility. We do not have a complete data set to show that burning tires in the Duwamish cement facilities is safe for human and wildlife health. We recognize that this facility was previously permitted to use tires, but this use should be re-evaluated in light of cumulative impacts of the multiple facilities in the Duwamish. Further, the Engineer's Report states: "Also because burning tires (as approved per Order of Approval No. 5755 (approved 3/30/95) reduces emissions compared to coal, the use of tires are not included in this analysis and the conditions for source testing requires not burning tires with used oil in the kiln." We disagree that emissions are reduced for all toxics – and are particularly concerned about dioxins, mercury and other metals emissions associated with tire burning.
11. ***Unknown contaminants in used oils***. We are concerned that unknown contaminants could be introduced into used oils due to human error. What assurance do we have that the used oils will be relatively clean?
12. ***Why are not tests required for tire burning conditions as well?*** Engineer's Report: "Ash Grove shall complete performance source testing while operating with and without the injection of used oil. These tests shall be conducted while burning coal but not

injecting tires and with the raw mill both operating and not operating." We believe that the tire burning condition should also be tested and the data presented to the public.

13. ***Economics trumps human health.*** The Engineer's Report states "Ash Grove and Lafarge are requesting approval to burn alternative fuels. Ash Grove wants to burn waste oil (Lafarge was approved to burn waste oils several years ago). Lafarge wants to burn whole tires (Ash Grove was approved to burn whole tires several years ago). So the two plants want to expand their fuels to compete directly with each other." We feel that economic considerations are being placed over the concerns about human and wildlife health.

Thank you for your consideration. If you have any questions, please contact me at (206) 382-7007 or htrim@pugetsound.org.

Sincerely,

Heather Trim

Urban Bays Coordinator

Agency Response to People for Puget Sound

Ash Grove's proposal is based on replacing the burning of 100% coal fuel with the burning of a blend of 88% coal and 12% used oil as limited by the Agency permit conditions. The burning of used oil replaces a portion of coal which is a cleaner fuel. The burning of tires as a fuel was not part of this analysis because the emissions from tires and coal is lower than using 100% coal and because Ash Grove obtained authorization to uses whole tires as a substitute fuel previously (Order of Approval No. 5755 dated March 30, 1995). Tires are typically a cleaner fuel than coal. Therefore, the most conservative scenario is to compare the emissions from burning a blend of coal and used oil with the emissions from burning 100% coal.

The operation of the cement kiln at Ash Grove does not trigger the definition of incinerator as defined in WAC 173-434 nor is the raw materials or fuels classified as solid waste. This cement kiln operates at temperatures above 2800°F which is over a 1000°F hotter than that found in incinerators (incinerators operate at 1600 - 1800°F). Also, because a cement kiln is hundreds of feet long the combustion residence time lasts for many seconds versus fractions of seconds as found in incinerators.

<u>Comment #1</u> *Re-evaluation of the facility*

The Ash Grove application to burn used oils has been evaluated following Puget Sound Clean Air Agency Regulation I, Article 6; WAC 173-400; and WAC 173-460. These rules give this Agency permitting authority for evaluating the establishment of a new source. In this case, the burning of used oil in this existing cement kiln as a replacement fuel for coal is defined as a new source and so this Agency's approval of NOC 9229 would only be for

the new fuel. All the existing equipment and operations have already been evaluated and approved under existing Orders of Approval prior to this Notice of Construction.

Comment #2 ***Cumulative Impact***

The Table named "AGENCY Estimation of Maximum Metal Emissions while Burning Used Oil with Coal" above compares the maximum annual emission of metals from burning 100% coal fuel with the burning of a blend of 88% coal and 12% used oil. Typical levels of lead in coal have been found to be about 0.9 ppm. WAC 173-303-515 limits used oil to 100 ppm of lead. The difference between burning 100% coal and burning 88% coal with 12% used oil blend is 0.074 lb of lead per year (0.002 lb of cadmium per year). This analysis assumes none of the metals become incorporated into the cement product and that none of metals are captured by the baghouse.

The every small increase in lead and cadmium assumed in the worst case scenario would produce a very small ambient impact as follows:

Compound	Averaging time	Maximum Emissions	Maximum Ambient Impact	Ambient Source Impact Level (ASIL)	% of ASIL
Lead	24-hour	1.0×10^{-06} g/s	5.3×10^{-9} μg/m^3	0.050 μg/m^3	0.00001%
Cadmium	Annual	1.2×10^{-07} g/s	2.4×10^{-8} μg/m^3	0.00056 μg/m^3	0.004%

Therefore, the ambient impact of lead or cadmium is significantly below the acceptable source impact levels at the point of maximum ground level concentration. These are the only two metal constituents which were projected to have emission increases (using the analysis described above). The proposed approval conditions include testing to verify these conclusions. A cumulative impacts analysis, as envisioned by this comment, is not a part of the Notice of Construction review as the ASIL's define the criteria for approval. The Washington Department of Health study referenced was begun with no direct linkage to any new or modified source action as a trigger and a cumulative impacts review is broader than any source specific application.

Comment #3a

The Statement of Basis was written to support the Title V air operating permit that was issued May 15, 2004. The emission summary for 1995 to 2001 was the latest information available at that time prior to issuing the permit.

The reported emissions for the years 2002 to 2005, which is also available to the public, are as follows:

CAS #	Chemical Name	VOC	TAC	HAP	2002 Total Tons	2003 Total Tons	2004 Total Tons	2005 Total Tons
CO	Carbon Monoxide	No	No	No	1414	1197	1285	1468
NO2	Nitrogen Oxides	No	No	No	1213	1035	1266	1580
PM10	Particulate Matter	No	No	No	50	39	43	51
PM2.5	Particulate Matter	No	No	No	40	31	34	40
SO2	Sulfur Oxides	No	No	No	188	148	150	34
50-00-0	Formaldehyde	Yes	Yes	Yes	*	*	5	6
67-64-1	Acetone	No	Yes	No	*	*	6	7
7664-41-7	Ammonia (NH3)	No	Yes	No	*	*	3	3
Totals VOC					*	*	5	6
Totals TAC					*	*	14	16
Totals HAP					*	*	5	6
* Not Measured before 2004								

<u>Comment #3b</u>

Fugitive emissions are addressed in the Title V permit. The frequency of fugitive emissions and complaints have significantly decreased since the issuance of the Title V permit.

Ash Grove's permit contains significant procedures requiring monitoring, recordkeeping and reporting whenever fugitive dust emissions are observed or complaints are received. Fugitive dust emissions by virtue of the fact that they are not released from stacks generally do not have quantifiable methods for direct measurements, making the exercise of estimating fugitive dust emissions an attempt in quantifying the unquantifiable. The current regulations governing visible emissions and the requirements for reasonable control measures, roof top inspections and fugitive dust control measures are adequate to maintain compliance with the permit.

<u>Comment #3c</u>

While Ash Grove has had significant dust complaints in the past, currently there have been few dusting incidences. The situation as it stands at Ash Grove indicates that historical fugitive dust problems have been addressed through improvements in equipment and operational practices. This Notice of Construction is for the burning of used oil as a supplemental fuel whose emissions are controlled by the main baghouse which is not a fugitive dust emission point.

Comment #3d

One of the best ways to dispose of PCBs which are persistent environmental chemicals is by destruction in a cement kiln. Condition No. 5 limits PCB below the trigger value set by EPA and Condition No. 6 requires monitoring each shipment of used oil.

Comment #4

The Agency staff associated with activities at Ash Grove and the inspection frequency has not changed. Also, please see responses to Comments #3c and #5.

Comment #5

Ash Grove is required to operate a system of continuous emission monitors for opacity, SO_2, NOx, and CO. Lafarge has continuous emission monitors for opacity and SO_2. The source testing requirements contained in Agency Orders for both Lafarge and Ash Grove help to establish emission pollutant factors not directly measured by the continuous emission monitors.

Both plants measure dioxin as required by 40 CFR 63, Subpart LLL. Ash Grove like Lafarge, has made equipment improvements and changes as parts of Agency Orders that have helped to significantly improve operations, control emissions and reduce complaints.

Condition No. 9 requires the measurement of formaldehyde, HCl, metals, and dioxin.

All Agency records are available to the public including the testing reports required for Ash Grove.

In addition to inviting public comments for this Notice of Construction applicaiton, the Agency has held two public hearings in response to citizen inquires for this proposed action.

Comment #6

The emissions from the Ash Grove stack are controlled with a 200,000 cubic feet per minute baghouse. Large sized particulates (greater than 10 microns) that would be expected to settle out of the ambient air and become deposited on the ground are very well controlled (more than 99.9% are captured). Because the Agency makes the conservative estimate of comparing the maximum ground level concentration from the model to the concentration from the <u>Acceptable Source Impact Levels</u> table, the point of maximum concentration is not specified. This effectively assumes that the maximum concentration is everywhere.

Comment #7

As you indicate, dioxin tests are required every 30 months. The dioxin testing is being conducted on schedule at Ash Grove and emissions continue to demonstrate complaince with the requirements and standards of 40 CFR 63.1349(d). Dioxin source test are repeated every 30 months. Ash Grove conducted their most recent dioxin test during the

week of February 12, 2007. The results will be available in less than 60 days. The last dioxin source test results on October 13, 2004, required by 40 CFR 63, Subpart LLL, shows that Ash Grove is well below the required NESHAPS standard.

The dioxin standard is 0.02 ng/dscm (0.02 nanogram per dry standard cubic meter).

The October 13, 2004 dioxin source test measured dioxin with the following results.

Raw Mill - ON -- 0.000431 ng/dscm.

Raw Mill - OFF -- 0.002370 ng/dscm.

The status when the raw mill operates occurs about 90% of the time, while the status when the raw mill is not operating occurs about 10% of the time during the year.

Therefore, Ash Grove's emissions of dioxin is about 2% of the standard (during 90% of the year) and the emissions of dioxin is about 12% of the standard (during 10% of the year).

<u>Comment #8</u>

There are no continuous emission monitors for HCl or formaldehyde at this plant. These emissions are measured by source tests on the main stack baghouse during raw mill grinding operations.

The raw mill grinder is not an emission control device. It is equipment designed for processing raw materials in preparation for the kiln. The raw mill grinder (about 4 - 5 feet in diameter) operates about 90% of the time the kiln operates. The raw mill grinder is designed to be replaced during the balance of the kiln's operation. The function of the raw mill grinder is to grind raw materials to a powder usable in the kiln to make clinker for cement. The main raw material is primarily limestone with additions of lime, sand, clay, iron ore, aluminum silicates, natural gravel, fly ash, and gypsum. There are also smaller amounts of materials added including calcium, silica, iron, and alumna, bottom ash, slag and gypsum board. Waste heat from the kiln, which would otherwise be lost, is used in the processing of the raw materials. By using this waste heat Ash Grove improves kiln efficiency which reduces the use of coal and thereby there occurs a reduction in the generation of CO_2, a greenhouse gas. This reduction in greenhouse gases indirectly affects emissions.

During the preparation of materials for the kiln the raw mill grinder does adsorb some gases when operating. However, the air pollution control system has been designed to effectively control emission below the standards even when the raw mill grinder is not operating.

As mentioned above Ash Grove Cement is subject to Subpart LLL of the NESHAPS. When any cement plant emits greater than 10 tons per year of any one toxic chemical or 25 tons per year of all toxic chemicals, enhanced monitoring is triggered as a NESHAPS point source. Ash Grove continues to monitor their emissions demonstrating that they satisfy the NESHAPS area source criteria.

<u>Comment #9</u>

Please see responses to Comments No. 1 and 2 above.

<u>Comment #10</u>

Source tests preformed at Ash Grove for Order of Approval 5755 demonstrated compliance with the standards and showed that the emissions met the ASIL values. The testing results showed a decrease in emissions with the burning of tires. Order of Approval 9229 is conservative in requiring Ash Grove to only use coal and used oils during the compliance tests.

<u>Comment #11</u>

The many conditions in the proposed Order of Approval define and delineate the required testing and monitoring Ash Grove is required to perform to maintain compliance while adding used oil as fuel to the cement kiln. Each shipment of used oil is monitored as required by Conditions # 3, 4, 5 and 6.

<u>Comment #12</u>

See response to Comment # 10 above.

<u>Comment #13</u>

By allowing both cement plants to burn these additional fuels, the air emissions will in general be decreased. If these fuels are not burned in cement plants these fuels could unnecessarily be burned in locations with far less efficiency with significant increases in emissions. These materials would allow increased recycling of materials and increase efficiency of energy use.

Comment from Heidi Raykeil & JB Tellez

Comment on Air
Operating Permit for ,

Dear Mr. Austin --

My neighbor, Bob Anderton couldn't have put it better -- our family is in total agreement with his sentiments. Please don't allow my children to grow up breathing worse air than they already are down here. It is not safe.

From Bob's letter --

Dear Mr. Van Slyke and Mr. Austin:

I am not a scientist or an environmental lawyer, but I am a resident of Seattle's South Park neighborhood who is affected by poor air quality. I do not understand how burning "8640 gallons per day of used oils" is not significant. I do understand the significance of a finding of non-significance, however.

I am requesting that the determination of non-significance be reviewed and the application be scrutinized to allow for additional pollution controls. South Park is already burdened by poor air quality. If the Environmental Protection Agency under the Bush administration is unwilling or unable to do its job to protect people from pollution, then local agencies must rise to this challenge. Please protect us.

South Park residents understand that they live in an area mixed with industrial and residential uses and we value this. We do not wish to shut down industries. However, we want to breathe easy and, with the worst air quality in Seattle likely to get worse with unknown used oil contaminants, we cannot, at this time, do so.

Please let us know how the Puget Sound Clear Air Agency can help.

Thank you,

Bob Anderton

Sincerely,

Heidi Raykeil and JB Tellez

1010 S. Thistle St.

Seattle, WA

206-763-3866

Agency Response to Heidi Raykeil & JB Tellez

Please see the Agency response to Bob Anderton's comment.

Comment from Bob Anderton

Ash Grove Cement
Hearing Question anc

Dear Mr. Van Slyke and Mr. Austin:

I am writing as to whether yesterday's public hearing was cancelled due to the snow and ice. If was, please inform me (and the community) of the next hearing date. If it was not, please register this email as my comment and, if possible, respond to it.

I am not a scientist or an environmental lawyer, but I am a resident of Seattle's South Park neighborhood who is affected by poor air quality.

I do not understand how burning "8640 gallons per day of used oils" is not significant. I do understand the significance of a finding of non-significance, however.

I am requesting that the determination of non-significance be reviewed and the application be scrutinized to allow for additional pollution controls.

South Park is already burdened by poor air quality. If the Environmental Protection Agency under the Bush administration is unwilling or unable to do its job to protect people from pollution, then local agencies must rise to this challenge. Please protect us.

South Park residents understand that they live in an area mixed with industrial and residential uses and we value this. We do not wish to shut down industries. However, we want to breathe easy and, with the worst air quality in Seattle likely to get worse with unknown used oil contaminants, we cannot, at this time, do so.

Please let us know how the Puget Sound Clear Air Agency can help.

Thank you,

Bob Anderton

Bob Anderton
Bike Lawyer and More
Representing People, Not Corporations

ANDERTON LAW OFFICE
710 Second Avenue, Suite 700
Seattle, Washington 98104

Phone: 206-262-9290
Fax: 206-223-0884 E-mail: bob@andertonlaw.com

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Agency Response to Bob Anderton

The burning of used oils as a fuel in the cement kiln means there is less coal burned as fuel.

This kiln has been permitted to burn coal. This application would allow burning used oils as a substitute for some coal in the kiln. The emissions from burning used oils are less than that from burning coal. Please see the Agency response above to Heather Trim especially the Agency response to comment No. 3.

Comment from M.C. Halvorsen

FW Meeting
Regarding Ash Grove

From: m.c. halvorsen [mailto:teddy2halle@yahoo.com]
Sent: Thursday, January 11, 2007 12:41 PM
To: Steve Van Slyke
Subject: Meeting Regarding Ash Grove Proposal

Dear Steve:

Although I had planned to attend the meeting tonight, January 11, 2007 at the South Park Center, I find that the road are too icy for me to be out driving.

I do have a question and wanted to bring it to the attention of the people in charge of this proposal. Why isn't the Company interested in installing scrubbers which would prevent particles from entering the air? Is it cost? If so, couldn't a tax credit of some kind be given because it would improve the overall quality of the air in the area?

I don't know what the objection to scrubbers is. In europe, they are required on all incinerators. Back east, the incinerators are proud of thier scrubbers. WhI was in the Mid-West, people were bragging how improved their air quality was by installing scrubbers. Seattle likes to brag that it leads the nation in environmental issues, but it is certainly lagging behind on this one.

M. C. Halvorsen

10002 Aurora Ave. N., 35546

Seattle, Wa 98133

206-766-9416

Agency Response to M.C. Halvorsen

Ash Grove Cement operates a baghouse to control particulate with a dry scrubber to control acid gases. There are many different technologies used to control air pollution emissions. The operation of a baghouse at a cement plant is recognized as having the best efficiency at capturing particulate.

Comment from Ash Grove Cement

January 15, 2007

Mr. Fred Austin

Puget Sound Clean Air Agency

110 Union Street, Suite 500

Seattle, WA. 98101-2038

Re: Comments on Notice of Construction # 9229 and Draft Modification of Air Operating Permit # 11339

Dear Mr. Austin:

Ash Grove Cement Company submit the following comments regarding Notice of Construction # 9229 and Draft Modification of Air Operating Permit # 11339.

The header on the Statement of Basis document should be changed from Saint-Gobain to Ash Grove Cement.

1. Section I.B.6 of the Statement of Basis document incorrectly specifies the emission standard for dioxins and furans. The standard should state that the dioxin limit of 0.4 ng/dscm (TEQ) at 7% O2 when the average of the Kiln baghouse temperatures **are equal to or less** than 400 F during the performance test (40 CFR 63.1343(d)(2)) and 0.2 ng/dscm (TEQ) at 7% O2 when the average of the Kiln baghouse inlet temperatures are **greater** than 400 F during the performance test (40 CFR 63.1343(d)(1)).
2. Section EU 1.26 of the draft Title V permit. The applicable emission standards for dioxins and furans apply to air pollution control device inlet temperatures, not the mill mode of operation. Ash Grove requests this requirement paraphrase be modified to reflect the standard as written.
3. Section EU 1.36 of the draft Title V permit. The referenced EU 1.50 in the requirement paraphrase section does not exist. The reference should be corrected to read EU 1.38.
4. Section II.B.5 (a) of the draft Title V permit and item #4 of NOC 9229 requires that kiln operating hours are to be reported on a daily basis. This additional requirement to that is unnecessary. Section C.4(c) currently requires in kiln operating hours are to be reported on a monthly basis. Ash Grove requests that this additional reporting requirement is deleted from Section II.B.5(a) and Section C.4(c) the draft AOP and item #4 NOC 9229.
5. Section II.B.12 (b) of the draft Title V permit and item #9(e) of NOC 9229. Rather than specify a source test method for Formaldehyde, HCl, and Metals, Ash Grove requests that it retain the flexibility to propose any air test method with written prior approval from the agency.

6. Section II.B.12 (b) of the draft Title V permit and item #9. Ash Grove questions the requirement to conduct performance tests both with and without used oil. The performance test should only require testing while using used oil to determine if the facility maintains its status as an area source and demonstrate compliance with other applicable emission limits.
7. Section II.B.12 (b) of the draft Title V permit and item #10 (e) and 10(f) of NOC 9229. The requirement to record the Burnability Index and Variability of the raw mix during the performance test has no relevance on whether the facility can demonstrate compliance with emission limits and should be deleted as a requirement.
8. Please note that the expected NOx, SOx, and CO data to be reported when the performance test demonstration is performed should not be used to project any longer-term emission increases for PSD analysis or anything else. If this is the case, a longer averaging time should be used and a pre-test baseline establish for comparisons to be made against.

Yours truly,

Gerald J. Brown

Manager Safety and Environmental

Agency Response to Ash Grove Cement

1. Section I.B.6 of the Statement of Basis document incorrectly specifies the emission standard for dioxins and furans. The standard should state that the dioxin limit of 0.4 ng/dscm (TEQ) at 7% O2 when the average of the Kiln baghouse temperatures **are equal to or less** than 400 F during the performance test (40 CFR 63.1343(d)(2)) and 0.2 ng/dscm (TEQ) at 7% O2 when the average of the Kiln baghouse inlet temperatures are **greater** than 400 F during the performance test (40 CFR 63.1343(d)(1)).

Correction noted.

2. Section EU 1.26 of the draft Title V permit. The applicable emission standards for dioxins and furans apply to air pollution control device inlet temperatures, not the mill mode of operation. Ash Grove requests this requirement paraphrase be modified to reflect the standard as written.

Correction noted.

3. Section EU 1.36 of the draft Title V permit. The referenced EU 1.50 in the requirement paraphrase section does not exist. The reference should be corrected to read EU 1.38.

Correction noted.

4. Section II.B.5 (a) of the draft Title V permit and item #4 of NOC 9229 requires that kiln operating hours are to be reported on a daily basis. This additional requirement to that is unnecessary. Section C.4(c) currently requires in kiln operating hours are to be reported on a monthly basis. Ash Grove requests that this additional reporting requirement is deleted from Section II.B.5(a) and Section C.4(c) the draft AOP and item #4 NOC 9229.

The requested change has been made to both the Order of Approval conditions and the operating permit document. The requirement for daily recording of used oil volume fired is directly related to the allowable volume, but a daily kiln operational hours record does not relate to this specific requirement.

5. Section II.B.12 (b) of the draft Title V permit and item #9(e) of NOC 9229. Rather than specify a source test method for Formaldehyde, HCl, and Metals, Ash Grove requests that it retain the flexibility to propose any air test method with written prior approval from the agency.

A provision has been added to allow for alternative methods to be used only after review and approval by the Agency.

6. Section II.B.12 (b) of the draft Title V permit and item #9. Ash Grove questions the requirement to conduct performance tests both with and without used oil. The performance test should only require testing while using used oil to determine if the facility maintains its status as an area source and demonstrate compliance with other applicable emission limits.

Previous tests have shown significant differences in emissions between the Raw Mill both "On" and "Off". These tests will verify the correct emissions for these two scenarios and also establish the correct emission factors for calculating annual emissions.

7. Section II.B.12 (b) of the draft Title V permit and item #10(e) and 10(f) of NOC 9229. The requirement to record the Burnability Index and Variability of the raw mix during the performance test has no relevance on whether the facility can demonstrate compliance with emission limits and should be deleted as a requirement.

In order to establish a base line and document differences between burning 100% coal versus burning a coal and used oils blend, the values for the Burnability Index and the variability of the raw materials need to be established to show that differences in emissions are caused by differences in fuels rather than any differences in raw materials or patterns caused by combustion parameters. Also, when Ash Grove requested the ability to increase the emission limit of NOx, part of the background of information included the changes that had occurred in the Burnability Index.

8. Please note that the expected NOx, SOx, and CO data to be reported when the performance test demonstration is performed should not be used to project any longer-term emission increases for PSD analysis or anything else. If this is the case, a longer averaging time should be used and a pre-test baseline establish for comparisons to be made against.

The Agency recognizes that these tests are designed to be used to document changes in emissions as a function of fuel changes. The results of these tests would help Ash Grove in estimating annual emissions based on the annual ratio of fuel usages.

Administrative Amendment 1 to Operating Permit (7/13/07)

Ash Grove requested an Administrative Amendment (received June 18, 2007) to the operating permit to delete the monitoring requirement in Section II.A.5 of the permit. This request represents a request to correct a typographical error found in the modified permit that was issued on May 17, 2007. In the permit modification action completed on May 17, 2007, the Agency deleted Condition I.A.12 of the permit because it was no longer an applicable requirement. Condition I.A.12 had included requirements found in Puget Sound Clean Air Agency Regulation I, Section 9.15(b) (*effective date 8/10/89*). That regulation was a SIP approved requirement when the original Ash Grove Air Operating Permit was issued on May 15, 2004. Subsequent changes to this Agency's regulations and SIP approval actions by EPA eliminated that as an applicable requirement. This superseded requirement that no longer exists related to vehicle track out and spillage of particulate matter on public roadways. Section II.A.5 of the permit represented a monitoring requirement created through gap filling for this one applicable regulation alone in the permit. When the SIP update eliminated the provision found in Condition I.A.12 in the permit, it ceased to be an applicable requirement. In an attempt to clean up the obsolete conditions in the permit, we deleted that requirement but failed to delete the monitoring provisions that were specifically linked to it. The Agency concurs with the request as an administrative amendment as it represents a typographical error and oversight in the preparation of the last modification. If this amendment were not completed, then the monitoring in Section II.A.5 of the permit would be an orphan, having no underlying requirement for the monitoring and without an authority for a gap filling permit term.

Administrative Amendment 2 to Operating Permit (12/2/10)

Ash Grove requested an Administrative Amendment (received October 12, 2010) to the operating permit to change the responsible official to Todd Hinton. That change was made November 1, 2010 and a letter to that effect was sent to Dan Peters who requested the update.

Administrative Amendment 3 (12/12/13)

Ash Grove requested an Administrative Amendment (received September 9, 2013) to change the responsible official to Carey Austell. That change was made December 23, 2013 and a letter to that effect was sent to Dan Peters who requested the update.

Administrative Amendment 4 (6/13/18)

Ash Grove requested an Administrative Amendment (received March 23, 2018) to change the responsible official to Laura McAnany. That change was made June 13, 2018 and a letter to that effect was sent to Dan Peters who requested the update.

pscleanair.org
Puget Sound Clean Air Agency

AIR OPERATING PERMIT

Puget Sound Clean Air Agency
1904 3rd Avenue, Suite 98101-3317
Seattle, Washington 98101

Issued in accordance with the provisions of Puget Sound Clean Air Agency (previously known as Puget Sound Air Pollution Control Agency) Regulation I, Article 7 and Chapter 173-401 WAC.

Ash Grove Cement Company, Inc. is authorized to operate subject to the terms and conditions in this permit.

PERMIT NO.: 11339	**DATE OF ISSUANCE**: May 15, 2004 Significant Modification 1 – May 17, 2007 Administrative Amendment 1 – July 13, 2007 Administrative Amendment 2 – December 2, 2010 Administrative Amendment 3 – December 23, 2013 Administrative Amendment 4 – June 13, 2018
ISSUED TO:	**Ash Grove Cement Company, Inc.**
PERMIT EXPIRATION DATE: May 15, 2009	

SIC Code, Primary:	3241 Hydraulic Cement Manufacturing
NAICS Code	32731 Hydraulic Cement Manufacturing
Nature of Business:	Hydraulic Cement Manufacturing
Mailing Address:	3801 E Marginal Way South, Seattle WA, 98106-1599
Facility Address:	3801 E Marginal Way South, Seattle WA, 98106-1599
Responsible Official:	Laura McAnany, Plant Manager
Telephone No.:	(206) 623-5596
FAX No.:	(206) 623-5355
Site Contact:	Gerry Brown, Safety/Environmental Manager
Telephone No.:	(206) 623-5596
FAX No.:	(206) 623-5355

Puget Sound Clean Air Agency Approval:

Carole Cenci, PE

Sara Conley
Permit Engineer

Carole Cenci
Compliance Manager

TABLE OF CONTENTS

I. EMISSION LIMITS AND PERFORMANCE STANDARDS

The following tables list the citation for the "applicable requirement" in the second column. The third column (Date) contains the adoption or effective date of the requirement. In some cases, the effective dates of the Federally Enforceable Requirement and the State Only Requirement are different because only rules approved by EPA through Sections 110, 111, and 112 of the federal Clean Air Act are federally enforceable and either the state has not submitted the regulation to the EPA or the EPA has not approved it.

The first column is used as an identifier for the requirement, and the fourth (Requirement Paraphrase) column paraphrases the requirement. The first and fourth columns are for information only and are not enforceable conditions of this permit. The actual enforceable requirement is embodied in the requirement cited in the second and third columns.

The fifth column (Monitoring, Maintenance & Recordkeeping Method) identifies the methods described in Section II of the permit. Following these methods is an enforceable requirement of this permit. The sixth (Emission Standard Period) column identifies the averaging time for the reference test method. The last column (Reference Test Method) identifies the reference method associated with an applicable emission limit that is to be used if and when a source test is required. In some cases where the applicable requirement does not cite a test method, one has been added.

In the event of conflict or omission between the information contained in the fourth and sixth columns and the actual statute or regulation cited in the second column, the requirements and language of the actual statute or regulation cited shall govern. For more information regarding any of the requirements cited in the second and third columns, refer to the actual requirements cited.

A. FACILITY-WIDE APPLICABLE REQUIREMENTS

The requirements in this section apply facility-wide to all the emission units regulated by this permit, except as otherwise stated in a permit condition.

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
Opacity Standards						
I.A.1	Puget Sound Clean Air Agency Reg I: 9.03(a)-(c)	3/11/99	Ash Grove shall not emit more than 20% opacity for a period or periods aggregating more than 3 minutes in any 1-hour period	II.A.1 General Opacity Monitoring	More than 3 min. in any 1 hr	Ecology Method 9A 7/12/1990 (See Section X)
I.A.2	WAC 173-400-040(1)	9/20/93	Ash Grove shall not emit more than 20% opacity for more than 3 minutes in any 1-hour period.	II.A.1 General Opacity Monitoring	More than 3 min. in any 1 hr	Ecology Method 9A 7/12/1990 (See Section X)
Particulate Standards						
I.A.3	Puget Sound Clean Air Agency Reg. I: 9.09	4/09/98	Ash Grove shall not emit particulate matter in excess of 0.05 gr/dscf from equipment used in a manufacturing process uncorrected for excess air	II.A.1 General Opacity Monitoring	(3) 1-hour runs	Puget Sound Clean Air Agency Method 5 (See Section X)
I.A.4	WAC 173-400-060 *This requirement* shall *be superseded by the 9/15/01 version of WAC 173-400-060 upon its adoption into the SIP* WAC 173-400-060 *(State Only)* *This requirement will become federally enforceable upon adoption into the SIP and will replace the 3/22/91 version of WAC 173-400-060.*	3/22/91 *9/15/01*	Ash Grove shall not emit particulate matter in excess of 0.10 gr/dscf from general process units, uncorrected for excess air	II.A.1 General Opacity Monitoring	(3) 1-hour runs	EPA Method 5 (40 CFR Part 60, Appendix A, July 1, 2002)

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
I.A.5	Puget Sound Clean Air Agency Order of Approval No. 7381, Condition 4	6/6/01	PM-10 emissions from each baghouse except the main stack baghouse, shall not exceed 0.005 grains /dscf over a 24 hour period.	II.A.1 General Opacity Monitoring	24 hours	EPA Methods 5 or 201A (40 CFR Part 60, Appendix A, July 1, 2002; 40 CFR Part 51, Appendix M, July 1, 2001)
SO_2 Standards						
I.A.6	Puget Sound Clean Air Agency Reg I: 9.07 WAC 173-400-040(6) first paragraph only.	04/14/94 09/20/93	Ash Grove shall not emit SO_2 in excess of 1,000 ppmv (dry) corrected to 7% O_2 for fuel burning equipment	No monitoring required	(3) 1-hour runs	EPA Method 6C (40 CFR Part 60, Appendix A, July 1, 2002)
Nuisance Standards						
I.A.7	Puget Sound Clean Air Agency Reg I: 9.11(a) (*State Only*) WAC 173-400-040(5) RCW 70.94.040 (*State Only*) WAC 173-400-040(2) *(State Only)*	03/11/99 09/20/93 1996 9/15/01	Ash Grove shall not emit air contaminants in sufficient quantities and of such characteristics and duration as is, or is likely to be, injurious to human health, plant or animal life, or property, or which unreasonably interferes with enjoyment of life and property Ash Grove shall not deposit particulate matter beyond property boundary in sufficient quantity to interfere unreasonably with the use and enjoyment of the property	II.A.2 Complaint Response II.A.3 Rooftop Inspections II.A.4 O&M Plan Inspections	NA	NA
I.A.8	WAC 173-400-040(4) *(State Only)*	9/15/01	Ash Grove shall use recognized good practice and procedures to reduce odors which may unreasonably interfere with any other property owners' use and enjoyment of their property	II.A.2 Complaint Response II.A.3 Rooftop Inspections	NA	NA

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
Fugitive Dust Standards						
I.A.9	**RESERVED**					
I.A.10	**RESERVED**					
I.A.11	WAC 173-400-040(3)(a) WAC 173-400-040(8)(a) *These requirements* shall *be superseded by the 9/15/02 versions of SIP WAC 173-400-040(3)&(8) upon adoption into the SIP* WAC 173-400-040(3)(a) *(State Only)* WAC 173-400-040(8)(a) *(State Only)* *These requirements will become federally enforceable upon adoption into the SIP and will replace the 9/20/93 versions of WAC 173-400-040(3)&(8)*	9/20/93 9/20/93 9/15/01 9/15/01	Ash Grove shall take reasonable precautions to prevent the release of fugitive emissions and to minimize emissions of fugitive dust.	II.A.3 Rooftop Inspections II.A.4 O&M Plan Inspections	NA	NA
I.A.12	**RESERVED**					
I.A.13	Puget Sound Clean Air Agency Reg. I: 9.15(a)	3/11/99	Ash Grove shall not cause or allow visible emissions of fugitive dust unless reasonable precautions are employed to minimize the emissions.	II.A.3 Rooftop Inspections II.A.4 O&M Plan Inspections	NA	NA

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
Operation and Maintenance Standards						
I.A.14	Puget Sound Clean Air Agency Reg. I: 9:20 RCW 70.94.152(7) (*State Only*)	6/09/88 1996	Ash Grove shall maintain equipment in good working order Equipment described in plans, specifications or other information submitted in support of a notice of construction application shall be maintained and operate in good working order	II.A.4 O&M Plan Inspections	NA	NA
I.A.15	Puget Sound Clean Air Agency Reg. I: 7.09(b)	9/12/96	Ash Grove shall develop and implement an O&M Plan to assure continuous compliance with Puget Sound Clean Air Agency Regulations I, II and III NOTE: See EU 1.31 for 40 CFR Part 63 O&M plan requirements for the kiln	II.A.4 O&M Plan Inspections	NA	NA
Emissions from common stack						
I.A.16	WAC 173-400-040	09/20/93	Emissions from a common stack must meet the most restrictive standard of any of the connected emissions units	No monitoring required	NA	NA
HCl Standards						
I.A.17	Puget Sound Clean Air Agency Reg. I: 9.10(a) *(State Only)*	06/09/88	Ash Grove shall not emit HCl in excess of 100 ppm (dry) corrected to 7% O_2 for combustion sources	No monitoring required	(3) 1-hour runs	EPA Method 26 or 26A (40 CFR Part 60, Appendix A; July 1, 2002)
I.A.18	**RESERVED**					

NA = Not Applicable

B. EMISSION UNIT SPECIFIC APPLICABLE REQUIREMENTS

The requirements in Section I.B. apply only to the specific emission units cited; however, the requirements in Section I.A. also apply to those units, except as otherwise provided in this section.

1. Emission Unit #1 (EU-1): Rotary Cement Kiln, Main Stack and Coal Mills

This emission unit consists of a nominal 2400 ton/day capacity rotary Portland cement kiln, primarily fired with coal and natural gas, and controlled by a nominal 177,000 acfm baghouse. The main stack emissions are monitored for opacity, carbon monoxide, nitrogen oxides and sulfur dioxide emissions by a continuous emission monitoring system. Fuels include bituminous coal, whole tires, a small amount of internally generated waste lubricating oils and greases, and natural gas. Dust entrained in the flue gases is collected in the Fuller Baghouse.

Although most of the kiln emissions exit from the kiln/raw mill through the main stack, a small portion of the hot kiln exhaust gases are routed directly from the kiln exhaust to the coal mills for use in thermally drying coal prior to grinding. Each coal mill is controlled by a nominal 10,400 acfm baghouse. This emission unit includes the coal mills because a small portion of kiln exhaust gases vent to the atmosphere through the coal mill baghouse stacks.

Emission Unit (EU-1)

Reqmt. No.	**Enforceable Requirement**	**Adoption or Effective Date**	**Requirement Paraphrase** (Information Only)	**Monitoring, Maintenance & Recordkeeping Method** (See Section II)	**Emission Standard Period**	**Reference Test Method**
Opacity Standards						
EU 1. 1	**RESERVED**					
EU 1. 2	Puget Sound Clean Air Agency Reg. I: 9.04(c)(2)	04/09/98	Ash Grove shall not cause or allow the emission of any air contaminant (as determined by the COMS) from the kiln stack during any hour that contains any consecutive 6-minute period averaging greater than 20% opacity.	II.B.1 Continuous Opacity Monitoring System	6-minute period	EPA Performance Specification 1 (40 CFR 60, Appendix B, July 1, 1997) EPA Method 9 (40 CFR 60, Appendix A, July 1, 2002.
EU 1. 3	**RESERVED**					

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 4	Puget Sound Clean Air Agency Reg. I: 9.04(c)(1)	04/09/98	Ash Grove shall not cause or allow the emission of any air contaminant (as determined by the COMS) from the kiln stack during any hour that averages greater than 5% opacity for a one hour average.	II.B.1 Continuous Opacity Monitoring System	1-hour average	EPA Performance Specification 1 (40 CFR 60, Appendix B, July 1, 1997) EPA Method 9 (40 CFR 60, Appendix A, July 1, 2002.
EU 1. 5	**RESERVED**					
EU 1. 6	**RESERVED**					
Puget Sound Clean Air Agency Orders of Approval NOC 5755 – Tire Derived Fuel						
EU 1. 7	Puget Sound Clean Air Agency Order of Approval No. 5755, Condition 4	3/30/95	Tire derived fuel substitutes shall be nonhazardous as defined by WAC 173-303-515 or WAC 173-303-090, as appropriate.	No monitoring required.	NA	NA
EU 1. 8	Puget Sound Clean Air Agency Order of Approval No. 5755, Condition 5	3/30/95	Daily weight of whole tires burned in the kiln shall not exceed 30 % of the total weight of fuels consumed in the kiln.	II.B.6 Tire Derived Fuel Consumption	Daily	NA
Puget Sound Clean Air Agency Order of Approval NOC 7381 and PSD Permit 90-03 -- Kiln BACT limits.						
EU 1. 9	Puget Sound Clean Air Agency Order of Approval No. 7381 Condition 5(a). PSD Permit 90-03, Amendment 3, Condition 3	6/06/01 10/08/01	CO emissions shall not exceed 1045 ppm at 10% O_2 for an 8-hour average. CO emissions shall not exceed 538 lbs/hour for an 8-hour average. CO shall not exceed 2353 tons per year including startup, shut down and malfunction periods.	II.B.2 SO2, CO and NOx CEMS II.B.3 SO2, CO and NOx Mass Emission Rate Monitoring	8 hours and annual	EPA Method 10 (40 CFR Part 60, Appendix A, July 1, 2002) EPA Performance Specification 4 (40 CFR Part 60, Appendix B, July 1, 1997)

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 10	Puget Sound Clean Air Agency Order of Approval No. 7381 Condition 5(b). PSD Permit 90-03, Amendment 3, Condition 1	6/06/01 10/08/01	NO_x emissions shall not exceed 650 ppm at 10% O_2 as a 24-hour rolling average. NO_x emissions shall not exceed 1846 tons as a 12-month running total including startup, shut down and malfunction periods. If NOx emissions exceed 1400 tons as a 12-month running total, Ash Grove shall notify the Puget Sound Clean Air Agency (Attn. Permit Certification) describing actions that will be implemented to assure compliance with the annual NOx limit.	II.B.2 SO2, CO and NOx CEMS II.B.3 SO2, CO and NOx Mass Emission Rate Monitoring	24-hours and annual	EPA Method 7E (40 CFR Part 60, Appendix A, July 1, 2002) EPA Performance Specification 2 (40 CFR 60, Appendix B, July 1, 1997)
EU 1. 11	Puget Sound Clean Air Agency Order of Approval No. 7381 Condition 5(c). PSD Permit 90-03, Amendment 3, Condition 2	6/06/01 10/08/01	Except during startup and shutdown of the kiln and scheduled maintenance SO_2 emissions from the main stack shall not exceed 180 ppm at 10% O_2 for a one-hr average. During startup following the introduction of feed to the kiln, SO_2 emissions from the main stack shall not exceed 200 ppm at 10% O_2 for a one-hr average. SO2 emissions shall not exceed 176 tons per year including startup, shut down and malfunction periods.	II.B.2 SO2, CO and NOx CEMS II.B.3 SO2, CO and NOx Mass Emission Rate Monitoring	One hour & annual	EPA Method 6C (40 CFR Part 60, Appendix A, July 1, 2002) EPA Performance Specification 2 (40 CFR 60, Appendix B, July 1, 1997)

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 12	Puget Sound Clean Air Agency Order of Approval No. 7381 Condition 6(a). PSD Permit 90-03, Amendment 3, Condition 2(c)	06/06/01 10/08/01	During kiln startup-preheat periods prior to feed introduction, shutdown and scheduled maintenance on the main baghouse the SO_2 emission limit for the main baghouse shall consist of compliance with the following work practices and fuel restrictions: (i) Only natural gas shall be used as fuel. (ii) Sulfur rings shall be removed from the Kiln prior to startup if sulfur rings formation had required the kiln to be shut down. (iii) Ash Grove shall follow the kiln startup and shutdown procedures in Appendix A to Order of Approval No. 7381.	II.B.8 Kiln Work Practice Monitoring	NA	NA
EU 1. 13	Puget Sound Clean Air Agency Order of Approval No. 7381 Condition 5(d).	06/06/01	Except during startup and shutdown of the kiln, scheduled maintenance and emissions considered unavoidable under WAC 173-400-107, PM emissions shall not exceed 10.6 pounds per hour.	II.B.9 PM Monitoring Main Baghouse	(3) 1-hour runs	Puget Sound Clean Air Agency Method 5 (See Section X)
EU 1. 14	Puget Sound Clean Air Agency Order of Approval No. 7381 Condition 5(d).	06/06/01	PM emissions shall not exceed 46 tons per year including startup, shut down and malfunction periods.	II.B.9 PM Monitoring Main Baghouse II.B.10 Production Rate Monitoring	annual	NA

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
40 CFR Part 60 Subpart F Standards of Performance for Portland Cement Plants						
EU 1. 15	40 CFR §60.62(a)(1) 40 CFR §60.8(c)	10/6/75 2/12/99	Kiln exhaust shall not exceed 0.30 lb of particulate per ton of feed (dry basis), except during SSM periods.	II.B.9 PM Monitoring Main Baghouse II.B.10 Production Rate Monitoring	(3) 1-hour runs	EPA Method 5 (40 CFR 60, Appendix A, July 1, 2002)
EU 1. 16	40 CFR §60.62(a)(2) 40 CFR 60.11(c)	10/6/75 10/17/00	Kiln exhaust shall not exceed 20 percent opacity, except during startup, shutdown and malfunction periods.	II.B.1 Opacity COMS	6 min. average	EPA Method 9 (40 CFR 60, Appendix A, July 1, 2002.
EU 1. 17	40 CFR §60.63(a)	12/14/88	Ash Grove shall record the daily production rates and kiln feed rates.	II.B.10 Production Rate Monitoring	NA	NA
40 CFR Part 60 Subpart Y Standards of Performance for Coal Preparation Facilities						
EU 1. 18	40 CFR 60.252(a)(1) 40 CFR §60.8(c)	10/17/00 2/12/99	Coal mill exhaust shall not exceed 0.031 gr/dscf, except during SSM periods.	II.A.1 General Opacity Monitoring	3 one-hour runs	EPA Method 5 (40 CFR 60, Appendix A, July 1, 2002)
EU 1. 19	40 CFR 60.252(a)(2) 40 CFR 60.11(c)	10/17/00 10/17/00	Coal mill exhaust shall not exceed 20 percent opacity except during SSM periods	II.A.1 General Opacity Monitoring	More than 6 min. in any 1 hr.	EPA Method 9 (40 CFR 60, Appendix A, July 1, 2002)
EU 1. 20	40 CFR 60.253(a)(1) and (b)	10/17/00	Ash Grove shall calibrate, maintain and continuously operate a temperature monitor at the inlet to each coal mill baghouse.	II.B.13 Temperature CMS	N/A	N/A/

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
40 CFR Part 63, Subparts A and LLL						
EU 1. 21	40 CFR §63.6(e)(1)	5/30/03	At all times, including periods of startup, shutdown, and malfunction, Ash Grove shall operate and maintain the kiln and raw mill, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. During an SSM period this general duty to minimize emissions requires that Ash Grove reduce emissions from the kiln and raw mill to the greatest extent which is consistent with safety and good air pollution control practices. The general duty to minimize emissions during an SSM event does not require Ash Grove to achieve emission levels required by Conditions EU 1.26 through 1.29 at other times if this is not consistent with safety and good air pollution control practices, nor does it require Ash Grove to make any further efforts to reduce emissions if levels required by Conditions EU 1.26 through 1.29 have been achieved.	II.B.14 Kiln Combustion System Inspections	N/A	N/A

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 22	40 CFR §63.6(e)(3)(i)	5/30/03	Ash Grove shall develop and implement a written startup, shutdown, and malfunction (SSM) plan that describes, in detail, procedures for operating and maintaining the kiln and raw mill during SSM periods, and a program of corrective action for malfunctioning process and air pollution control equipment used to comply with Subpart LLL standards. The SSM plan shall include the elements set forth in 40 CFR 63.6(e)(3).	II.D.8 NESHAP Subpart LLL Recordkeeping II.C.3 Immediate SSM Plan Deviation Report II.C.7 Semi-annual Subpart LLL SSM Plan Report	N/A	N/A
EU 1. 23	40 CFR 63.6(e)(3)(ii) 40 CFR 63.6(e)(1)(ii)	5/30/03 5/30/03	During SSM periods Ash Grove shall operate and maintain the kiln and raw mill (including associated air pollution control equipment) in accordance with the SSM plan. Malfunctions shall be corrected as soon as possible after their occurrence in accordance with the SSM plan	II.D.8 NESHAP Subpart LLL Recordkeeping II.C.3 Immediate SSM Plan Deviation Report II.C.7 Semi-annual Subpart LLL SSM Plan Report	N/A	N/A
EU 1. 24	40 CFR §63.6(e)(3)(vii)	5/30/03	Ash Grove shall change the SSM plan if required by the Puget Sound Clean Air Agency if it is determined to be unacceptable under §63.6(e)(2).	No monitoring required	N/A	N/A

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 25	40 CFR §63.6(e)(3)(viii)	5/30/03	Ash Grove shall update the SSM plan within 45 days of an SSM event that the plan failed to address or inadequately addressed. If Ash Grove makes SSM plan revisions which alter the scope of activities which are deemed a SSM or modifies the applicability of any limit or requirement under Subpart(s) A and LLL, the revisions shall not take effect until Ash Grove has provided written notification describing the revision to the Puget Sound Clean Air Agency.	No monitoring required	N/A	N/A
EU 1. 26	40 CFR §63.1343(d) 40 CFR §63.6(f)	6/14/99 5/30/03	Ash Grove shall not cause to be discharged into the atmosphere from the kiln exhaust Dioxin/furan (D/F) exceeding 0.20 ng/dscm ($8.7x10^{-11}$ gr/dscf)(TEQ) @ 7% O_2 when the baghouse inlet temperature is greater than 400º F, and 0.40 ng/dscm ($8.7x10^{-11}$ gr/dscf)(TEQ) @ 7% O_2 when the baghouse inlet temperature is equal to or less than 400º F. Standards apply at all times except during SSM periods.	II.B.13 Temperature CMS	(3) 3-hour runs	EPA Method 23 (40 CFR 60, Appendix A, July 1, 2002)

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 27	40 CFR §63.1343(d) 40 CFR §63.6(f)	6/14/99 5/30/03	Ash Grove shall not cause to be discharged into the atmosphere from either coal mill stack Dioxin/furan (D/F) exceeding 0.40 ng/dscm (8.7×10^{-11} gr/dscf)(TEQ) @ 7% O_2. Standards apply at all times except during SSM periods.	II.B.13 Temperature CMS	(3) 3-hour runs	EPA Method 23 (40 CFR 60, Appendix A, July 1, 2002)
EU 1. 28	40 CFR §63.1344(**a**) 40 CFR 63.6(f)	12/6/02 5/30/03	Ash Grove shall operate the kiln such that the temperature of the gas inlet to the kiln/raw mill baghouse does not exceed the applicable temperature limits established during a performance test for periods when the raw mill does and does not operate. (§63.1349(b)). Standards apply at all times except during SSM periods.	II.B.13 Temperature CMS	3-Hour Rolling Average	NIST Calibrated Reference Thermocouple – Potentiometer system
EU 1. 29	40 CFR §63.1344(**a**), as modified by 10/18/02 letter from Puget Sound Clean Air Agency to Robert Vantuyl establishing alternative monitoring methods for the coal mill 40 CFR 63.6(f)	12/6/02 5/30/03	Ash Grove shall operate the kiln such that the inlet temperature to each coal mill baghouse does not exceed 200 degrees F. Standards apply at all times except during SSM periods.	II.B.13 Temperature CMS	3-Hour Rolling Average	NIST Calibrated Reference Thermocouple – Potentiometer system

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 30	40 CFR 63.1349(b)(3) and (d); 10/18/02 letter from Puget Sound Clean Air Agency to Robert Vantuyl establishing alternative monitoring methods for the coal mill	12/6/02	Except as waived or modified pursuant to 40 CFR 63.7 or 63.8, every 30 months Ash Grove shall conduct a performance test on the kiln and the two coal mill baghouse exhaust vents for dioxin/furans, using test methods described in 40 CFR 63.1349(b)(3). In any performance test conducted on the coal mills, Ash Grove may measure dioxin/furan emissions from one of the two coal mills, but the flow rate shall be measured from both coal mills. The first such test shall occur no later than 30 months after the initial performance test performed on October 22-24, 2002.	II.C.8 Subpart LLL Performance Test Reporting II.D.8 NESHAP Subpart LLL Recordkeeping	(3) 3-hour runs	EPA Method 23 (40 CFR 60, Appendix A, July 1, 2002)

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 31	40 CFR 63.1349(e)(3)(i)	12/6/02	Provide Puget Sound Clean Air Agency written notice at least 60 days prior to undertaking any operational change that may adversely affect compliance with the D/F emission standards in Conditions EU 1.26 and 1.27, or as soon as practicable where 60 days advance notice is not feasible. Notice shall include a description of the planned change, the emissions standards that may be affected by the change, and a schedule for completion of the performance test required by Condition EU 1.32, including when the planned operational change would begin.	N/A	N/A	N/A

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 32	40 CFR 63.1349(b)(3) and (e)	12/6/02	Conduct a dioxin/furan performance test whenever Ash Grove plans to undertake a change in operations that may adversely affect compliance with the D/F emission standards in Conditions EU 1.26 or 1.27. In preparation for and while conducting the performance test, the kiln and raw mill may operate under the planned operational change conditions for a period not to exceed 360 hours, provided that Ash Grove notifies Puget Sound Clean Air Agency as described in Condition EU 1.31, that the performance test results are documented in a test report containing the information listed in 40 CFR 63.1349(a), and that a test plan is made available for Puget Sound Clean Air Agency review prior to testing, if requested. The performance test must be completed within 360 hours after the planned operational change begins. Ash Grove shall submit to Puget Sound Clean Air Agency temperature and other monitoring data recorded during any period of pretest operations.	II.C.8 Subpart LLL Performance Test Reporting II.D.8 NESHAP Subpart LLL Recordkeeping	(3) 3-hour runs	EPA Method 23 (40 CFR 60, Appendix A, July 1, 2002)

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 33	40 CFR 63.1349(e)(1)	12/6/02	Data collected during a performance test under Condition EU 1.32 shall be used to establish new temperature limits for the kiln, supplanting the limits established under 40 CFR 63.1349(b).	N/A	N/A	N/A
EU 1. 34	40 CFR 63.8(e); 40 CFR 63.9(g) 40 CFR 63.1353(b)(4) 40 CFR 63.10(e)(2) 40 CFR 63.1354(b)(6)	4/5/02 5/30/03 6/14/99 5/30/03 4/5/02	Ash Grove shall conduct a performance evaluation of the temperature CMS required by Conditions EU 1.29 and 1.30 whenever requested by EPA under Clean Air Act Section 114. Any performance evaluation shall be conducted in accordance with the requirements of 40 CFR 63.8(e). Notification of the performance evaluation shall be provided as required in 40 CFR 63.1353(b)(4). Results of the performance evaluation shall be reported as provided in 40 CFR 63.1354(b)(6).	N/A	N/A	N/A

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 1. 35	40 CFR §63.1350(a)-(b)	12/6/02	Ash Grove shall prepare for the kiln and raw mill an O&M plan including the following provisions: (a) Procedures for proper operation and maintenance of the kiln and associated air pollution control equipment to meet the dioxin/furan emission limits and parametric limits in conditions EU 1.26, 1.27 and 1.28; (b) Procedures to be used during an inspection of the components of the kiln and raw mill at least once per year. Failure to comply with those procedures shall be a violation of Subpart LLL. Ash Grove submitted the O&M plan for this requirement to the Puget Sound Clean Air Agency for approval on May 24, 2002. Ash Grove shall submit updates of the O & M Plan to the Agency upon adoption. Ash Grove may elect to integrate the Subpart LLL O&M Plan into the general O&M plan required by Condition I.A.15. If so the general O&M plan shall specifically identify those provisions required by this condition.	II.B.14 Kiln Combustion System Inspection II.D.8 NESHAP Subpart LLL Recordkeeping	NA	NA

Reqmt. No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
Puget Sound Clean Air Agency Order of Approval NOC 9229 **Burn Used Oils in Kiln**						
EU 1.36	Puget Sound Clean Air Agency Order of Approval No. 9229 Condition 3	05/17/2007	3. Ash Grove shall limit used oil to non-hazardous as defined by WAC 173-303-515, Special Requirements for Used Oil Burned for Energy Recovery, or by WAC 173-303-090, Dangerous Waste Characteristics. Ash Grove is authorized to burn used oils meeting the material specifications in EU 1.38.	II.B.5 Used Oil Monitoring	Daily	NA
EU 1.37	Puget Sound Clean Air Agency Order of Approval No. 9229 Condition 4	05/17/2007	4. Ash Grove shall limit the total amount of used oil injected into the kiln to 8640 gal/calendar day.	II.B.5 Used Oil Monitoring	Daily	NA
EU 1.38	Puget Sound Clean Air Agency Order of Approval No. 9229 Condition 5	05/17/2007	5. Ash Grove shall only burn used oils meeting the following limits as delivered: (a) As less than or equal to 5 ppm; (b) Cd less than or equal to 2 ppm; (c) Cr less than or equal to 10 ppm; (d) Pb less than or equal to 100 ppm; (e) PCB less than or equal to 50 ppm; (f) Total Halogens less than 1000 ppm; (g) Flash Point greater than or equal to 100°F; (h) Heat content between 5,000 Btu/lb & 19,000 Btu/lb.	II.B.5 Used Oil Monitoring	Daily	NA

N/A = Not Applicable. A specific reference test method and/or emission standard period is specified in the requirement. A test method is neither needed nor appropriate.

2. Emission Unit Group #2 (EU-2): Coal Processing, Storage and Transfer Facilities

This group consists of four coal storage, processing and transfer and loading systems that are subject to NSPS Subpart Y, Standards of Performance For Coal Preparation Plants. The affected facilities are Equipment Numbers 41B.FN1 (Coal Feeder #1), 41B.FN2 (Coal Feeder #2), 41A.BF3 (Raw Coal Silo), and 41C.BF1 (PF Bin). Subpart Y also regulates the #1 and #2 coal mills, but the applicable requirements for those units appear in Section I.B.1 above.

APPLICABLE REQUIREMENTS

Reqmt No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 2. 1	40 CFR §60.11(d)	10/17/00	At all times, including SSM periods Ash Grove shall to the extent practicable maintain and operate Subpart Y affected facilities including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.	I.A.4 O&M Plan Inspections	N/A	N/A
EU 2. 2	40 CFR 60.252(c) 40 CFR 60.11(c)	10/17/00 10/17/00	Exhaust gases shall not exceed 20 percent opacity except during SSM periods.	II.A.1 General Opacity Monitoring	6 minute average	EPA Method 9 (40 CFR 60, Appendix A, July 1, 2002) 40 CFR 60.254, 2/14/89

3. Emission Unit Group #3 (EU-3): Portland Cement NSPS Affected Facilities

This group consists of certain equipment subject to 40 CFR Part 60, Subpart F, the New Source Performance Standards for Portland Cement Plants. The affected facilities included in this group are Transfer Towers 2, 3, 5, 6, 7, 8 and 10A, Equipment Numbers 311.ST1 (Stacker), 311.RE1 (Reclaimer), 315.BN1 (Limestone Storage Bin), P11.TD (Truck Dump), 41B.SX1 (Raw Coal Storage Silos), 312.FA1 (Feeder), 312.7G1(Clay Storage Shed), 315.BN2 (Clay Storage Bin), 315.BN3 (Silica Storage Bin), 315.BN4 (Slag Storage Bin), 315.FA1 (Clay Apron Feeder), 411.SX1, 411.SX 2(Raw Meal Blending, 411.SX3, 411.SX4 (Raw Meal Storage Silos), 612.DM1 (Cement Storage Dome), 419.BC6 (Clinker Shed Tripper), 41G (Clinker Loadout Railcar) and 611.BK1 (Cement Loadout Bulk Bag). Subpart F also regulates the kiln and raw mill, but the Subpart F requirements for those units are set forth in Conditions EU 1.15, 1.16 and 1.17.

APPLICABLE REQUIREMENTS

Reqmt No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
EU 3. 1	40 CFR §60.11(d)	10/17/00	At all times, including SSM periods Ash Grove shall to the extent practicable maintain and operate Subpart F affected facilities including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.	I.A.4 O&M Plan Inspections	N/A	N/A
EU 3. 2	40 CFR 60.62(c) 40 CFR 60.11(c)	10/17/00 10/17/00	Exhaust gases shall not equal or exceed 10 percent opacity except during SSM periods.	II.A.1 General Opacity Monitoring	6 minute average	EPA Method 9 (40 CFR 60, Appendix A, July 1, 2002)

4. Emission Unit #4 (EU-4): Finish Mills

The two finish mills are each rated at 55 tons per hour, installed in 1968 and controlled by two nominal 77,000 acfm high efficiency separator baghouses and two nominal 20,000 acfm mill sweep baghouses..

The clinker from the kiln that is passed through the G-Cooler becomes processed in the ball mills by grinding with gypsum to form cement and sent to the cement silos for storage.

In addition to the applicable requirements listed in this section, the finish mills are subject to the plant-wide requirements in Section I.A.

APPLICABLE REQUIREMENTS

Reqmt No.	**Enforceable Requirement**	**Adoption or Effective Date**	**Requirement Paraphrase** (Information Only)	**Monitoring, Maintenance & Recordkeeping Method** (See Section II)	**Emission Standard Period**	**Reference Test Method**
Puget Sound Clean Air Agency Orders of Approval NOC 5276						
EU 4. 1	Puget Sound Clean Air Agency Order of Approval No. 5276 Condition 4.	1/19/94	Ash Grove shall not allow particulate emissions from the (2) mill sweep baghouses to exceed 0.01 gr/dscf.	II.B.4 Finish Mill Baghouse Monitoring.	Average of 3 three-hour runs	Puget Sound Clean Air Agency Method 5 (See Section X)
EU 4. 2	Puget Sound Clean Air Agency Order of Approval No. 5276 Condition 6.	1/19/94	Ash Grove shall not allow particulate emissions from the (2) mill sweep baghouses to exceed 10% opacity.	II.B.4 Finish Mill Baghouse Monitoring.	More than 3 min. in any 1 hr	Ecology Method 9A (See Section X)

5. Emission Unit #5 (EU-5): Cement Dome & Steel Scale Tanks

The Cement Storage Dome is a 45,000 ton finished product storage facility controlled by a 6000 acfm Alanco baghouse. The Dome was installed in 1998. The four steel scale tanks are finished product loading facilities, used to load cement into trucks or railcars. The tanks were installed prior to 1971, but in 1998 Ash Grove replaced one of two baghouses that control emissions from the tanks with a new 6000 acfm Alanco baghouse. NOC 7242 approves construction of the Cement Storage Dome and the two Alanco baghouses.

In addition to the applicable requirements listed in this section, the Cement Storage Dome is subject to the plant-wide requirements listed in Section I.A and to the NSPS Subpart F requirements listed in Section I.B.3 of the permit. The Steel Scale Tanks are not Subpart F affected facilities.

APPLICABLE REQUIREMENTS

Reqmt No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
Puget Sound Clean Air Agency Orders of Approval NOC 7242 - Cement Storage Dome						
EU 5. 1	Puget Sound Clean Air Agency Order of Approval No. 7242, Condition 7	1/06/98	Ash Grove shall not allow PM-10 emissions from the Alanco baghouses mounted on the cement storage dome and the steel scale tanks to exceed 0.005 grains/dscf over a twenty-four hour period.	II.A.1 General Opacity Monitoring II.B.7 Cement Storage Dome Monitoring	Source test for a 24 hr period	Particulate by EPA Method 5 or EPA Method 201A (40 CFR Part 60, Appendix A, July 1, 2002; 40 CFR Part 51, Appendix M, July 1, 2001)

6. Emission Unit #6 (EU-6): Bulk Bag Loading Station

Bulk Bag Loading Station controlled with a 500 cfm baghouse. In addition to the applicable requirements listed in this section, the Bulk Bag Loading Station is subject to the plant-wide requirements listed in Section I.A and to the NSPS Subpart F requirements listed in Section I.B.3 of the permit.

APPLICABLE REQUIREMENTS

Reqmt No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
Puget Sound Clean Air Agency Orders of Approval NOC 8318 – Bulk Loading Station						
EU-6.1	Puget Sound Clean Air Agency Order of Approval No. 8318 Condition 3.	1/8/01	Ash Grove shall allow no visible emissions or fallout from the 500 cfm baghouse controlling the bulk bag loading station.	II.B.11 Bulk Bag Loading Station Monitoring	NA	NA
EU 6. 2	Puget Sound Clean Air Agency Order of Approval No. 8318 Condition 5.	1/8/01	If visible emissions, abnormal pressure drop or fallout are observed Ash Grove shall investigate the cause and either initiate repairs or shut down the equipment vented to the baghouse within 24 hours of the observation.	II.B.11 Bulk Bag Loading Station Monitoring	NA	NA

7. Emission Unit #7 (EU-7): Clinker Storage Shed

In addition to the applicable requirements listed in this section, the Clinker Storage Shed is subject to the plant-wide requirements listed in Section I.A.

APPLICABLE REQUIREMENTS

Reqmt No.	**Enforceable Requirement**	**Adoption or Effective Date**	**Requirement Paraphrase** (Information Only)	**Monitoring, Maintenance & Recordkeeping Method** (See Section II)	**Emission Standard Period**	**Reference Test Method**
Puget Sound Clean Air Agency Orders of Approval NOC 8600 – Clinker Storage Shed						
EU-7.1	Puget Sound Clean Air Agency Order of Approval No. 8600 Condition 3.	2/8/02	Ash Grove shall not allow the PM-10 emissions from the Pulse Jet R-08-88-81 baghouse to exceed 0.005 grains/dscf over a twenty-four hour period.	II.A1 General Opacity Monitoring	Source test for a 24 hr period	Particulate by EPA Method 5 or EPA Method 201A (40 CFR Part 60, Appendix A, July 1, 2002; 40 CFR Part 51, Appendix M, July 1, 2001)

8. Emission Unit #8 (EU-8): Group II Cement Silos

In addition to the applicable requirements listed in this section, the Group II Silos are subject to the plant-wide requirements listed in Section I.A.

APPLICABLE REQUIREMENTS

Reqmt No.	Enforceable Requirement	Adoption or Effective Date	Requirement Paraphrase (Information Only)	Monitoring, Maintenance & Recordkeeping Method (See Section II)	Emission Standard Period	Reference Test Method
Puget Sound Clean Air Agency Orders of Approval NOC 8643 – Group II Silos						
EU-8.1	Puget Sound Clean Air Agency Order of Approval No. 8643 Condition 3.	2/8/02	Ash Grove shall not allow the PM-10 emissions from each of the Pulse Jet Dust Collectors to exceed 0.005 grains/dscf over a twenty-four hour period.	II.A.1 General Opacity Monitoring	Source test for a 24 hr period	Particulate by EPA Method 5 or EPA Method 201A (40 CFR Part 60, Appendix A, July 1, 2002; 40 CFR Part 51, Appendix M, July 1, 2001)

II. MONITORING, REPORTING AND RECORDKEEPING METHODS

A. Facility Wide Monitoring Methods

1. General Opacity Monitoring

Ash Grove shall conduct monthly inspections of the facility for visible emissions. Inspections are to be performed while the equipment is in operation during daylight hours. If, during the scheduled inspection or at any other time, visible emissions other than uncombined water are observed, Ash Grove shall, as soon as possible, but no later than 24 hours after the initial observation, take corrective action until there are no visible emissions, shut down the unit or activity until it can be repaired or conduct a reference method opacity observation. If a reference method opacity observation reveals an exceedance of the applicable visible emissions limit, report the observation as a deviation and shut the unit down until repairs are complete and a non-reference method visible emissions observation reveals no visible emissions. Report deviations as provided in Condition II.C.2. Maintain records as provided in Conditions II.D.1 and II.D.5.

[Order of Approval No. 7381, Condition 4 (6/6/01); WAC 173-401-615(1), 10/17/02]

2. Complaint Response

Ash Grove shall develop and implement an Air Pollution Complaint Response Program as part of the O&M Plan required by Regulation I Section 7.09(b). The Complaint Response Program shall be annually reviewed and updated along with the O&M Plan. This Program shall include:

- An Ash Grove local contact person and a 24-hour telephone number;
- Complaint forms available to the public;
- Criteria and methods for establishing whether Ash Grove may be the source of fugitive dust or other air contaminant impacts on neighboring property;
- Format of communicating results of investigations and advising complainants of Ash Grove's corrective actions and preventive maintenance;
- Ash Grove shall record air pollution complaints (including those forwarded to Ash Grove from this Agency) and findings of investigations as provided in Condition II.D.6. Investigations shall be initiated within 1 day of receipt of a complaint on Ash Grove’s 24 hour complaint reporting phone line. Ash Grove’s Complaint Response Program shall describe the procedures for investigating complaints. Complaint investigation procedures shall include efforts to contact the complainant, to inspect the conditions described in the complaint, to determine whether Seattle plant sustained a malfunction or other operating or site conditions that might have generated abnormal levels of fugitive emissions, and to determine the wind speed, direction and/or other meteorological conditions during relevant times preceding receipt of the complaint.

If Ash Grove determines that emissions from its plant unreasonably impacted neighboring properties Ash Grove shall either eliminate the problem within 24 hours of identification or report a deviation as provided in Condition II.C.2. Ash Grove also shall report as a deviation any failure to initiate investigation of a complaint within 1 day of receipt of the complaint. Results of complaint investigations shall be reported monthly as provided in Condition II.C.10. Maintain records as provided in Condition II.D.6.

[WAC 173-401-615(1), 10/17/02]

3. Roof Top Inspections

Ash Grove shall conduct a roof-top[1] inspection at least weekly. These inspections shall include inspection for odor-bearing contaminants and for fugitive emissions from any part of the facility. In the event any fugitive emission release is discovered by an inspection, Ash Grove shall as soon as possible, but no later than 24 hours after discovered, begin corrective action, shut the operation down until the problem can be corrected, or report the release as a deviation as provided in Condition II.C.2. Ash Grove shall document each inspection as provided in Condition II.D.5.

[WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02]

4. O & M Plan Inspections

Ash Grove shall conduct a facility wide equipment inspection at least monthly. These inspections shall include:

- checking for prohibited activities under Section III of the permit and activities that require additional approval under Section IV of the permit
- inspection for proper operation of equipment and control equipment
- inspection for evidence that fugitive dust control measures required by Section 9.15 of Regulation I are being implemented
- inspection for odor bearing contaminant emissions from the facility.

In the event any violation of the underlying applicable requirement(s) are discovered by an inspection, Ash Grove shall as soon as possible, but no later than 24 hours after discovered, begin corrective action, shut the operation down until the problem can be corrected, or report the violation as a deviation under Condition II.C.2.

Ash Grove shall document all inspections required by this condition as provided in Condition II.D.5.

[Puget Sound Clean Air Agency Regulation I, Section 7.09(b) (9/10/1998); WAC 173-401-615(1) (10/17/02)].

[1] *A "roof-top inspection" is a visual inspection of the overall facility from a sufficient height to allow the determination of the point(s) of origin and possibly the cause(s) of fugitive emissions.*

B. Source Specific Monitoring Methods

1. Continuous Opacity Monitoring System

i. Continuous Monitoring. Ash Grove shall install, calibrate, maintain and operate, in accordance with 40 CFR 60.13, a continuous opacity monitoring system (COMS) on the main kiln stack.

ii. Data Recovery. Ash Grove shall recover valid hourly monitoring data for at least 95% of the hours that the kiln operates during each calendar month except for periods of monitoring system downtime, provided that Ash Grove demonstrates to the Control Officer that the downtime was not a result of inadequate design, operation, or maintenance, or any other reasonably preventable condition, and any necessary repairs to the monitoring system are conducted in a timely manner.

iii. Quality Assurance. The COMS shall meet Performance Specification 1 in 40 CFR Part 60, Appendix B (1992), and Ash Grove shall operate this monitoring system in accordance with the U.S. Environmental Protection Agency's "Recommended Quality Assurance Procedures for Opacity Continuous Monitoring Systems" (EPA 340/1-86-010).

iv. Data Recording. Monitoring data commencing on the clock hour and containing at least 45 minutes of monitoring data shall be reduced to 1-hour averages. Monitoring data for opacity shall also be reduced to 6-minute averages. All monitoring data shall be included in these averages except for data collected during calibration drift tests and for data collected subsequent to a failed quality assurance test or audit.

v. Relative Accuracy Tests. All relative accuracy tests shall be subject to the provisions of Regulation I, Section 3.07 (2/9/95).

vi. Reporting and Recordkeeping. Report as provided in Conditions II.C.4, II.C.5, II.C.11 and/or II.C.12 (where applicable) each occasion on which the COMS records a violation of applicable opacity limit(s), or on which the COMS sustains an unexcused failure to meet the data recovery requirements of this condition. Maintain records as required in Section II.D.

[WAC 173-401-615(1) (10/17/02); 40 CFR 60.63(b) (12/14/88); 40 CFR 60.13(a), (d) - (f) and (h) (8/27/01); Order of Approval 7381, Condition 7 (6/6/01); Puget Sound Clean Air Agency Regulation I, Section 12.01 & 12.03 (4/9/98)]

2. SO2, CO and NOx Continuous Emissions Monitoring System

i. Continuous Monitoring. Ash Grove shall operate a continuous emission monitoring system (CEMS) for SO2, CO and NOx for the kiln main stack.

ii. Data Recovery. Ash Grove shall recover valid hourly monitoring data for at least 95% of the hours that the kiln is operated during each calendar month except for periods of monitoring system downtime, provided that Ash Grove demonstrates to the Control Officer that the downtime was not a result of inadequate design, operation, or maintenance, or any other reasonably preventable condition, and any necessary repairs to the monitoring system are conducted in a timely manner.

iii. Quality Assurance. The CEMS for each pollutant shall meet the relevant performance specification in 40 CFR Part 60, Appendix B (1990), and Ash Grove shall operate this monitoring system in accordance with the quality assurance procedures in 40 CFR Part 60, Appendix F in effect July 1, 1992.

iv. Data Recording. Monitoring data commencing on the clock hour and containing at least 45 minutes of monitoring data shall be reduced to 1-hour averages. All monitoring data shall be included in these averages except for data collected during calibration drift tests and for data collected subsequent to a failed quality assurance test or audit.

v Relative Accuracy Tests. All relative accuracy tests shall be subject to the provisions of Regulation I, Section 3.07 (2/9/95).

vi. Reporting. Report as provided in Condition II.C.4 each occasion on which the CEMS records a violation of applicable emission limit(s), or on which the CEMS sustains an unexcused failure to meet the data recovery requirements of this condition. Maintain records as provided in Condition II.D.1.

vii. Data Retention. See Condition II.D.3.

[WAC 173-401-615(1) (10/17/02); Order of Approval 7381, Condition 7 (6/6/01); PSD Permit 90-03, Amendment 3, Condition 7 (10/8/01); Puget Sound Clean Air Agency Regulation I, Section 12.01 & 12.03 (4/9/98)]

3. SO2, CO, and NOx Mass Emission Rate Monitoring

Ash Grove shall calculate emissions of SO2 and CO from the cement kiln operation on a calendar year basis, and NOx emissions from the cement kiln operation on a 12-month rolling total basis, using the CEMS data collected under the requirements of Section II.B.2 of this permit. Additionally, Ash Grove shall calculate the 8-hour block average mass emission rate for CO using CEMS data collected under the requirements of Section II.B.2 of this permit. Each day shall consist of three 8-hour CO compliance intervals, the first interval commencing at 12:00 AM. When CEM data is not available or not required to be collected as identified by this permit, other information available to Ash Grove shall be used to compile the emission rate values. Report deviations as provided in Condition II.C.4. Maintain records as provided in Condition II.D.10.

[WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02] [Order of Approval No. 7381, Condition 7, 6/6/01; PSD Permit 90-03, Amendment 3, Conditions 1-3, 10/8//01]

4. Finish Mill Baghouse Monitoring

Ash Grove shall monthly measure and record the pressure drop across the 20,000 cfm mill sweep baghouses. If a measurement reveals a pressure drop reading outside the range of 3 to 6 inches, take corrective action as soon as possible, but no later than 24 hours after the initial observation. If, following corrective action, the pressure drop remains outside the range of 3 to 6 inches, either shut down the unit until it can be repaired, or report the reading as a deviation. Keep a log of pressure drop readings, and of any corrective action taken. Document all measurements and actions required by this condition as provided in Condition II.D.1. Report any deviation as provided in Condition II.C.2.

[Order of Approval 5276, Condition No. 7 (1/19/94); WAC 173-401-615(1) and WAC 173-401-615(2), (10/17/02)]

5. Used Oil Monitoring

(a) Ash Grove shall monitor and maintain daily records of the volume of used oil injected into the kiln. Ash Grove shall submit these records on a monthly basis with the required CEMS reports as provided in Condition II.C.4. Examples of used oil include:

- (i) Used oils;
- (ii) Refined oil tank bottoms;
- (iii) Raw crude tank bottoms;
- (iv) Heavy vacuum gas oil waste;
- (v) Off specification fuel oil.

(b) Ash Grove shall:

- (i) Authorize the person receiving and reviewing used oil shipments the authority to reject materials exceeding limits in EU 1.36 and EU 1.38.
- (ii) Obtain a signed laboratory report from the oil supplier verifying each shipment of used oil received meets the limits in EU 1.38.
- (iii) Maintain a used oil delivery log and record in this log the name of the supplier, the delivery date, the volume of used oil and a signed laboratory report of each shipment of used oil received.

(c) Ash Grove shall calibrate the used oil flow meter at least once per calendar year. and maintain records for that calibration.

(d) Ash Grove shall report any deviation as provided in Condition II.C.2 and shall maintain records described above in accordance with Condition II.D.3ast once per calendar year. and maintain records for that calibration in accordance with Condition II.D.3.

[Order of Approval No.9229, Conditions No. 4, 6, and 7 (05/17/2007)]

6. Tire Derived Fuel Consumption

Ash Grove shall monitor the weight of whole tires injected into the kiln following the Fuel Monitoring Plan required by Order of Approval 5755, Condition 6. Report a deviation per Condition II.C.2 if the daily weight of whole tires injected during each calendar day (7 am to 7 am) exceeds 30 percent of the weight of all fuels consumed in the kiln during that day. Report the daily weight of whole tires injected per Condition II.C.11.

[Order of Approval 5755, Condition No. 6 (1/11/95); WAC 173-401-615(1) and WAC 173-401-615(2) (10/17/02)]

7. Cement Storage Dome Monitoring

Ash Grove shall install and maintain gauges to monitor the pressure drop across each of the two Alanco Baghouse exhaust filters. The acceptable ranges for the gauges shall be clearly marked on or near the gauges. Once during each shift that either Alanco baghouse is used, record the pressure drop across the exhaust filter of that baghouse. If the pressure drop falls outside the acceptable range, take corrective action as specified in the facility's O & M plan. If, following corrective action, the pressure drop remains outside the acceptable range, either shut down the unit until it can be repaired, or report the reading as a deviation. Keep a log of pressure drop readings, and of any corrective action taken Report deviations as provided in Condition II.C.2.

[Order of Approval 7242, Condition No. 4 - 6 (1/06/98); WAC 173-401-615(1) and WAC 173-401-615(2) (10/17/02)]

8. Kiln Work Practice Monitoring

Ash Grove shall log as part of the O & M Plan the following activities:

(i) The date, start and end times, and the fuels used for kiln startup-preheat periods prior to feed introduction;

(ii) The date and time of sulfur ring removal from the kiln, if the ring formation required the kiln to be shut down;

(iii) The date, start and end times for kiln startup-feed introduction periods; and

(iv) The cause for kiln shut down, the duration of kiln cool down and the kiln rotation schedule in kiln cool down.

Report as provided in Condition II.C.4 the information described above. Report as a deviation any unexcused departure from the startup and shutdown work practice requirements of Order of Approval 7381, Conditions 6(a) and (c) Maintain records as provided in Condition II.D.5.

[Order of Approval 7381, Condition 6 (6/06/01); WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02]

9. PM Monitoring Main Baghouse

(a) Conduct a Puget Sound Clean Air Agency Method 5 source test at least once per permit cycle, no later than 12 months prior to the expiration date of this permit. Report per Condition II.C.1 any exceedance of the underlying PM limit. Maintain records as provided in Condition II.D.1.

(b) Multiply the calendar year tonnage of clinker production by an emission factor of 0.0414 kg/Mg to determine annual PM10 emissions. Revise this emission factor using data from the most recent PM source test, provided that the test yields data deemed representative of the kiln baghouse emission rate. Use the revised emission factor to calculate annual emissions for years subsequent to the date of the source test. Record in a log the annual tonnage of clinker production. Report per Condition II.C.2 if calendar year PM emissions exceed 46 tons per year.

[Order of Approval 7381, Condition 5 (6/06/01); WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02]

10. Production Rate Monitoring

Record on a daily basis kiln production rate and kiln feed rate. Records may be maintained in electronic format. Report per Condition II.C.2 any failure to maintain the records required by this condition.

[40 CFR 60.63(a) (12/14/88); WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02]

11. Bulk Bag Loading Station Monitoring

At least once a week when the bulk loading station is in operation, Ash Grove shall inspect the dust collector for visible emissions, fallout and pressure drop across the filters. Record the time and results of each inspection. If visible emissions, fallout or abnormal pressure drop are observed, initiate corrective action within 24 hours or shut down the equipment vented to the baghouse within 24 hours. If, following corrective action, the problem remains, either shut down the unit until it can be repaired, or report the observation as a deviation as provided in Condition II.C.2. Keep a log of inspections and of any corrective action taken.

[Order of Approval 8318, Conditions 4-6 (1/08/01); WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02]

12. Used Oil Source Testing

(a) Ash Grove shall submit a source test plan no later than 30 days after the completion date specified in the Notice of Completion submitted for Order of Approval 9229. The source test plan shall meet the requirements of Puget Sound Clean Air Agency Regulation I, Section 3.07 for test parameters specified below. For the dioxin/furan testing, Ash Grove shall also follow 40 CFR 63, Subparts A and Subpart LLL, including determining the average inlet temperature of the particulate matter control device following. Alternative test methods to those identified in II.B.12(b) may be used only after review and approval by the Agency.

(b) Ash Grove shall complete performance source testing while operating with and without the injection of used oil. These tests shall be conducted while burning coal but not injecting tires and with the raw mill both operating and not operating. All tests shall be performed no later than 90 days after the completion date specified in the Notice of Completion submitted for Order of Approval No. 9229 and shall use the following methods:

- (i) Opacity (CEMS);
- (ii) SO2 (CEMS);
- (iii) NOx (CEMS);
- (iv) CO (CEMS);
- (v) Formaldehyde (Method 0011/SW-8315);
- (vi) HCl (EPA Method 26A);
- (vii) Metals (EPA Method 29);

(viii) Dioxin/Furan (EPA Method 23).

(c) During the performance source testing, Ash Grove shall record the following data:

(i) Main Baghouse inlet temperature following 40 CFR 63.1349(b)(3);
(ii) Type and quantity of clinker manufactured for cement;
(iii) Type and quantity of raw materials added to kiln;
(iv) Type, quantity and fuel Btu added to the kiln (including used oil);
(v) Burnability Index; and
(vi) Variability of raw mix.

(d) Ash Grove shall report the results of the performance source test per Conditions II.C.8 and V.N.

[Order of Approval No. 9229, Conditions 8, 9, and 10 (05/17/2007)]

13. Temperature CMS

Ash Grove shall install, calibrate, maintain and continuously operate a continuous temperature monitor system (CMS) at the kiln baghouse inlet and at the inlet to each coal mill baghouse. Each CMS shall meet performance specifications in 40 CFR 63.1350(f) (4/5/02). Each CMS shall meet the O & M and data availability requirements of 40 CFR 63.8(c), (d) and (e). The calibration of the CMS shall be verified at least once every three months. Ash Grove shall continuously record inlet temperatures at the kiln and coal mill baghouses as provided in § 63.1350(f). Maintain records as provided in Conditions II.D.7 and II.D.8. Report as provided in Conditions II.C.6 and/or II.C.12 .

[40 CFR 60.253(a)(1) and (b) (10/17/00); 40 CFR 63.1350(f) (12/6/02); 40 CFR 63.8 (4/5/02); 40 CFR 63.10(b)(2)(vi) (5/30/03); WAC 173-401-615(1) (10/17/02)].

14. Kiln Combustion System Inspections

Ash Grove shall inspect the components of the kiln combustion system once per year for compliance with those provisions of the O&M Plan that ensure compliance with the dioxin/furan emission limits in Conditions EU 1.27 and 1.28. Maintain records as provided in Condition II.D.8. Report as provided in Condition II.C.6.

[40 CFR 63.1350(i) (12/6/02); 40 CFR 63.1354(a)(9)(iv) (6/14/99); WAC 173-401-615(1) and WAC 173-401-615(2), 10/17/02]

C. Reporting

Ash Grove shall file the following reports with the Puget Sound Clean Air Agency on the schedules provided herein.

1. General Reporting

Any monitoring reports required by this permit shall be submitted to Puget Sound Clean Air Agency Operating Permit Certification at least once every six months, or more frequently where specified in the permit. All instances of deviations from permit requirements must be clearly identified in such reports. All reports must be certified by the responsible official consistent with Condition V.Q. Where an applicable requirement requires reporting more frequently than once every six months, the responsible official's certification needs to only be submitted once every six months, covering all required reporting since the date of the last certification, provided that the certification specifically identifies all documents subject to certification.

[WAC 173-401-615(3)(a) (10/17/02)]

2. General Deviation Reporting

Ash Grove shall report in writing to Puget Sound Clean Air Agency Operating Permit Certification all instances of deviations from permit requirements, including those attributable to upset conditions as defined in this permit, the probable cause of the deviations, and any corrective actions taken. Ash Grove shall maintain a contemporaneous record of all deviations. Ash Grove shall report any deviations that represent a potential threat to human health or safety by FAX (206 343-7522) as soon as possible but no later than 12 hours after such a deviation is discovered. Ash Grove shall report other deviations in writing to Puget Sound Clean Air Agency Operating Permit Certification no later than 30 days after the end of the month during which the deviation is discovered. Deviations revealed by a continuous monitoring system shall be reported as provided in Condition II.C.4 or Condition II.C.11

[WAC 173-401-615(3)(b) (10/17/02)]

3. Immediate Subpart LLL SSM Plan Deviation Report

Any time an action taken by Ash Grove during an SSM event (including actions taken to correct a malfunction) is not consistent with the procedures in Ash Grove's Subpart LLL SSM Plan, and the kiln exceeds an emission limit in Conditions EU1.26 or 1.28, Ash Grove shall report the actions taken for that event to Puget Sound Clean Air Agency by telephone or facsimile transmission within 2 working days after commencing actions inconsistent with the plan. That immediate report shall be followed by a letter delivered or postmarked within 7 working days after the end of the event, explaining the circumstances of the event, the reasons for not following the plan, and describing all Subpart LLL excess emissions and/or parameter monitoring exceedances are believed to have occurred. The letter must contain the name, title and signature of the responsible official who certifies its accuracy.

[40 CFR 63.10(d)(5)(ii) (5/30/03); 40 CFR 63.1354(b)(5) (6/14/99); WAC 173-401-615(3) (10/17/02)]

4. Monthly CEM Report

Ash Grove shall file with Puget Sound Clean Air Agency a monthly CEM report, which shall be delivered or postmarked within 30 days after the end of the month in which the data were recorded. This report shall include:

a. The date, time period, magnitude and cause of each emission of opacity, CO, NOx and SO2 recorded by the kiln CEMS that exceeded applicable emission limits for that parameter;

b. The date and time of all actions taken to correct the problem, including any actions taken to minimize emissions during the exceedance and any actions taken to prevent its recurrence;

c. The number of hours that the kiln operated each month and the number of valid hours of monitoring data for each parameter that the respective CEMS recovered that month;

d. The date, time period and cause of each failure to meet the data recovery requirements of Puget Sound Clean Air Agency Regulation I, § 12.03(b), and any actions taken to ensure adequate collection of such data;

e. The date, time period and cause of each failure to recover valid hourly monitoring data for at least 90% of the hours that the kiln operated each day;

f. The results of all cylinder gas audits conducted during the month.

g. Demonstrations required under WAC 173-400-107 (4), (5) or (6) for exceedances deemed by Ash Grove to be "unavoidable."

h. The date and time of commencement of each startup preheat, each introduction of feed to the kiln, the completion of startup and each shutdown of the kiln.

i. The Complaint Response Report required by Condition II.C.10 shall be included as an attachment to the monthly CEM Report.

j. The monthly CEM reports for June and December shall include, as attachments, the reports required by Conditions II.C.5, II.C.6, and II.C.7.

k. The daily used oil consumption in gallons for each day of the month.

[PSD Permit 90-03, Amendment 3, Conditions 8 and 9 (10/8/01); Order of Approval 7381, Condition 7 (6/6/01); Puget Sound Clean Air Agency Reg. I: 12.03(f) (4/9/98); WAC 173-401-615(3) (10/17/02); Order of Approval No. 9229, Conditions No. 4 (05/17/2007)]

5. Semi-annual NSPS Report

The monthly CEM reports filed for the months of June and December shall include a semi-annual NSPS Subpart F excess emissions and monitoring system performance report, reporting data from the kiln COMS for the six month reporting periods ending June 30 and December 31. For purposes of those reports, "excess emissions" means all 6 minute periods during which the average opacity measured by the kiln COMS exceeds 20 percent. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and COMS downtime for the reporting period is less than 5 percent of the total operating time for the period, Ash Grove need submit only a Summary Report in the format shown in Section X.E below. If the total duration of excess emissions for the reporting period equals 1 percent or greater of the total operating time for the reporting period or total COMS downtime for the reporting period is 5 percent or greater of the total operating time for the period, Ash Grove shall submit both the Summary Report and an Excess Emissions Report containing the following information for kiln opacity excess emissions:

a. The magnitude of excess emissions, computed in accordance with 40 CFR 60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

b. The process operating time during the reporting period;

c. Specific identification of each period of excess emissions that occurs during startups, shutdowns and malfunctions of the kiln, the nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted;

d. The date and time identifying each period during which the COMS was inoperative except for zero and span checks and the nature of the system repairs or adjustments;

When no excess emissions have occurred or the COMS has not been inoperative, repaired or adjusted, such information shall be stated in the report.

The semi-annual NSPS report shall be submitted to both the Puget Sound Clean Air Agency and EPA Region 10.

[40 CFR 60.7(c) and (d) (2/12/99); 40 CFR 60.65(a) (12/14/88); 40 CFR 60.63(d) 12/14/88); WAC 173-401-615(3) (10/17/02)]

6. Semi-annual NESHAP Subpart LLL Summary Report

The monthly CEM reports filed for the months of June and December shall include a semi-annual NESHAP Subpart LLL summary report for the six month reporting periods ending June 30 and December 31. The report shall be entitled: "Gaseous Excess Emission and Continuous Monitoring System Performance." It shall contain the following information:

a. Company name and address of the Seattle plant;

b. Statement that Ash Grove monitors kiln and coal mill baghouse inlet temperature as a parametric indicator of dioxin/furan emissions;

c. Beginning and ending dates of the reporting period;

d. Brief description of the kiln and in line raw mill;

e. Description of the temperature limits in Conditions EU 1.29 and 1.30;

f. Description of the manufacturer and model number(s) of the temperature monitor systems installed on the kiln and coal mills;

g. Date of the most recent temperature CMS certification or audit;

h. Total operating time of the kiln and raw mill during the reporting period;

i. Performance summary, including each three hour period during the reporting period in which the average temperature of the kiln and/or each of the coal mills exceeded the respective temperature limits for those units as set forth in Conditions EU 1.29 and 1.30, the total duration of excess emissions expressed as a percent of the total kiln and/or coal mill operating time during the reporting period, and a breakdown of the total duration of excess emissions into those that are due to startup, shutdown, control equipment problems, process problems, other known causes and unknown causes;

j. CMS performance summary for each temperature monitor, including the total number of hours of CMS downtime during the reporting period, total duration of CMS downtime expressed as a percent of the total kiln or coal mill operating hours during the reporting period, and a breakdown of total CMS downtime during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, QA/QC calibrations, other known causes, and unknown causes.

k. Description of any changes in any CMS, processes or controls since the last reporting period;

l. All failures to calibrate thermocouples and temperature sensors as required by Condition EU 1.20 and 40 CFR 63.1350(f)(6) (4/5/02)

m. Results of any combustion system component inspections conducted in the reporting period as provided in Condition II.B.13;

n. All failures to comply with any provision of the O&M plan developed in accordance with Condition EU 1.35;

o. Name, title and signature of the responsible official who certifies the accuracy of the report;

p. Date of the report.

If the total temperature CMS downtime for the reporting period for the kiln baghouse inlet CMS or either coal mill baghouse inlet CMS is ten percent or greater of the total operating time for the monitored unit during the reporting period, Ash Grove shall submit an excess emissions and continuous monitoring system report in addition to the summary report described in this condition.

[40 CFR 63.10(e)(3)(v)-(viii) (5/30/03); 40 CFR 63.1354(b)(8)-(10) (6/19/99); WAC 173-401-615(3) (10/17/02)]

7. Semi-annual Subpart LLL Startup Shutdown and Malfunction Report

The monthly CEM reports for June and December shall include, as an attachment, a semi-annual Subpart LLL SSM report. If actions taken by Ash Grove during SSM events occurring between January 1 and June 30 of each year were consistent with the procedures in Ash Grove's SSM plan, the SSM report for the month of June shall include a statement to that effect. If actions taken by Ash Grove during SSM events occurring between July 1 and December 31 of each year were consistent with the procedures in Ash Grove's SSM plan, the SSM report for the month of December shall include a statement to that effect. Each SSM report shall identify any instance where an action taken by Ash Grove during an SSM event (including actions taken to correct a malfunction) is not consistent with the SSM plan but the kiln and/or coal mill did not exceed an emission limit in Conditions EU 1.26 through 1.29. The report shall also include the number, duration and brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused an emission limit in Conditions EU 1.26 through 1.29 to be exceeded. For purposes of this report, a "malfunction" means any sudden, infrequent, and not reasonably preventable failure of kiln air pollution control equipment or the kiln process to operate in a normal or usual manner which causes, or has the potential to cause, any of the emission limitations in Conditions 1.26 through 1.29 to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[40 CFR 63.10(d)(5)(i) (5/30/03); 40 CFR 63.2 (5/30/03); 40 CFR 63.1354(b)(4) (6/14/99); WAC 173-401-615(3) (10/17/02)]

8. Subpart LLL Performance Test Reporting

Ash Grove shall report the results of each dioxin/furan performance test required by this permit. The report shall be postmarked or delivered to Puget Sound Clean Air Agency within 60 days following the completion of the performance test. With each report Ash Grove shall file a notification of compliance status as described in 40 CFR 63.9(h) (4/5/99).

[40 CFR 63.10(d)(2) (5/30/03); 40 CFR 63.9(h) (5/30/03); 40 CFR 63.1354(b)(1) (6/14/99); WAC 173-401-615(3) (10/17/02)]

9. Annual Emissions Reporting

Ash Grove shall report annually to the Puget Sound Clean Air Agency for those air contaminants during the previous calendar year that equal or exceed the following (tons per year):

Carbon monoxide (CO) emissions	25
Facility combined total of all toxic air contaminants (TAC) emissions	6
Any single toxic air contaminant (TAC) emissions	2
Nitrogen oxide (NOx) emissions	25
Particulate matter (PM10) emissions	25
Particulate matter (PM2.5) emissions	25
Sulfur oxide (SOx) emissions	25
Volatile organic compounds (VOC) emissions	25

Annual emissions rates shall be reported to the nearest whole ton per year for only those contaminants that equal or exceed the thresholds above.

[Puget Sound Clean Air Agency Regulation I, Section 7.09(a), 10/6/97] [Puget Sound Clean Air Agency Regulation I, Section 7.09(a), 9/10/98 (*State Only*)]

10. Complaint Response Reporting

Ash Grove shall submit in writing to Puget Sound Clean Air Agency a report documenting all complaints received with a summary of the nature of the complaint, the conclusion of the investigation, and any corrective action taken in response. This report shall be submitted as an attachment to the CEM report required by Condition II.C.4. In the event there are no reportable events, the Complaint Response Report shall consist of a statement to that effect.

[WAC 173-401-615(3) (10/17/02)]

D. Recordkeeping

1. General Recordkeeping

Ash Grove shall maintain records of required monitoring information that include the following if applicable:

a) The date, place as defined in the permit, and time of sampling or measurements;

b) The date(s) analyses were performed;

c) The company or entity that performed the analyses;

d) The analytical techniques or methods used;

e) The results of such analyses; and

f) The operating conditions existing at the time of sampling or measurement.

[WAC 173-401-615(2)(a), 10/17/02]

2. Changes made at the source

Ash Grove shall maintain records describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

[WAC 173-401-615(2)(b), (10/17/02)]

3. Record Retention

Records of all monitoring data and support information required by this permit shall be retained by Ash Grove for a period of five years from the date of the monitoring, sample, measurement, record, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

[WAC 173-401-615(2)(c), (10/17/02); Puget Sound Clean Air Agency Regulation I, Section 12.03(e) (4/9/98)]

4. NESHAP Subpart LLL Record Retention

Ash Grove shall maintain files of all information (including all reports and notifications) required by 40 CFR Part 63, Subpart LLL in a form suitable and readily available for inspection for at least five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks or on microfiche.

Ash Grove shall keep the SSM Plan on record to be made available for inspection, upon request, by the Puget Sound Clean Air Agency or EPA, for the life of the kiln and raw mill, or until the kiln/raw mill are no longer subject to the provisions of 40 CFR Part 63. If the SSM Plan is revised, Ash Grove shall keep previous (i.e. superseded) versions of the Plan on record, to be made available for inspection, upon request, by the Puget Sound Clean Air Agency or EPA, for five years following each revision of the Plan.

The provisions of this condition supplement, and do not supersede, the general record retention requirements set forth in Condition II.D.3 above.

[40 CFR 63.10(b)(1) (5/30/03); 40 CFR 63.6(e)(3)(v) (5/30/03); 40 CFR 63.1355(a) (6/14/99)]

5. O&M Plan Recordkeeping

Ash Grove shall document all inspections, tests and other actions required by the O&M Plan, including who conducted the inspection, tests or other actions; and the date and the results of the inspection, tests or other actions including corrective actions. Inspection records may be maintained in electronic format. Ash Grove shall maintain records of all inspections, tests, and other actions required by the O&M Plan on site and available for Puget Sound Clean Air Agency review.

[Puget Sound Clean Air Agency Regulation I, Section 7.09(b)(6), 9/10/98] [WAC 173-401-615(2)(a) (10/17/02), WAC 173-434-090, 10/18/90]

6. Complaint Response Recordkeeping

Records for complaints received concerning odor, fugitive emissions or nuisance conditions must contain the following information:

a) Date and time of the complaint,

b) Name and address of the person complaining, if known,

c) Nature of the complaint,

d) Investigation efforts and the basis for conclusions reached regarding the complaint, and

e) Date, time and nature of any corrective action taken.

[Puget Sound Clean Air Agency Regulation I, Section 7.09(b)(6), 9/10/98] [WAC 173-401-615(2)(a) (10/17/02)]

7. NSPS Recordkeeping

Ash Grove shall maintain the following information for at least two years following the date of measurements, maintenance, reports and records:

a) a file of all measurements recorded by the kiln COMS and by the continuous temperature monitors installed at the inlet to each coal mill baghouse;

b) all reports of performance tests conducted under 40 CFR Part 60 and all applicable subparts;

c) all reports of performance evaluations on the kiln COMS and the coal mill temperature monitors;

d) all reports of CMS calibration checks on the kiln COMS and the coal mill temperature monitors;

e) all records of adjustments and maintenance performed on the kiln COMS and the coal mill temperature monitors;

f) all records required by Condition II.B.9 of the permit (kiln production rate and feed rate records);

g) records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the kiln and coal mills, and of the additional NSPS affected units listed in Sections I.B.2 and I.B.3 of this permit;

h) records of any malfunction any malfunction of the air pollution control equipment serving the kiln and coal mills, and of the additional NSPS affected units listed in Sections I.B.2 and I.B.3 of this permit;

i) records of any period during which the kiln COMS or a coal mill temperature monitor is inoperative;

[40 CFR §60.7(b) and (f) (2/12/99); 40 CFR 60.63(a) (12/14/88); 40 CFR 60.253(a) (10/17/00); WAC 173-401-615(2)(a) (10/17/02)]

8. NESHAP Subpart LLL Recordkeeping

Ash Grove shall maintain relevant records for the kiln and raw mill of:

a) The occurrence and duration of each startup, shutdown or malfunction of operation of the kiln and the raw mill;

b) The occurrence and duration of each malfunction of the air pollution control equipment;

c) All maintenance performed on the air pollution control equipment;

d) Actions taken during SSM periods (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) when such actions are different from the procedures specified in the kiln SSM Plan;

e) All information necessary to demonstrate conformance with the kiln/raw mill SSM Plan when all actions taken during SSM periods (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) are consistent with the procedures specified in the SSM Plan. (The information needed to demonstrate conformance may be recorded using a checklist or other form designed to minimize the recordkeeping burden for conforming events);

f) Each period during which the kiln temperature CMS or either of the coal mill temperature CMS is malfunctioning or inoperative (including out of control periods);

g) All required measurements needed to demonstrate compliance with the dioxin/furan standards in 40 CFR 63.1343(d), as provided in 40 CFR 63.10(b)(2)(vii);

h) All results of Subpart LLL performance tests and CMS performance evaluations;

i) All measurements as may be necessary to determine the conditions of Subpart LLL performance tests and performance evaluations;

j) All CMS calibration checks;

k) All adjustments and maintenance performed on the kiln temperature CMS and on each coal mill temperature CMS;

l) Any information demonstrating whether Ash Grove is meeting the requirements for a waiver of recordkeeping or reporting requirements under 40 CFR Part 63, if Ash Grove has been granted a waiver under 40 CFR 63.10(f);

m) All emission levels relative to the criterion for obtaining permission to use an alternative to the relative accuracy test if Ash Grove has been granted such permission under 40 CFR 63.8(f)(6);

n) All documentation supporting initial notifications and notifications of compliance status under 40 CFR 63.9;

o) All required temperature CMS measurements (including monitoring data recorded during unavoidable CMS breakdowns and out of control periods);

p) The date and time identifying each period during which the kiln temperature CMS and each coal mill temperature CMS was inoperative except for zero (low level) and high level checks;

q) The date and time identifying each period during which the kiln temperature CMS and each coal mill temperature CMS was out of control, as defined in 40 CFR 63.8(c)(7);

r) The date and time of commencement and completion of each period of excess emissions and parameter monitoring exceedances of the dioxin/furan emission limits in Conditions EU 1.26 through 1.29 that occur during startups, shutdowns and malfunctions of the kiln/raw mill;

s) The date and time of commencement and completion of each period of excess emissions and parameter monitoring exceedances of the dioxin/furan emission limits in Conditions EU 1.26 through 1.29 that occur during periods other than SSM periods;

t) For each malfunction of the kiln, raw mill, or kiln air pollution control equipment, the nature and cause of the malfunction (if known) and the corrective action taken or preventive measures adopted

u) For each occasion on which the temperature CMS on the kiln or either coal mill temperature CMS was inoperative or out of control, the nature of the repairs or adjustments to the CMS;

v) The total kiln, raw mill and coal mill operating time during the reporting period.

[40 CFR 63.1355(b) (6/14/99); 40 CFR 63.10(b) and (c) (5/30/03)]

9. Subpart LLL Applicability Determination Recordkeeping

Ash Grove shall maintain on site records of its determination that the Seattle plant is not a Subpart LLL major source for at least five years after the determination, or until the facility changes its operations to become a major source, whichever comes first. The record of the applicability determination must be signed by the person making the determination and include the analysis that demonstrates the basis for the determination. The analysis shall be sufficiently detailed to allow EPA or the Puget Sound Clean Air Agency to make a finding about the source's applicability status with regard to the relevant standard or other requirement.

[40 CFR 63.10(b)(3) (5/30/03)]

10. SO2, CO, and NOx Mass Emission Rate Recordkeeping

Ash Grove shall maintain on site records which document the 12-month rolling total calculations for NOx emissions from the kiln, the calendar year calculations for SO2 and CO emissions from the kiln and summary 8-hour block average CO mass emission rates from the cement kiln. The records shall include the monthly calculations for each annual pollutant value, sufficient documentation to demonstrate the conversions from CEM data to mass emission rates, sufficient documentation to demonstrate the calculation methods used for mass emission rate data that is not CEM based, and documentation showing that all kiln operational time is included in the totals. The CEM data conversions used to generate mass emission rate values for these calculations shall be documented and retained with the record. Emission rate estimates used for operational periods lacking CEM data also shall be documented and retained.

[WAC 173-401-615(3), 10/17/02]

III. PROHIBITED ACTIVITIES

Ash Grove is prohibited from conducting, causing, or allowing the following activities:

A. Adjustment for Atmospheric Conditions

Varying the rate of emissions of a pollutant according to atmospheric conditions or ambient concentrations of that pollutant is prohibited, except as directed according to air pollution episode regulations. [WAC 173-400-205, 8/20/93]

B. Open Burning

Ash Grove shall not conduct open burning during any stage of an air pollution episode or period of impaired air quality and shall not conduct any open burning other than the following types:

1. Fires consisting solely of charcoal, propane, natural gas, or wood used solely for the preparation of food that comply with WAC 173-425-020(1) and WAC 173-425-030(21) and
2. Fires for instruction in the methods of fighting fires, provided that the person conducting the training fire complies with Puget Sound Clean Air Agency Regulation I, Section 8.07.

[Puget Sound Clean Air Agency Regulation I, Sections 8.04(a), 11/09/2000 and 8.07, 9/09/1999] [WAC 173-425-020(1), 3/13/2000; WAC 173-425-030(21), 3/13/2000; RCW 70.94.743, 1998 c68 p1 and RCW 70.94.775(2), 1995 c362 p2 State/Puget Sound Clean Air Agency only]

C. Refuse Burning

Ash Grove shall not cause or allow the burning of combustible refuse except in a multiple chamber incinerator provided with control equipment. Ash Grove shall not operate refuse burning equipment any time other than daylight hours. [Puget Sound Clean Air Agency Regulation I, Section 9.05, 12/9/93]

D. Concealment

Ash Grove shall not cause or allow the installation or use of any device or use of any means which, without resulting in a reduction in the total amount of air contaminant emitted, conceals an emission of an air contaminant which would otherwise violate Puget Sound Clean Air Agency Regulation I, Article 9 or Chapter 173-400 WAC. [Puget Sound Clean Air Agency Regulation I, Section 9.13(a), 6/9/88; WAC 173-400-040(7), 8/20/93]

E. Masking

Ash Grove shall not cause or allow the installation or use of any device or use of any means designed to mask the emission of an air contaminant that causes detriment to health, safety or welfare of any person or conceals or masks an emission of an air contaminant that would otherwise violate Regulation I, Article 9 or Chapter 173-400 WAC. [Puget Sound Clean Air Agency Regulation I, Section 9.13(b), 6/9/88; and WAC 173-400-040(7), 8/20/93]

F. Ambient Standards

Ash Grove shall not cause or allow the emission of air contaminants in sufficient quantity as to exceed any ambient air quality standard in Puget Sound Clean Air Agency Regulation I Section 11.01. [Puget Sound Clean Air Agency Regulation I, Section 11.01(b), 4/14/94]

G. Tampering

Ash Grove shall not render inaccurate any monitoring device or method required under Chapter 70.94 RCW, or any ordinance, resolution, regulation, permit, or order in force pursuant thereto.

[WAC 173-400-105(8), 8/21/98 *STATE ONLY*]

H. False Statements

Ash Grove shall not make any false material statement, representation or certification in any form, notice, or report required under Chapter 70.94 RCW, or any ordinance, resolution, regulation, permit, or order in force pursuant thereto.

[WAC 173-400-105(7), 8/21/98 *STATE ONLY*]

IV. ACTIVITIES REQUIRING ADDITIONAL APPROVAL

Ash Grove shall file notification and obtain the necessary approval from Puget Sound Clean Air Agency before conducting any of the following:

A. New Source Review

Ash Grove shall not construct, install, establish, or modify an air contaminant source, except those sources that are excluded by Puget Sound Clean Air Agency Regulation I, Section 6.03(b), unless a "Notice of Construction and Application for Approval" has been filed with and approved by Puget Sound Clean Air Agency. [Puget Sound Clean Air Agency Regulation I, Section 6.03, 7/12/01] [WAC 173-460-040 State/Puget Sound Clean Air Agency only]

B. Replacement or Substantial Alteration of Emission Control Technology

Ash Grove shall file a Notice of Construction and Application for Approval according to WAC 173-400-114 with Puget Sound Clean Air Agency before replacing or substantially altering any emission control technology installed at the facility. [Puget Sound Clean Air Agency Regulation I, Section 6.01 (11/17/05) (State/Puget Sound Clean Air Agency Only)] [WAC 173-400-114, RCW 70.94.153 (1991) State/Puget Sound Clean Air Agency only]

C. Asbestos

Ash Grove shall comply with 40 CFR 61.145 and 61.150 when conducting renovation or demolition activities at the facility. [40 CFR 61.145, 4/7/1993 and 61.150, 1/16/1991]

Ash Grove shall comply with Puget Sound Clean Air Agency Regulation III, Article 4 when conducting any asbestos project, renovation, or demolition activities at the facility. [Puget Sound Clean Air Agency Regulation III, Article 4, 7/13/00 (*State Only*)]

D. Spray Coating

Ash Grove shall comply with Puget Sound Clean Air Agency Regulation I, Section 9.16(a) when conducting or allowing any operation that involves the use of spray equipment to apply any VOC-containing material.

[Puget Sound Clean Air Agency Reg. I: 9.16 (7/12/01), State/Puget Sound Clean Air Agency only; however, will become federally enforceable when EPA incorporates it into the SIP]

V. STANDARD TERMS AND CONDITIONS

A. Duty to comply

Ash Grove shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of Chapter 70.94 RCW and, for federally enforceable provisions, a violation of the Federal Clean Air Act (FCAA). Such violations are grounds for enforcement action; for permit termination, revocation and re-issuance, or modification; or for denial of a permit renewal application.

[Puget Sound Clean Air Agency Regulation I, Section 7.05, 10/28/93, WAC 173-401-620(2)(a), 11/4/93]

B. Permit actions

This permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by Ash Grove for a permit modification, revocation and re-issuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

[WAC 173-401-620(2)(c), 11/4/93]

C. Property rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

[WAC 173-401-620(2)(d), 11/4/93]

D. Duty to provide information

Ash Grove shall furnish to the Puget Sound Clean Air Agency, within a reasonable time, any information that the Puget Sound Clean Air Agency may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, Ash Grove shall also furnish to the Puget Sound Clean Air Agency copies of records required to be kept by the permit or, for information claimed to be confidential, Ash Grove may furnish such records directly to EPA Region 10 along with a claim of confidentiality. The Puget Sound Clean Air Agency shall maintain the confidentiality of such information in accordance with RCW 70.94.205.

[WAC 173-401-620(2)(e), 11/4/93]

E. Permit fees

Ash Grove shall pay fees as a condition of this permit in accordance with the Puget Sound Clean Air Agency Regulation I, Article 7. Failure to pay fees in a timely fashion shall subject Ash Grove to civil and criminal penalties as prescribed in Chapter 70.94 RCW.

[WAC 173-401-620(2)(f), 11/4/93]

F. Emissions trading

No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in this permit.

[WAC 173-401-620(2)(g), 11/4/93]

G. Severability

If any provision of this permit is held to be invalid, all unaffected provisions of the permit shall remain in effect and be enforceable.

[WAC 173-401-620(2)(h), 11/4/93]

H. Permit appeals

This permit or any condition in it may be appealed only by filing an appeal with the Pollution Control Hearings Board and serving it on the Puget Sound Clean Air Agency within thirty days of receipt, pursuant to RCW 43.21B.310 and WAC 173-401-735. The provision for appeal in this section is separate from and additional to any federal rights to petition and review found under §505(b) of the FCAA.

[WAC 173-401-620(2)(i) and WAC 173-401-735, 11/4/93]

I. Permit continuation

This permit and all terms and conditions contained therein, including any permit shield provided under WAC 173-401-640, shall not expire until the renewal permit has been issued or denied if a timely and complete application has been submitted. An application shield granted under WAC 173-401-705(2) shall remain in effect until the renewal permit has been issued or denied if a timely and complete permit application has been submitted.

[WAC 173-401-620(2)(j), 11/4/93]

J. Federal enforceability

All terms and conditions of this permit are enforceable by the EPA administrator and by citizens under the FCAA, except for those terms and conditions designated in the permit as not federally enforceable.

[WAC 173-401-625, 11/4/93]

K. Inspection and entry

Upon presentation of credentials and other documents as may be required by law, Ash Grove shall allow the Puget Sound Clean Air Agency or an authorized representative to:

1. Enter Ash Grove's premises or where records must be kept under the conditions of this permit;
2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices or operations regulated or required under the permit; and
4. As authorized by WAC 173-400-105 and the FCAA, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

[WAC 173-401-630(2) (11/4/93); RCW 70.94.200 (1991) State/Puget Sound Clean Air Agency only]

L. Compliance requirements

Ash Grove shall continue to comply with all applicable requirements with which the source is currently in compliance. Ash Grove shall meet on a timely basis any applicable requirements that become effective during the permit term.

[WAC 173-401-630(3), WAC 173-401-510(2)(h)(iii) 11/4/93]

M. Compliance certifications

Ash Grove shall submit a certification of compliance with permit terms and conditions once per year. The first such certification shall cover a one-year period commencing upon the date of issuance of this permit. Each certification shall include:

1. The identification of each term or condition of the permit that is the basis of the certification;
2. The compliance status;
3. Whether compliance was continuous or intermittent; and
4. The method(s) used for determining the compliance status of the source, currently and over the reporting period. These methods must be consistent with the permit Monitoring, Maintenance and Recordkeeping Methods.

All compliance certifications shall be submitted to EPA Region 10 and to Puget Sound Clean Air Agency, at the following addresses, within 30 days after the close of the period covered by the certification:

Puget Sound Clean Air Agency Attn.: Operating Permit Certification 1904 3rd Ave, Suite 105 Seattle, Washington 98101	EPA Region 10, Mail Stop OAQ-107 Attn.: Air Operating Permits 1200 Sixth Avenue Seattle, Washington 98101

[WAC 173-401-630(5) 11/4/93]

N. Performance Testing

For the purpose of determining compliance with an emission standard, Puget Sound Clean Air Agency or the Washington State Department of Ecology may conduct testing of an emission unit or require Ash Grove to have it tested. In the event Puget Sound Clean Air Agency or Ecology conducts the test, Ash Grove shall be given an opportunity to observe the sampling and to obtain a sample at the same time.

[Puget Sound Clean Air Agency Regulation I, Section 3.05(b), 2/10/94; WAC 173-400-105(4), 8/20/93]

Ash Grove shall notify Puget Sound Clean Air Agency in writing at least 2 weeks (14 days) prior to any compliance test and provide Puget Sound Clean Air Agency an opportunity to review the test plan and to observe the test. Provided, Ash Grove shall provide the Puget Sound Clean Air Agency at least 30 days prior notice of any NSPS (40 CFR Part 60) performance test, and 60 days prior notice of any NESHAP (40 CFR Part 63) performance test. If there is a delay in conducting a scheduled NSPS or NESHAP performance test, Ash Grove shall notify the Puget Sound Clean Air Agency as soon as possible of any delay, in accordance with procedures specified in 40 CFR 60.8(d) (for NSPS testing) and 40 CFR 63.7(b)(2) (for NESHAP testing).

[Puget Sound Clean Air Agency Regulation I, Section 3.07(b) (2/9/95); 40 CFR 60.8(d) (2/12/99); 40 CFR 63.7(b) (10/7/00)]

If required by Puget Sound Clean Air Agency to perform a compliance test, Ash Grove shall submit a report to Puget Sound Clean Air Agency no later than 60 days after the test. The report shall include:

(a) A description of the source and the sampling location;

(b) The time and date of the test;

(c) A summary of results, reported in units and for averaging periods consistent with the applicable emission standard;

(d) A description of the test methods and quality assurance procedures employed;

(e) The amount of fuel burned and raw material processed by the source during the test;

(f) The operating parameters of the source and control equipment during the test;

(g) Field data and example calculations; and

(h) A statement signed by the senior management official of the testing firm certifying the validity of the source test report.

[Puget Sound Clean Air Agency Regulation I, Section 3.07(c) (2/9/95)]

O. Credible Evidence

For the purpose of establishing whether or not a person has violated or is in violation of any provision of chapter 70.94 RCW, any rule enacted pursuant to that chapter, or any permit or order issued thereunder, nothing in Puget Sound Clean Air Agency Regulation I shall preclude the use, including the exclusive use of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed.

[Puget Sound Clean Air Agency Regulation I, Section 3.06 (10/08/98); State/Puget Sound Clean Air Agency only]

For purposes of Federal enforcement, nothing in 40 CFR Part 52 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether Ash Grove would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed.

[40 CFR 52.12(c) and 52.33(a) (2/24/97)]

P. NSPS and NESHAP Performance Testing

NSPS performance tests shall be conducted and data reduced in accordance with procedures contained in 40 CFR 60.8 and in each applicable subpart of 40 CFR Part 60. Performance tests required under 40 CFR Part 63, Subpart LLL shall be conducted and data reduced in accordance with relevant procedures contained in 40 CFR 63.7 and 63.1349.

[40 CFR §60.8 (2/12/99); 40 CFR 63.7 (4/5/02); 40 CFR 63.1349 (12/6/02)]

Q. Certification of Truth, Accuracy and Completeness

Any application form, report, or compliance certification submitted pursuant to this permit shall contain certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

[WAC 173-401-520, 11/4/93]

R. Emergencies

An emergency, as defined in WAC 173-401-645(l), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the conditions of WAC 173-401-645(3) are met.

The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

1. An emergency occurred and that Ash Grove can identify the cause(s) of the emergency;
2. The permitted facility was at the time being properly operated;
3. During the period of the emergency Ash Grove took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in the permit; and
4. Ash Grove submitted notice of the emergency to the Puget Sound Clean Air Agency within two (2) working days of the time when the emissions limitations were exceeded due to the emergency or shorter periods of time specified in an applicable requirement. This notice fulfills the requirement of WAC 173-401-615(3)(b) unless the excess emissions represent a potential threat to human health or safety. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

In any enforcement proceeding, Ash Grove has the burden of proof to establish the occurrence of an emergency. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

[WAC 173-401-645, 11/4/93]

S. Unavoidable excess emissions

Excess emissions due to startup or shutdown conditions, scheduled maintenance or upsets that are determined to be unavoidable under the procedures and criteria in WAC 173-400-107 shall be excused and not subject to penalty. For any excess emission that Ash Grove wants the Puget Sound Clean Air Agency to consider unavoidable and excusable under WAC 173-400-107, Ash Grove shall submit the information required under WAC 173-400-107.

[WAC 173-400-107(2) (8/20/93)]

T. Need to halt or reduce activity not a defense

It shall not be a defense for Ash Grove in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

[WAC 173-401-620(2)(b), 11/4/93]

U. Stratospheric ozone and climate protection

1. Ash Grove shall comply with the following standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:
   i) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156;
   ii) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158;
   iii) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.
2. Ash Grove may switch from any ozone-depleting substance to any alternative approved pursuant to the Significant New Alternatives Program (SNAP), 40 CFR Part 82, Subpart G, without a permit revision but shall not switch to a substitute listed as unacceptable pursuant to such program. [40 CFR 82.174]
3. Any certified technician employed by Ash Grove shall keep a copy of their certification at their place of employment. [40 CFR 82.166(1)]
4. Ash Grove shall not willfully release any regulated refrigerant and shall use refrigerant extraction equipment to recover regulated refrigerant when servicing, repairing or disposing of commercial air conditioning, heating, or refrigeration systems.
   [RCW 70.94.970(2) and (4), 11/12/97 State/Puget Sound Clean Air Agency only]

V. RACT satisfied

Emission standards and other requirements contained in rules or regulatory orders in effect at the time of this permit issuance shall be considered RACT for the purposes of issuing this permit.

[WAC 173-401-605(3), 11/4/93]

W. Risk management programs

In accordance with 40 CFR Part 68, if Ash Grove has or receives more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, Ash Grove shall comply with the requirements of the Chemical Accident Prevention Provisions of 40 CFR Part 68 no later than the following dates:

1. Three years after the date on which a regulated substance is first listed under 40 CFR 68.130, or
2. The date on which a regulated substance is first present above a threshold quantity in a process.

[40 CFR 68.10, 1/6/99]

X. Definitions

Unless otherwise defined in this permit, the terms used in this permit shall have the same meaning ascribed to them in WAC 173-401-200.

[WAC 173-401-200, 10/17/02]

Y. Duty to supplement or correct application

Upon becoming aware that it has failed to submit any relevant facts in a permit application or that it has submitted incorrect information in a permit application, Ash Grove shall promptly submit such supplementary facts or corrected information to the Puget Sound Clean Air Agency.

[WAC 173-401-500(6), 10/17/02]

VI. PERMIT ACTIONS

A. Permit Renewal, Revocation and Expiration

1) **Renewal application**. Ash Grove shall submit a complete permit renewal application to the Puget Sound Clean Air Agency no later than 12 months prior to the expiration of this permit. Puget Sound Clean Air Agency will send Ash Grove a renewal application no later than 18 months prior to the expiration of this permit. Failure of the Puget Sound Clean Air Agency to send Ash Grove a renewal application shall not relieve Ash Grove from the obligation to file a timely and complete renewal application.

   [WAC 173-401-710(1), WAC 173-401-500(2), 10/17/02]

2) **Expired permits**. Permit expiration terminates Ash Grove's right to operate unless a timely and complete renewal application has been submitted consistent with WAC 173-401-710(1) and WAC 173-401-500. All terms and conditions of the permit shall remain in effect after this permit expires if a timely and complete permit application has been submitted.

   [WAC 173-401-710(3), 10/17/02]

3) **Revocation of permits**. Puget Sound Clean Air Agency may revoke a permit only upon the request of Ash Grove or for cause. Puget Sound Clean Air Agency shall provide at least thirty days written notice to Ash Grove prior to revocation of the permit or denial of a permit renewal application. Such notice shall include an explanation of the basis for the proposed action and afford Ash Grove an opportunity to meet with the Puget Sound Clean Air Agency prior to the Puget Sound Clean Air Agency's final decision. A revocation issued under this condition may be issued conditionally with a future effective date and may specify that the revocation will not take effect if Ash Grove satisfies the specified conditions before the effective date. Nothing in this subsection shall limit the Puget Sound Clean Air Agency's authority to issue emergency orders.

   [WAC 173-401-710(4), 10/17/02]

B. Administrative Permit Amendments

1) **Definition.** An "administrative permit amendment" is a permit revision that:

   a) Corrects typographical errors;

   b) Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at Ash Grove;

   c) Requires more frequent monitoring or reporting by Ash Grove;

   d) Allows for a change in ownership or operational control of a source where the Puget Sound Clean Air Agency determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Puget Sound Clean Air Agency;

e) Incorporates into the permit the terms, conditions, and provisions from orders approving notice of construction applications processed under an EPA-approved program, provided that such a program meets procedural requirements substantially equivalent to the requirements of WAC 173-401-700, 173-401-725, and 173-401-800 that would be applicable to the change if it were subject to review as a permit modification, and compliance requirements substantially equivalent to those contained in WAC 173-401-600 through 173-401-650.

[WAC 173-401-720(1), 11/4/93]

2) **Administrative permit amendment procedures**. An administrative permit amendment may be made by the Puget Sound Clean Air Agency consistent with the following:

a) Puget Sound Clean Air Agency shall take no more than sixty days from receipt of a request for an administrative permit amendment to take final action on such request, and may incorporate such changes without providing notice to the public or affected states provided that it designates any such permit revisions as having been made pursuant to this paragraph.

b) Puget Sound Clean Air Agency shall submit a copy of the revised permit to EPA.

c) Ash Grove may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request.

[WAC 173-401-720(3), 11/4/93]

3) **Permit shield**. Puget Sound Clean Air Agency shall, upon taking final action granting a request for an administrative permit amendment, allow coverage by the permit shield in WAC 173-401-640 for administrative permit amendments made pursuant to Part (1)(e) of this condition.

[WAC 173-401-720(4), 11/4/93]

C. Changes not Requiring Permit Revisions

1) **General**.

a) Ash Grove is authorized to make the changes described in this section without a permit revision, providing the following conditions are met:

i) The proposed changes are not Title I modifications as defined in WAC 173-401-200;

ii) The proposed changes do not result in emissions which exceed those allowable under the permit, whether expressed as a rate of emissions, or in total emissions;

iii) The proposed changes do not alter permit terms that are necessary to enforce limitations on emissions from units covered by the permit; and

iv) Ash Grove provides EPA and the Puget Sound Clean Air Agency with written notification at least seven days prior to making the proposed changes except that written notification of a change made in response to an emergency shall be provided as soon as possible after the event.

b) Permit attachments. Ash Grove and the Puget Sound Clean Air Agency shall attach each notice to their copy of the relevant permit.

2) **Section 502 (b)(10) changes**. Pursuant to the conditions in Subsection (1) of this section, Ash Grove is authorized to make Section 502(b)(10) changes (as defined in WAC 173-401-200) without a permit revision.

a) For each such change, the written notification required under Subsection (1)(a)(iv) of this condition shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

b) The permit shield authorized under WAC 173-401-640 shall not apply to any change made pursuant to this paragraph.

3) **SIP authorized emissions trading.** Pursuant to the conditions in Subsection (1) of this condition, Ash Grove is authorized to trade increases and decreases in emissions in the permitted facility, where the Washington state implementation plan provides for such emissions trades without requiring a permit revision. This provision is available in those cases where the permit does not already provide for such emissions trading.

a) Under this Subsection (3), the written notification required under Subsection (1)(a)(iv) of this condition shall include such information as may be required by the provision in the Washington state implementation plan authorizing the emissions trade, including at a minimum, when the proposed change will occur, a description of each such change, any change in emissions, the permit requirements with which Ash Grove will comply using the emissions trading provisions of the Washington state implementation plan, and the pollutants emitted subject to the emissions trade. The notice shall also refer to the provisions with which Ash Grove will comply in the applicable implementation plan and that provide for the emissions trade.

b) The permit shield described in WAC 173-401-640 shall not extend to any change made under this paragraph. Compliance with the permit requirements that Ash Grove will meet using the emissions trade shall be determined according to requirements of the applicable implementation plan authorizing the emissions trade.

[WAC 173-401-722, 10/17/02]

D. Off Permit Changes

1) Ash Grove shall be allowed to make changes not specifically addressed or prohibited by the permit terms and conditions without requiring a permit revision, provided that the proposed changes do not weaken the enforceability of existing permit conditions. Any change that is a Title I modification or is a change subject to the acid rain requirements under Title IV of the FCAA must be submitted as a permit revision.

2) Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition.

3) Ash Grove must provide contemporaneous written notice to the Puget Sound Clean Air Agency and EPA of each such change, except for changes that qualify as insignificant under WAC 173-401-530. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

4) The change shall not qualify for the permit shield under WAC 173-401-640.

5) Ash Grove shall keep a record describing changes made at Ash Grove that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

6) When making a change under this section, Ash Grove shall comply with applicable preconstruction review requirements established pursuant to RCW 70.94.152 and Puget Sound Clean Air Agency Regulation I, Article 6.

[WAC 173-401-724, 11/4/93]

E. Permit Modification

1) **Definition**. A permit modification is any revision to this permit that cannot be accomplished under provisions for administrative permit amendments under WAC 173-401-720.

2) **Procedures**. Minor permit modification procedures.

a) Criteria.

i) Minor permit modification procedures shall be used for those permit modifications that:

a) Do not violate any applicable requirement;

b) Do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

c) Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

d) Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that Ash Grove has assumed to avoid an applicable requirement to which Ash Grove would otherwise be subject. Such terms and conditions include:

(1) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I of the FCAA; and

(2) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the FCAA;

e) Are not modifications under any provision of Title I of the FCAA;

ii) Notwithstanding (a)(i) of this subsection, and Subsection (3) of this section, the Puget Sound Clean Air Agency may allow the use of minor permit modification procedures for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that the use of such minor permit modification procedures is explicitly provided for in the Washington state implementation plan or in applicable requirements promulgated by EPA and in effect on April 7, 1993.

b) Application. An application requesting the use of minor permit modification procedures shall meet the requirements of WAC 173-401-510 and shall include the following:

i) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

ii) Ash Grove's suggested draft permit;

iii) Certification by a responsible official, consistent with WAC 173-401-520, of the truth, accuracy, and completeness of the application and that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

iv) Completed forms for the Puget Sound Clean Air Agency to use to notify EPA and affected states as required under WAC 173-401-810 and 173-401-820.

c) Ash Grove's ability to make change. Ash Grove may make the change proposed in its minor permit modification application immediately after it files such application provided that those changes requiring the submissions of a notice of construction application have been reviewed and approved by the Puget Sound Clean Air Agency. After Ash Grove makes the change allowed by the preceding sentence, and until the Puget Sound Clean Air Agency takes any of the actions specified in WAC 173-401-725(d), Ash Grove must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, Ash Grove need not comply with the existing permit terms and conditions it seeks to modify. However, if Ash Grove fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

d) Permit shield. The permit shield under WAC 173-401-640 shall not extend to minor permit modifications.

3) **<u>Group processing of minor permit modifications.</u>** Consistent with WAC 173-401-725(3), the Puget Sound Clean Air Agency may process groups of a source's applications for certain modifications eligible for minor permit modification processing.

4) **Significant modification procedures**.

a) Criteria. Significant modification procedures shall be used for applications requesting permit modifications that do not qualify as minor permit modifications or as administrative permit amendments. Every significant change in existing monitoring permit terms or conditions and every relaxation of reporting or recordkeeping permit terms or conditions shall be considered significant. Nothing herein shall be construed to preclude Ash Grove from making changes consistent with Chapter 173-401 WAC that would render existing permit compliance terms and conditions irrelevant.

b) Significant permit modifications shall meet all requirements of Chapter 173-401 WAC, including those for applications, public participation, review by affected states, and review by EPA, as they apply to permit issuance and permit renewal. Puget Sound Clean Air Agency shall complete review on the majority of significant permit modifications within nine months after receipt of a complete application.

[WAC 173-401-725, 11/4/93]]

F. Reopening for Cause

1) **Standard provisions.** This permit shall be reopened and revised under any of the following circumstances:

a) Additional applicable requirements become applicable to Ash Grove with a remaining permit term of three or more years. Such a reopening shall be completed not later than eighteen months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended pursuant to WAC 173-401-620(2)(j);

b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by EPA, excess emissions offset plans shall be deemed to be incorporated into the permit;

c) Puget Sound Clean Air Agency or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or

d) Puget Sound Clean Air Agency or EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

2) **Procedures**. Proceedings to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Such reopening shall be made as expeditiously as practicable.

3) **Notice**. Reopenings under this section shall not be initiated before a notice of such intent is provided to Ash Grove by the Puget Sound Clean Air Agency at least thirty days in advance of the date that the permit is to be reopened, except that the Puget Sound Clean Air Agency may provide a shorter time period in the case of an emergency.

[WAC 173-401-730, 11/4/93]

VII. PERMIT SHIELD

Compliance with the conditions of the permit shall be deemed compliance with any applicable requirements contained in Sections I through VI of this permit that are specifically identified in this permit as of the date of permit issuance. [WAC 173-401-640(1)]

Nothing in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the FCAA (emergency orders), including the authority of the administrator under that section;

(2) The liability of an owner or operator of Ash Grove for any violation of applicable requirements prior to or at the time of permit issuance;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the FCAA;

(4) The ability of EPA to obtain information from a source pursuant to Section 114 of the FCAA; or

(5) The ability of Puget Sound Clean Air Agency to establish or revise requirements for the use of reasonably available control technology (RACT) as provided in Chapter 252, Laws of 1993.

[WAC 173-401-640(4), 11/4/93]

VIII. INAPPLICABLE REQUIREMENTS

As of the date of permit issuance, the requirements listed below do not apply to Ash Grove, or to the specific emission units specified below for the reasons indicated. The permit shield applies to all requirements so identified.

[WAC 173-401-640(2), 11/4/1993]

Citation	Type of Requirement	Basis for Non-applicability
RCW 70.94.531	Transportation Demand Management	This section requires, within 6 months after King County's adoption of a commute trip reduction plan, employers develop a trip reduction program and submit the program to the Puget Sound Clean Air Agency for review. This section is not an applicable requirement because it applies only to "major employers" that employ 100 or more full-time employees at a single work site who begin their work day between 6:00 a.m. and 9:00 a.m. Ash Grove does not employ 100 or more workers; therefore, it is not an applicable requirement. This requirement does not apply to emission units or stationary sources.
WAC 173-400-040(3)(b) and (8)(b)	Fugitive emission standards for emission units identified as “a significant contributor to the nonattainment status of a designated nonattainment area	There are no designated nonattainment areas in the vicinity of the Seattle plant, and no emission unit at the Seattle plant has been identified as a “significant contributor” to the nonattainment status of a designated nonattainment area.
WAC 173-400-075 (except asbestos NESHAPS)	Emissions Standards for Sources Emitting Hazardous Air Pollutants	This requirement adopts the national emissions standards for hazardous air pollutants in 40 CFR Part 61 by reference and gives Ecology authority to conduct source tests and access to records to determine compliance. WAC 173-400-075 is not an applicable requirement because none of the subparts of 40 CFR Part 61 applies to any emissions unit at Ash Grove.
WAC 173-400-151	Retrofit Requirements for Visibility Protection	This is inapplicable because Ecology has not identified Ash Grove as a source causing or contributing to impaired visibility in a Class I area. If Ecology makes such a determination, Puget Sound Clean Air Agency will reopen the permit.
WAC 173-434 Solid Waste Incinerator Facilities (as amended on 12/22/03)	Emission and operational limits for solid waste incinerator facilities	WAC 173-434 (as amended on December 22, 2003) does not apply to Ash Grove because the amendments exempt from the coverage of WAC ch. 173-434 the only solid waste materials that Ash Grove currently is authorized to combust. The previous 10/18/90 version of WAC 173-434 was superseded with the approval the current

Citation	Type of Requirement	Basis for Non-applicability
		version into the Washington State Implementation Plan, effective September 6, 2005
WAC 173-435	Emergency Episode Plans	This chapter is not an applicable requirement until it is triggered by a request from Ecology to prepare a Source Emission Reduction Plan (SERP). Absent a request for a SERP, nothing in this chapter (except WAC 173-435-050(2)) imposes substantive requirements on sources.
WAC 173-435-050(2)	Action Procedures	Subsection (2) is not an applicable requirement because Ash Grove's operations do not include open burning. The other subsections are not applicable requirements, because they do not impose substantive requirements on facilities.
WAC 173-470	Ambient Air Quality Standards for Particulate Matter	Ambient air quality standards are not "applicable requirements" [See WAC 173-401-200(4)(a)(xii) (10/17/02); 57 Fed. Reg. 32276 (July 22, 1992)].
WAC 173-474	Ambient Air Quality Standards for Sulfur Oxides	Ambient air quality standards are not "applicable requirements" [See WAC 173-401-200(4)(a)(xii) (10/17/02); 57 Fed. Reg. 32276 (July 22, 1992)].
WAC 173-475	Ambient Air Quality Standards for Carbon Monoxide, Ozone, and Nitrogen Dioxide	Ambient air quality standards are not "applicable requirements" [See WAC 173-401-200(4)(a)(xii) (10/17/02); 57 Fed. Reg. 32276 (July 22, 1992)].
WAC 173-480	Ambient Air Quality Standards and Emission Limits for Radionuclides	Ambient air quality standards are not "applicable requirements" [See WAC 173-401-200(4)(a)(xii) (10/17/02); 57 Fed. Reg. 32276 (July 22, 1992)]. These standards are also not applicable requirements because Ash Grove does not emit radionuclides.
WAC 173-481	Ambient Air Quality and Environmental Standards for Fluorides	Ambient air quality standards are not "applicable requirements" [See WAC 173-401-200(4)(a)(xii) (10/17/02); 57 Fed. Reg. 32276 (July 22, 1992)].
Puget Sound Clean Air Agency Reg. I: Article 5	Registration	This section will not be applicable because Title V permitted sources are not subject to these registration and reporting requirements per RCW 70.94.161(17).
Puget Sound Clean Air Agency Reg. I: 9.04(e) (04/9/98)	Venturi Scrubber	This section does not apply because Ash Grove does not operate a Venturi scrubber and Ash Grove will apply for a permit modification before installation.

Citation	Type of Requirement	Basis for Non-applicability
Puget Sound Clean Air Agency Reg. I: 12.02(b) (08/10/89)	Wet Control Equipment	This section is not an applicable requirement because Ash Grove does not use wet control equipment, and Ash Grove will apply for a permit modification before installation.
Puget Sound Clean Air Agency Reg. I: 12.03(c) (08/10/89)	Pressure Loss Through Scrubbers	This section is not applicable because Ash Grove does not use scrubbers.
Puget Sound Clean Air Agency Reg. I: 12.03(d) (08/10/89)	Scrubber Liquid Supply Rate	This section is not applicable because Ash Grove does not use scrubbers.
Puget Sound Clean Air Agency Reg. I: 12.04(b) (08/10/89)	Recordkeeping for Scrubber Operations	This section is not applicable because Ash Grove does not use scrubbers.
Puget Sound Clean Air Agency Reg. II: Articles 1, 2 & 3	Gasoline Marketing & VOC Standards	These sections are not applicable because Ash Grove does not have equipment that is governed by this regulation.
Puget Sound Clean Air Agency Reg. III: Articles 3	Chromium Standards	This section is inapplicable because Ash Grove does not have any of the listed equipment and must obtain approval before installing this type of equipment.
PSD Permit 90-03 (6/20/90) and Amendments 1 (11/7/95) and 2 (3/8/99)	PSD Permit	These versions of Permit 90-03 were superseded by Amendment 3 (10/8/01).
Puget Sound Clean Air Agency Approval Orders 3382, 5730 and 7381 (6/29/98)	New source approval orders	Superseded by Order of Approval 7381, condition 8 (6/6/01)
40 CFR Part 60, Subpart OOO	NSPS for Nonmetallic Mineral Processing Plants	40 CFR 60.670(b) states that a Subpart OOO “affected facility” that is subject to Subpart F or that follows in the plant process any facility subject to Subpart F is not subject to Subpart OOO. All equipment at the Seattle plant that falls within the Subpart OOO definition of “affected facility” is also a Subpart F “affected facility.”

Citation	Type of Requirement	Basis for Non-applicability
The requirements that are identified below are inapplicable for specific emission units or for rule and unit specific reasons. The requirements identified in the first column for these subsequent items are inapplicable only insofar as the scope and explanation provided in the third column qualifies the limitation of inapplicability and are not universally inapplicable to the entire site or for this permit beyond that scope and explanation.		
40 CFR Part 60, Subpart A	NSPS reporting requirements	NSPS notices and reports required by Subparts A, F, and Y need be submitted only to Puget Sound Clean Air Agency without parallel submittal copies to EPA. Letter of February 5, 2003 from Betty Weise, EPA Region 10 to Dennis McLerran. EPA retains responsibility for review and approval of major changes to NSPS monitoring and test methods, as described in the February 5th letter.
40 CFR 60 Part 60, Subpart F	NSPS for Portland Cement Plants	Clinker storage shed, finish mills, steel scale tanks and Group I and Group II silos are not Subpart F "affected facilities" because none of these facilities were constructed or modified after August 17, 1971. 40 CFR 60.60(b) (7/25/77).
40 CFR 60.63(b)	COMS requirement	Requirement to install COMS on "each bypass stack" does not apply to the coal mill stacks because coal mills are subject to 40 CFR Part 60, Subpart Y opacity limit, rather than Subpart F. See Memo of 4/6/95 from John Rasnic to EPA Regional Directors re Opacity at Portland Cement Plants (Applicability Determinations 9600073) and Memo of 5/12/95 from John Rasnic (Applicability Determinations 9600082).
40 CFR 60.13; 40 CFR 60.253(b)	NSPS performance specifications and QA/QC requirements for continuous monitoring systems	40 CFR 60.13 does not apply to the temperature monitors required to be installed on the coal mill stacks by 40 CFR 60.253(a)(1) because 60.13 requirements take effect "upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part," and no performance specs have been promulgated under 40 CFR Part 60, Appendix B for continuous temperature monitors.
40 CFR Part 60, Subpart Y	NSPS Standards for Coal Preparation Plants	Coal loading, transfer and storage equipment upstream of the Raw Coal Silo are not Subpart Y "affected facilities." See EPA Applicability Determinations Y002 (2/24/77) and NR90 (10/29/90)
40 CFR Part 63, Subparts A and LLL	MACT standards for Portland cement Plants	All Subpart A and Subpart LLL standards that apply to emission units at a "major source" do not

Citation	Type of Requirement	Basis for Non-applicability
(Major Source Provisions)		apply to the Seattle plant because the Seattle plant is not a "major source" within the meaning of 40 CFR 63.2.
40 CFR Part 63, Subparts A and LLL (Notifications & Reports)	MACT standards for Portland cement plants	All Subpart A and LLL requirements to submit notifications and reports to EPA do not apply to the Seattle plant, because EPA waived notice in its delegation action to Puget Sound Clean Air Agency. See 65 Fed. Reg. 10392 (2/28/00). All requirements in Subparts A and LLL to serve notifications and reports on "the Administrator" or EPA are amended to designate Puget Sound Clean Air Agency as the recipient.
40 CFR 63.7 and 63.1349(a) and (b)	MACT initial performance test requirements	The requirement to conduct a performance test to demonstrate <u>initial compliance</u> with the dioxin/furan emission standards in 40 CFR 63.1343(d) was satisfied on October 22-24, 2002 The test report and compliance notification were submitted on December 20, 2002.
40 CFR 63.9 (b) through (d) and 63.1353(b)(1)	MACT initial notification requirements	Subpart A and LLL initial notification requirements for the kiln/raw mill were satisfied by the letter of October 7, 1999 from Henrik Voldbaek to Tom Fitzsimmons et al..
40 CFR 63.1350(g)	Dioxin/furan monitoring requirements for kilns that employ carbon injection as an emission control technique	The Seattle plant does not employ carbon injection as an emission control technique.
40 CFR 63.1351(b)	Subpart LLL compliance date for affected sources that commence new construction or reconstruction after March 24, 1998	Ash Grove did not commence new construction or reconstruction on any Subpart LLL affected source after March 24, 1998.
40 CFR 63.1344(b)	Temperature limit for affected sources determined through performance test	The <u>procedure</u> in 40 CFR 1344(b) to set the temperature limit for affected sources through measurements taken during dioxin/furan performance testing does not apply to <u>the coal mills</u>, because Puget Sound Clean Air Agency approved an intermediate monitoring change establishing the coal mill temperature limit at 200 degrees F. See letter of October 18, 2002 from Steven Van Slyke to Robert Vantuyl.

IX. INSIGNIFICANT EMISSION UNITS

A. Insignificant Emission Units and Activities

1. Insignificant emission units and activities at Ash Grove are subject to all applicable requirements set forth in Sections I.A, III and IV. This permit shall not require testing, monitoring, reporting or recordkeeping for insignificant emission units or activities except as required by Puget Sound Clean Air Agency Regulation I, Sections 7.09(b) and 9.20. Compliance with Puget Sound Clean Air Agency Regulation I, Sections 7.09(b) and 9.20 shall be deemed to satisfy the requirements of WAC 173-401-615 and 173-401-630(1).

   [WAC 173-401-530(2)(c), 10/17/02]

2. Where this permit does not require testing, monitoring, recordkeeping and reporting for insignificant emissions units or activities, Ash Grove may certify continuous compliance if there were no observed, documented, or known instances of noncompliance during the reporting period. Where this permit requires testing, monitoring, recordkeeping and reporting for insignificant emission units or activities, Ash Grove may certify continuous compliance when the testing, monitoring, and recordkeeping required by the permit revealed no violations during the period, and there were no observed, documented, or known instances of noncompliance during the reporting period.

   [WAC 173-401-530(2)(d), 10/17/02]

3. An emission unit or activity that qualifies as insignificant solely on the basis of WAC 173-401-530(1)(a) shall not exceed the emission thresholds specified in WAC 173-401-530(4) until this permit is modified pursuant to Section VI.E of this permit and WAC 173-401-725.

   [WAC 173-401-530(6), 10/17/02]

As of the date of permit issuance, the emission units listed below are defined as insignificant for the reasons indicated.

Unit	Basis for IEU Designation
Lubricating oil storage tanks	WAC 173-401-532 (3)
Vehicle maintenance	WAC 173-401-532 (7)
Internal combustion engines for propelling or powering a vehicle	WAC 173-401-532(10)
Welding equipment	WAC 173-401-532(12)
Cleaning and sweeping of streets and paved surfaces	WAC 173-401-532(35)
Roads (sweep and water for dust control)	WAC 173-401-532(35)
Steam cleaner	WAC 173-401-532(39)
Kerosene, grease, and oil drums	WAC 173-401-532(42)

Unit	Basis for IEU Designation
Truck wash	WAC 173-401-532(45)
Window air conditioners	WAC 173-401-532(46)
Bathroom vents	WAC 173-401-532(48)
Fuel and exhaust emissions from vehicles in parking lots	WAC 173-401-532(54)
Staff vehicles	WAC 173-401-532(54)
Air compressor (electric)	WAC 173-401-532(88)
Diesel Fuel Tank (kiln drive standby) 185 gal	WAC 173-401-533(2)(a)
Underground Diesel Fuel Tank 2000 gal	WAC-173-401-533(2)(c)
Lignite Tank	WAC-173-401-533(2)(c)
Finish Grinding Aid Tank	WAC-173-401-533(2)(c)
Space Heaters <5 MMBtu/hr	WAC 173-401-533(2)(r)
Underground Gasoline tank 1000 gal	WAC 173-401-533(2)(t)
Safety-Kleen station	WAC 173-401-533(2)(z)
Calibration gases (for equipment)	WAC 173-401-533(3)(c)

X. APPENDIXES

A. Reference Methods (by reference only, not attached)

(1) EPA Method 5 [40 CFR 60, Appendix A, July 1, 2002]

(2) EPA Method 9 [40 CFR 60, Appendix A, July 1, 2002]

(3) EPA Method 10 [40 CFR 60, Appendix A, July 1, 2002]

(4) EPA Method 7E [40 CFR 60, Appendix A, July 1, 2002]

(5) EPA Method 6C [40 CFR 60, Appendix A, July 1, 2002]

(6) EPA Method 23 [40 CFR 60, Appendix A, July 1, 2002]

(7) EPA Method 20.A [40 CFR 51, Appendix M, July 1, 2001]

B. Non-EPA Test Methods (attached)

(1) Puget Sound Clean Air Agency Method 5 as approved by Puget Sound Clean Air Agency Board Resolution 540 dated August 11, 1983

(2) Ecology Method 9A

C. Reference Continuous Emission Monitoring Performance Specification (by reference only, not attached)

(1) EPA Performance Specification 1 (Opacity Monitoring), [40 CFR 60, Appendix B, July 1, 1992]

(2) EPA Performance Specification 2 (SO2 and NOx Monitoring) [40 CFR 60, Appendix B, July 1, 1992]

(3) EPA Performance Specification 3 (O2 Monitoring) [40 CFR 60, Appendix B, July 1, 1992]

(4) EPA Performance Specification 4 (CO Monitoring) [40 CFR 60, Appendix B, July 1, 1992]

D. EPA Quality Assurance Procedures (attached)

Continuous Emission Monitoring for Opacity: "Recommended Quality Assurance Procedures for Opacity Continuous Monitoring Systems" (EPA 340/1-86-010)

E. Elements of Opacity COMS Summary Report for 40 CFR 60.7(d) (Condition II.C.5)

Pollutant: Opacity; Reporting period dates; Company name and address; Process unit(s) description; Emission limits; Monitor manufacturer and model no.; Date of latest CMS Certification or Audit; Total source operating time in reporting period[1]

Include with the Emission Data Summary[1]:

1. The duration of excess emissions in reporting period that was due to: (a) Startup/Shutdown, (b) Control equipment problems, (c) Process problems, (d) Other known causes, and (e) Unknown causes;
2. The total duration of excess emission; and
3. [Total duration of excess emissions]/[Total source operating time]*(100) = %[2]

Include with the CMS Performance Summary[1]:

1. The CMS downtime in reporting period due to: (a) Monitor equipment Malfunctions, (b) Non-Monitor equipment Malfunctions, (c) Quality assurance calibration, (d) Other known causes, and (e) Unknown causes;
2. The Total CMS Downtime; and
3. Total CMS Downtime/[Total operating time]*(100) = %[2]

Describe any changes since last quarter in CMS, process or controls.
Certify that the information attained in the report is true, accurate, and complete.
Include Name and Signature (Title) of the responsible official and Date

1. For Opacity, record all times in minutes. For gases, record all times in hours.
2. For the reporting period: If the total duration of excess emissions is ≥ 1% or the total CMS downtime is ≥ 5% of the total operating time, both the summary report form and the excess emission report described in 60.7(c) shall be submitted.

SOUTHWEST CLEAN AIR AGENCY

AIR DISCHARGE PERMIT
04-2568R2

Date: December 16, 2008

Facility Name: Cardinal Pacific FG - Winlock
Physical Location: 545 Avery Road West
Winlock, WA 98596

SWCAA ID: 2175

PAUL T. MAIROSE
STATE OF WASHINGTON
21507
REGISTERED
PROFESSIONAL ENGINEER

REVIEWED BY: ______________________
Paul T. Mairose, Chief Engineer

APPROVED BY: ______________________
Robert D. Elliott, Executive Director

TABLE OF CONTENTS

1. Equipment/Activity Identification

ID No.	Generating Equipment/Activity	# of Units	Control Measure/Equipment	# of Units
1	Melting Furnace/Annealing Lehr	1	Spray Drier/Electrostatic Precipitator, 3R Process	1
2	Glass Cutting Operations	N/A	Restriction on Material Type and Use	N/A
3	Cullet Return System #1	N/A	Process Enclosure, Fabric Filtration (Donaldson – 41,500 acfm)	1
4	Cullet Return System #2	N/A	Process Enclosure, Fabric Filtration (Carothers/Son – 25,000 acfm)	1
5	Raw Materials Elevator – Top	1	Process Enclosure, Fabric Filtration (JBD – 324 acfm)	1
6	Cullet Elevator – Top	1	Process Enclosure, Fabric Filtration (JBD – 324 acfm)	1
7	EP Dust Collection System BH #1	N/A	Process Enclosure, Fabric Filtration (Nol-Tec – 1,500 acfm)	1
8	EP Dust Collection System BH #2	N/A	Process Enclosure, Fabric Filtration (Nol-Tec – 1,500 acfm)	1
9	Emergency Generator (Caterpillar – 2,885 bhp)	1	Low Sulfur Fuel(≤0.05% by wt), Operating Limit (≤200 hr/yr), Selective Catalytic Reduction	1

2. Approval Conditions

The following tables detail the specific requirements of this permit. In addition to the requirements listed below, equipment at this facility may be subject to other federal, state, and local regulations. The permit requirement number is identified in the left hand column. The text of the permit requirement is contained in the middle column. The emission unit, equipment, or activity to which the permit requirement applies is listed in the right hand column.

This Permit supersedes Air Discharge Permit 04-2568R1 in its entirety.

2.1 Emission Limits

No.	Emission Limits	Equipment/ Activity
1.	Emissions from the glass melting furnace exhaust stack shall not exceed the following: Pollutant — Emission Limit Fluorides (total) — 2.9 tpy Sulfuric acid — 6.9 tpy Annual emissions shall be calculated based on actual glass production and applicable emission factors consistent with the methodology found in Section 6.c of the Technical Support Document for this Permit.	1

No.	Emission Limits	Equipment/ Activity
2.	Visible emissions from the glass melting furnace exhaust stack shall not exceed the values listed below for more than 3 minutes in any one hour period as determined by a Certified Observer in accordance with SWCAA Method 9. <u>Operating Condition</u> — <u>Opacity Limit</u> Normal operation — 10% Hot fan transition — 20% Hot fan transition is intended to account for elevated dust loads that coincide with a change in lead fan status between the furnace's two hot fans. The transition period begins when a reduction in lead fan load is initiated and ends not more than 30 minutes after fan load adjustment ceases.	1
3.	Visible emissions from approved dust collectors shall not exceed 0% for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (Appendix A of SWCAA 400).	3-8
4.	Combined emissions from cullet return baghouse #2 shall not exceed the following: <u>Pollutant</u> — <u>Emission Limit</u> PM (filterable) — 0.005 gr/dscf PM_{10} (filterable) — 4.69 tpy Annual emissions shall be calculated from rated airflow, actual hours of operation, and maximum emission concentration consistent with the methodology in Section 6.a of the Technical Support Document for this Permit.	4
5.	Combined emissions from the EP Dust baghouses shall not exceed the following: <u>Pollutant</u> — <u>Emission Limit</u> PM (filterable) — 0.005 gr/dscf PM_{10} (filterable) — 0.56 tpy Annual emissions shall be calculated from rated airflow, actual hours of operation, and maximum emission concentration consistent with the methodology in Section 6.a of the Technical Support Document for this Permit.	7-8
6.	Emissions from the emergency generator shall not exceed the following: <u>Pollutant</u> — <u>Emission Limit</u> NO_X — 2.30 tpy CO — 0.42 tpy PM_{10} — 0.09 tpy Annual emissions shall be calculated from actual hours of operation and applicable emission factors consistent with the methodology found in Section 6.d of the Technical Support Document for this Permit.	9
7.	Visible emissions from diesel engine exhaust shall not exceed 10% opacity for more than 3 minutes in any one hour period as determined by a Certified Observer in accordance with SWCAA Method 9 (SWCAA 400, Appendix A). This limit does not apply during periods of cold start-up.	9

2.2 Operating Limits and Requirements

No.	Operating Limits and Requirements	Equipment/ Activity
8.	Reasonable precautions shall be taken at all times to prevent and minimize fugitive emissions from plant operations.	Facilitywide
9.	Operations that cause or contribute to a nuisance odor shall use recognized good practice and procedures to reduce these odors to a reasonable minimum.	Facilitywide
10.	Each pollution control device shall be operated whenever the processing equipment served by that control device is in operation. Control devices shall be operated and maintained in accordance with the manufacturer's specifications. Furthermore, control devices shall be operated in a manner that minimizes emissions.	1-9
11.	Emission units identified in this Permit shall be maintained and operated in total and continuous conformity with the conditions identified in this Permit. SWCAA reserves the right to take any and all appropriate action to maintain the conditions of this Permit, including directing the facility to cease operations until corrective action can be completed.	1-9
12.	Cutting lubricant used in glass cutting operations shall meet the specifications given in ASTM D-235 for Type 3C mineral spirits.	2
13.	All containers for VOC containing materials shall be kept securely closed with a lid in place except when in active use. Open containers for storage, transfer or disposal of VOC containing materials are prohibited. In addition, all VOC containing materials used to clean and/or flush spray equipment or lines during clean up shall be collected and stored in a closed container.	2
14.	A gauge shall be installed and maintained to monitor the differential pressure across filtration media in each approved dust collector.	3-8
15.	The Selective Catalytic Reduction (SCR) system shall be operated whenever the associated diesel engine is in operation and appropriate operating temperatures have been achieved by the system. The SCR system shall be operated and maintained in accordance with the manufacturer's specifications.	9
16.	The diesel engine shall be fired on #2 diesel or better. Maximum fuel sulfur content shall not exceed 0.05% by weight. Any fuel other than #2 diesel shall be approved by SWCAA in writing prior to use.	9
17.	Operation of the diesel engine for the purpose of maintenance and testing shall not exceed 200 hr/yr.	9

2.3 Monitoring and Recordkeeping Requirements

No.	Monitoring and Recordkeeping Requirements	Equipment/ Activity
18.	All records required by this Permit shall be kept for a minimum period of no less than five years and shall be maintained in a form readily available for inspection by SWCAA representatives.	1-9

No.	Monitoring and Recordkeeping Requirements	Equipment/ Activity
19.	With the exception of data logged by a computerized data acquisition system, each record required by this Air Discharge Permit shall include the date and the name of the person making the record entry.	1-9
20.	Excess emissions and upset conditions shall be recorded for each occurrence.	1-9
21.	Glass furnace hot fan transitions shall be recorded for each occurrence.	1
22.	Operation of the material handling systems shall be recorded as follows: (a) Pressure drop across each dust collector — Recorded weekly (b) Maintenance and repair activities — Recorded for each occurrence	3-8
23.	Operation of the emergency generator shall be recorded as follows: (a) Hours of engine operation — Recorded annually (b) Certification of fuel sulfur content — Recorded for each fuel shipment (c) Maintenance and repair activities — Recorded for each occurrence	9

2.4 Emission Monitoring and Testing Requirements

No.	Emission Monitoring and Testing Requirements	Equipment/ Activity
24.	The glass melting furnace shall be emission tested within 60 days of achieving maximum firing rate, but no later than 180 days after initial start-up, in accordance with Appendix A of this Permit.	1
25.	Cullet return baghouse #2 shall be emission tested within 60 days of commencing initial operation. Subsequent emission testing shall be conducted on a 60 month cycle, no later than the end of the calendar month in which the initial emission test was performed. Emission testing shall be performed in accordance with Appendix C of this Permit.	4
26.	If SWCAA issues a Notice of Violation for excess visible emissions from an EP Dust baghouse, the affected baghouse may subsequently be required to perform an emission test and/or periodic emission testing. If such emission testing is required, the affected baghouse shall be emission tested no later than 60 days following the source's receipt of the Notice of Violation. Under this provision, periodic emission testing of the affected baghouse is limited to a maximum frequency of once every 60 months. All emission testing shall be conducted in accordance with Appendix B of this Permit. Nothing in this requirement restricts SWCAA's authority under SWCAA 400-106 to order or conduct emission testing.	7-8

?.5 Reporting Requirements

No.	Reporting Requirements	Equipment/ Activity
27.	An annual emissions inventory report shall be submitted in accordance with SWCAA 400-105(1). In addition to the emissions information required under SWCAA 400-105(1), each annual report shall include an estimate of annual emission quantities for each TAP compound listed in the Technical Support Document for this Permit.	Facilitywide
28.	Excess emissions and all other deviations from permit requirements shall be reported to SWCAA as follows: • As soon as possible, but no later than 12 hours after discovery for emissions that represent a potential threat to human health or safety; • As soon as possible, but no later than 48 hours after discovery for emissions which the permittee wishes to claim as unavoidable pursuant to SWCAA 400-107(1); and • No later than 30 days after the end of the month of discovery for all other excess emissions.	1-9
29.	Upset conditions shall be reported to SWCAA as soon as possible after discovery. The permittee may provide notification to SWCAA via telephone. A message may be left on the answering machine for upset conditions that occur outside of normal business hours.	1-9
30.	The permittee shall notify SWCAA at least seven days in advance of the use of any new material, which results in the emission of toxic or hazardous air pollutants not previously emitted. In response to the notification, SWCAA may require that a written report be submitted with the following: (a) A description of the proposed change(s) in materials with an MSDS for each new material, (b) The date the change(s) is (are) to be made, (c) The change(s) in emissions of VOCs, HAPs and TAPs occurring as a result of the change, and (d) A summary of any applicable requirement(s) that would apply as a result of the change(s). If the proposed emission rate of a new TAP exceeds the applicable SQER and/or other emission limits established by this Permit or otherwise circumvents an applicable requirement, New Source Review may be required prior to making the proposed change.	1-9
31.	The initial start-up of approved emission units shall be reported to SWCAA in writing within 10 days of commencing operation.	1-9
32.	Quarterly air emissions from all emission units shall be reported to SWCAA in writing no later than 30 days after the end of each respective calendar quarter. Emissions shall be reported in terms consistent with applicable emission limits.	1-9
33.	The Permittee shall report its intent to conduct "Burn-out" maintenance to SWCAA a minimum of one business day prior to commencement.	1

No.	Reporting Requirements	Equipment/ Activity
34.	The following operational records for the glass melting furnace/annealing lehr shall be reported to SWCAA no later than 30 days after the end of each respective calendar quarter: (a) Hourly emissions data from each CEMS (lbs); (b) Hourly heat input (MMBtu); (c) Daily glass draw (tons); (d) Daily salt cake/silica sand consumption (lbs); and (e) Date and time of hot fan transition events.	1
35.	Emission test results shall be reported to SWCAA in writing within 45 days of test completion.	1, 3-8
36.	Hours of operation for approved dust collectors shall be reported to SWCAA no later than 30 days after the end of each respective calendar quarter.	3-8

3. General Provisions

No.	General Provisions
A.	For the purpose of ensuring compliance with this Permit, duly authorized representatives of the Southwest Clean Air Agency shall be permitted access to the permittee's premises and the facilities being constructed, owned, operated and/or maintained by the permittee for the purpose of inspecting said facilities. These inspections are required to determine the status of compliance with this Permit and applicable regulations and to perform or require such tests as may be deemed necessary.
B.	The provisions, terms and conditions of this Permit shall be deemed to bind the permittee, its officers, directors, agents, servants, employees, successors and assigns, and all persons, firms, and corporations acting under or for the permittee.
C.	The requirements of this Permit shall survive any transfer of ownership of the source or any portion thereof.
D.	This Permit shall be posted conspicuously at or be readily available near the source.
E.	This Permit shall be invalid if construction/installation has not commenced within eighteen months from date of issuance.
F.	This Permit does not supersede requirements of other Agencies with jurisdiction and further, this Permit does not relieve the permittee of any requirements of any other governmental Agency. In addition to this Permit, the permittee may be required to obtain permits or approvals from other agencies with jurisdiction.
G.	Compliance with the terms of this Permit does not relieve the permittee from the responsibility of compliance with SWCAA General Regulations for Air Pollution Sources, previously issued Regulatory Orders, RCW 70.94, Title 173 WAC or any other applicable emission control requirements, nor from the resulting liabilities and/or legal remedies for failure to comply.
H.	If any provision of this Permit is held to be invalid, all unaffected provisions of the Permit shall remain in effect and be enforceable.
I.	No change in this Permit shall be made or be effective except as may be specifically set forth by written order of the Southwest Clean Air Agency upon written application by the permittee for the relief sought.

No.	General Provisions
J.	The Southwest Clean Air Agency may, in accordance with RCW 70.94 impose such conditions as are reasonably necessary to assure the maintenance of compliance with the terms of this Permit, the Washington Clean Air Act, and the applicable rules and regulations adopted under the Washington Clean Air Act.

Air Discharge Permit 04-2568R2 - Appendix A
Emission Testing Requirements
Glass Melting Furnace

1. **Introduction:**
The purpose of this testing is to quantify emissions from the glass melting furnace, and demonstrate compliance with the requirements of this Permit and applicable air quality regulations.

2. **Testing Requirements:**

a. **Test plan.** A comprehensive test plan shall be submitted to SWCAA for review and approval at least 10 business days prior to testing. SWCAA personnel shall be informed at least five business days prior to testing so that a representative may be present during testing.

b. **Testing schedule.** An emission test shall be conducted at the exhaust stack of the glass melting furnace within 60 days of achieving maximum firing rate, but no later than 180 days after initial start-up.

c. **Test runs/Reference test methods.** A minimum of three (3) test runs shall be performed for each constituent listed below to ensure the data are representative. Compliance shall be demonstrated by averaging the results of the individual sampling runs. The sampling methods identified below shall be used unless alternate methods are approved in writing by SWCAA in advance of the emission testing.

Constituent	Reference Test Method	Minimum Test Run Duration
Flow rate, temperature	EPA Methods 1 and 2	N/A
O_2, CO_2 content	EPA Method 3 or 3A	60 minutes
Moisture content	EPA Method 4	60 minutes
Sulfuric acid	EPA Method 8	60 minutes
Total fluoride	EPA Method 26A	60 minutes

3. **Source Operation:**

a. **Source operations.** Furnace operation during emissions testing must be at no less than 90% of rated capacity.

b. **Record of production parameters.** Production related parameters and equipment operating conditions shall be recorded during emissions testing to correlate operating conditions with emissions. Recorded parameters shall, at a minimum, include furnace heat input, concurrent glass draw, and plant adjustments. All recorded production parameters shall be documented in the test results report.

4. **Reporting Requirements:**

a. A final emission test report shall be prepared and submitted to SWCAA within 45 calendar days of test completion and, at a minimum, shall contain the following information:
   (1) Description of the source including manufacturer, model number and design capacity of the equipment, and the location of the sample ports or test locations,
   (2) Time and date of the test and identification and qualifications of the personnel involved,
   (3) Summary of results, reported in units and averaging periods consistent with the application emissions standard or unit,
   (4) Summary of control system or equipment operating conditions,
   (5) Summary of production related parameters,
   (6) A description of the test methods or procedures used including all field data, quality assurance/quality control procedures and documentation,
   (7) A description of the analytical procedures used including all laboratory data, quality assurance/quality control procedures and documentation,
   (8) Copies of field data and example calculations,
   (9) Chain of custody information,
   (10) Calibration documentation,
   (11) Discussion of any abnormalities associated with the results, and
   (12) A statement signed by the senior management official of the testing firm certifying the validity of the source test report.

b. All test results shall be presented in units of pounds per hour (lb/hr) and pounds per ton of glass draw (lb/ton_g).

Air Discharge Permit 04-2568R2 - Appendix B
Emission Testing Requirements
EP Dust Baghouses

1. **Introduction:**
The purpose of this testing is to quantify emissions from baghouses with identified excess visible emissions, and demonstrate compliance with the requirements of this Permit.

2. **Testing Requirements:**

   a. **Testing schedule.** Each affected baghouse required by SWCAA to emission test due to excess visible emissions, shall be emission tested no later than 60 days following the source's receipt of the associated Notice of Violation. Periodic emission testing may also be required with a frequency not to exceed once every 60 months. Alternate testing schedules may be implemented if approved in writing by SWCAA in advance of the regularly scheduled test.

   b. **Test plan.** A comprehensive test plan shall be submitted to SWCAA for review and approval at least 10 business days prior to each test. SWCAA personnel shall be informed at least five business days prior to testing so that a representative may be present during testing.

   c. **Test runs/Reference test methods.** A minimum of three (3) test runs shall be performed for each constituent listed below to ensure the data are representative. Compliance shall be demonstrated by averaging the results of the individual sampling runs. The sampling methods identified below shall be used unless alternate methods are approved in writing by SWCAA in advance of the emission testing.

Constituent	Reference Test Method	Minimum Test Run Duration
Stack gas velocity, flow rate	EPA Methods 1 and 2	N/A
O_2, CO_2	EPA Method 3 or 3A	60 minutes
Moisture	EPA Method 4	60 minutes
PM	EPA Method 5 or 17	60 minutes
Opacity	SWCAA Method 9	20 minutes

3. **Source Operation:**

   a. **Source operations.** Source operations during the emissions test must be representative of maximum intended operating conditions.

   b. **Record of production parameters.** Production related parameters and equipment operating conditions shall be recorded during emissions testing to correlate operating conditions with emissions. All recorded production parameters shall be documented in the test results report. Recorded parameters shall, at a minimum, include the following:
      - Process startups and shutdowns
      - Process rate during testing
      - Material type handled during testing.

4. Reporting Requirements:

a. A final emission test report shall be prepared and submitted to SWCAA within 45 calendar days of test completion and, at a minimum, shall contain the following information:
   (1) Description of the source including manufacturer, model number and design capacity of the equipment, and the location of the sample ports or test locations,
   (2) Time and date of the test and identification and qualifications of the personnel involved,
   (3) Summary of results, reported in units and averaging periods consistent with the application emissions standard or unit,
   (4) Summary of control system or equipment operating conditions,
   (5) Summary of production related parameters,
   (6) A description of the test methods or procedures used including all field data, quality assurance/quality control procedures and documentation,
   (7) A description of the analytical procedures used including all laboratory data, quality assurance/quality control procedures and documentation,
   (8) Copies of field data and example calculations,
   (9) Chain of custody information,
   (10) Calibration documentation,
   (11) Discussion of any abnormalities associated with the results, and
   (12) A statement signed by the senior management official of the testing firm certifying the validity of the source test report.

b. All test results shall be presented in units of pounds per hour (lb/hr) and grains per dry standard cubic feet (gr/dscf).

Air Discharge Permit 04-2568R2 - Appendix C
Emission Testing Requirements
Cullet Return Baghouse #2

1. **Introduction:**
The purpose of this testing is to quantify emissions from cullet return baghouse #2, and demonstrate compliance with the requirements of this Permit.

2. **Testing Requirements:**

a. **Testing schedule.** Cullet return baghouse #2 shall be emission tested no later than 90 days after commencing initial operation. Subsequent emission testing shall be conducted every 60 months thereafter, no later than the month in which the initial test was performed. Alternate testing schedules may be implemented if approved in writing by SWCAA in advance of the regularly scheduled test.

b. **Test plan.** A comprehensive test plan shall be submitted to SWCAA for review and approval at least 10 business days prior to each test. SWCAA personnel shall be informed at least five business days prior to testing so that a representative may be present during testing.

c. **Test runs/Reference test methods.** A minimum of three (3) test runs shall be performed for each constituent listed below to ensure the data are representative. Compliance shall be demonstrated by averaging the results of the individual sampling runs. The sampling methods identified below shall be used unless alternate methods are approved in writing by SWCAA in advance of the emission testing.

Constituent	Reference Test Method	Minimum Test Run Duration
Stack gas velocity, flow rate	EPA Methods 1 and 2	N/A
O_2, CO_2	EPA Method 3 or 3A	60 minutes
Moisture	EPA Method 4	60 minutes
PM	EPA Method 5 or 17	60 minutes
Opacity	SWCAA Method 9	20 minutes

3. **Source Operation:**

a. **Source operations.** Source operations during the emissions test must be representative of maximum intended operating conditions.

b. **Record of production parameters.** Production related parameters and equipment operating conditions shall be recorded during emissions testing to correlate operating conditions with emissions. All recorded production parameters shall be documented in the test results report. Recorded parameters shall, at a minimum, include the following:
   - Process startups and shutdowns
   - Process rate during testing
   - Material type handled during testing.

4. Reporting Requirements:

a. A final emission test report shall be prepared and submitted to SWCAA within 45 calendar days of test completion and, at a minimum, shall contain the following information:

(1) Description of the source including manufacturer, model number and design capacity of the equipment, and the location of the sample ports or test locations,
(2) Time and date of the test and identification and qualifications of the personnel involved,
(3) Summary of results, reported in units and averaging periods consistent with the application emissions standard or unit,
(4) Summary of control system or equipment operating conditions,
(5) Summary of production related parameters,
(6) A description of the test methods or procedures used including all field data, quality assurance/quality control procedures and documentation,
(7) A description of the analytical procedures used including all laboratory data, quality assurance/quality control procedures and documentation,
(8) Copies of field data and example calculations,
(9) Chain of custody information,
(10) Calibration documentation,
(11) Discussion of any abnormalities associated with the results, and
(12) A statement signed by the senior management official of the testing firm certifying the validity of the source test report.

b. All test results shall be presented in units of pounds per hour (lb/hr) and grains per dry standard cubic feet (gr/dscf).

Clark
Cowlitz
Lewis
Skamania
Wahkiakum

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State Environmental Policy Act

DETERMINATION OF NONSIGNIFICANCE (DNS)

Description of proposal:

ADP Application L-627: Installation of two new glass packing lines and modification of existing visible emission limits for the facility's glass furnace. The new packing lines will be constructed inside an existing warehouse building using presently available utilities. The project will not involve new building construction, excavation or significant alteration of the building envelope. There will be little, or no, impact on external media other than air (water run-off, light, sound, traffic, etc.). A dust collection system with external baghouse will be installed as part of the project. Air emissions from this system will be controlled with high efficiency fabric filtration. Modification of existing visible emission limits for the furnace will only impact air emissions. The affected operating condition (hot fan load adjustment) is transitory in nature and not frequently encountered. The proposed modification will have a minimal impact on air emissions.

Proponent: Cardinal Pacific FG (Warren Krug, Environmental Engineer)

Location of proposal, including street address if any:
545 Avery Road in Winlock, Washington 98596

Lead agency: Southwest Clean Air Agency

The lead agency for this proposal has determined that it does not have a probable significant impact on the environment. An environmental impact statement (EIS) is not required under RCW 43.21C.030(2)(c). This decision was made after review of a completed environmental checklist and other information on file with the lead agency. This information is available to the public on request.

☒ **There is no comment period for this DNS.**

☐ **This DNS is issued under WAC 197-11-340(2); the lead agency will not act on this proposal for 15 days from the date below. Comments must be submitted by ______.**

Responsible official: Paul T. Mairose, P.E.
Position/title: Chief Engineer

Address: Southwest Clean Air Agency
11815 NE 99 St., Ste 1294
Vancouver, WA 98682-2322
Phone: (360) 574-3058 ext 30

Signature: Paul T Mairose

Date: 12/16/08

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

by Vicki Stamper & Megan Williams

March 6, 2020

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.

Table of Contents

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.
>
> . . .

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

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[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

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[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

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[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. . . .

[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]

<u>Application of NSCR to rich-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 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

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[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.

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[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]

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

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.

Application of LEC to lean-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 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

[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.

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[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

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

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

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[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.

[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) **<u>or</u>** 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.

[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 NOx 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 NOx levels, such rates of injection may reduce NOx 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

[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]

Water Injection/Gas Turbines:

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

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

Steam Injection/Gas Turbines:

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

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

[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

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[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

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[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.

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[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	5-50 MMBtu	42 ppmv or 2.12 lb/MWhr
	Effective 1/1/2010:	>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 Effective 12/31/95:	>0.3-2.9 MW	25 (reference limit) x EFF/25%[372]
		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
	Currently proposed revisions: 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),

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

[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

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[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

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[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]

[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]

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[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

[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]

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[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.

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[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.

[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

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[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

[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]

[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

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[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)(lll)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

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[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

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
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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
Chief, Policy, Planning, and Permit Revue Branch

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ARD-DEN:DShepherd:2075: 4/19/2017:Tesoro CPUP Ecology

catalysts

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.

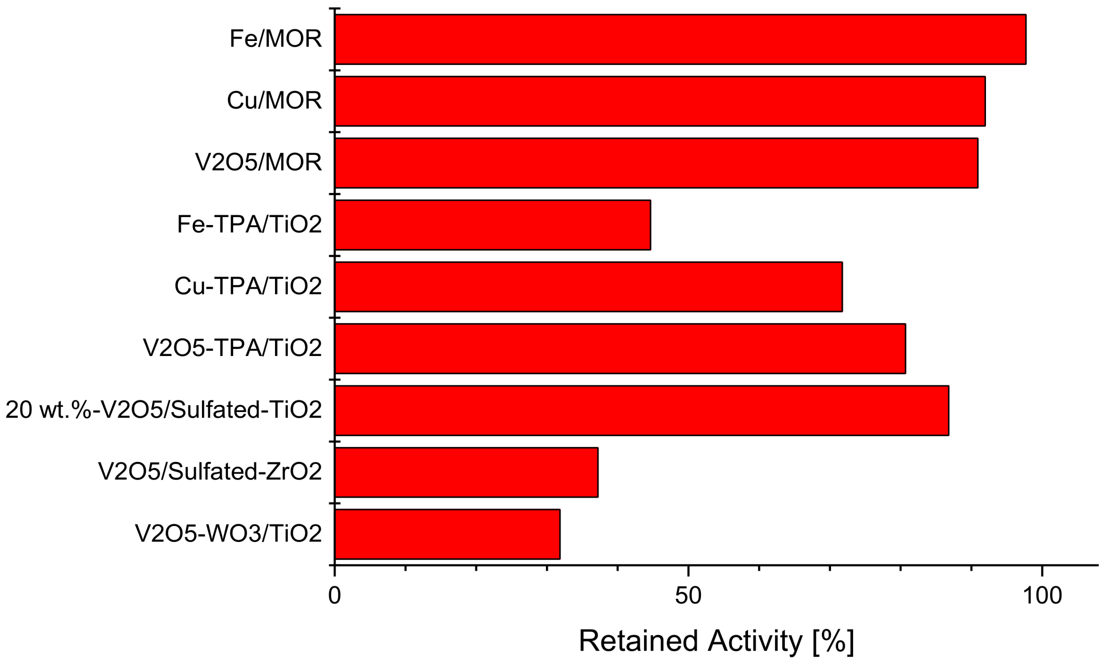

Figure 1. Retained activity at 400 °C upon impregnation with 100 µmol K $g_{catalyst}^{-1}$. (130 µmol K $g_{catalyst}^{-1}$ for V_2O_5/sulfated-ZrO_2). Reproduced from [47].

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.

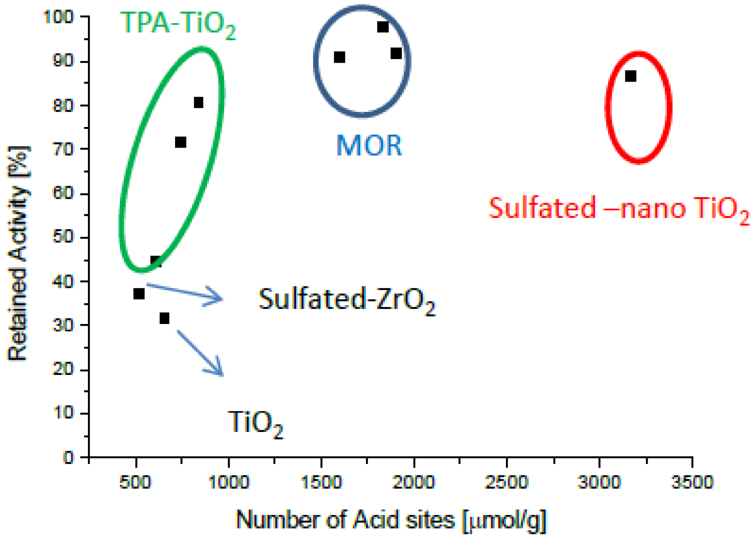

Figure 2. Retained activity at 400 °C upon impregnation with 100 µmol K $g_{catalyst}^{-1}$ (130 µmol K $g_{catalyst}^{-1}$ for V_2O_5/sulfated-ZrO_2) as a function of the number of acid sites of fresh catalysts. Generated with data from [47].

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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