Appendix A

BACT for Various Emission Units at Stationary Sources

DAQ-2018-007161

Introduction

The DAQ must perform a BACT review for all major sources within the $PM_{2.5}$ nonattainment areas in the State of Utah. As part of this review, the DAQ found that several sources had similar smaller emission units. DAQ has consolidated the review of these smaller emission units into this document.

Each emission unit is addressed in its own section. Each section includes a brief description of the emission unit and the estimated emissions from the emission unit. Since emission units may vary in capacity and emission rates, the DAQ made several assumptions in determining emission estimates. In certain cases, emission factors were used instead of hourly or annual emission rates.

The BACT analysis for each emission unit includes the five steps in a top-down BACT analysis. The first step identifies control options. DAQ evaluated various resources to identify the various controls and emission rates. These include, but are not limited to, federal regulations, Utah regulations, regulations of other states, RBLC, issued permits, and emission unit vendors.

The second step in the BACT analysis eliminates the technological infeasible options. The remaining control options are ranked in the third step of the BACT analysis. Combinations of various controls are also included. The fourth step of the BACT analysis evaluates the economic feasibility of the highest ranked option. This evaluation includes energy, environmental, and economic impacts of the control option.

The fifth step in the BACT analysis selects the “best” option. This step also includes the necessary justification to support the DAQ’s decision. The DAQ has included the time it will take for a source to implement the selected control if the control is not already being implemented at the source.

Table of Contents

Acronyms

AP-42	EPA's Compilation of Air Pollutant Emission Factors
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
Btu	British Thermal Unit
CFM	Cubic Feet per Minute
DAQ	Utah Division of Air Quality
dscf	Dry Standard Cubic Foot
dscm	Dry Standard Cubic Meter
EPA	United States Environmental Protection Agency
FGR	Flue Gas Recirculation
ft^3	Cubic Foot
g	gram
gal	Gallon
gr	grain
HAP	Hazardous Air Pollutant
HDPE	High-Density Polyethylene
hp	Horsepower
hr	Hour
L	liter
lb	Pound
MACT	Maximum Achievable Control Technology
mg	milligram

MMBtu	Million British Thermal Unit
N_2	Nitrogen
NAPAP	National Acid Precipitation Assessment Program
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	Oxides of Nitrogen
NSCR	Nonselective Catalytic Reduction
NSPS	New Source Performance Standards
O_2	Oxygen
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns
$PM_{2.5}$	Particulate Matter less than 2.5 microns
ppbw	Parts per Billion by Weight
ppm	Parts per Million
ppmv	Parts per Million by Volume
ppmw	Parts per Million by Weight
PTE	Potential to Emit
PTFE	Polytetrafluoroethylene
RBLC	RACT/BACT/LAER Clearinghouse
SCAQMD	South Coast Air Quality Management District
scf	Standard Cubic Foot
SCR	Selective Catalytic Reduction
SI	Spark Ignition
SIP	State Implementation Plan

SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	Sulfur Dioxide
tpy	Ton per Year
TDS	Total Dissolved Solid
UAC	Utah Administrative Code
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

1. - Abrasive Cleaning/Blasting

1.1 - Description:

Abrasive blasting is the use of an abrasive material to clean or texturize a material, such as metal or masonry. Abrasive blasting is often used to remove rust, scale, and coatings from equipment, vehicles, bridges, etc. UAC defines abrasive blasting in R307-206 and R307-306 as "the operation of cleaning or preparing a surface by forcibly propelling a stream of abrasive material against the surface."

Abrasive blasting can be conducted by air pressure, centrifugal wheels, or water pressure. Air pressure systems use compressed air to propel the abrasive material. Centrifugal wheel systems use a rotating impeller to mechanically propel the abrasive material. Water pressure systems use air or water pressure to propel abrasive slurry (USEPA, 1997b).

A wide range of materials is used as abrasive materials:

- Sand is the most commonly used abrasive material. Sand has a high breakdown rate and generates significant particulate emissions. Silica sand is less effective but is used in unconfined abrasive blasting operations, where capturing emissions is not feasible.
- Metallic abrasive material consists of cast iron shot, cast iron grit, and steel shot. These materials can be reclaimed and reused.
- Synthetic abrasive materials include silicon carbide and aluminum oxide. These materials are more durable and create less dust than sand. These materials can be reclaimed and reused.
- Other materials include mineral abrasives, cut plastic, glass beads, crushed glass, and nutshells. These materials can usually be reclaimed and reused.

Air pressure systems typically use sand, metallic materials, or aluminum oxide. Wet blasters typically use material that will remain suspended in water, such as glass beads or sand (USEPA, 1997b).

1.2 - Emissions Summary:

Abrasive blasting emissions consist of PM and HAP. Heavy metal constituents, such as Chromium, Manganese, Nickel, Lead, Iron, and Barium can be found in abrasive materials depending on the surface that it was applied to or the material used for blasting (USEPA, 1997b).

Table 1 below summarizes the emission factors included in Table 13.2.6-1 of EPA AP-42 Chapter 13.2.6. Specific emissions were not estimated because emissions will vary significantly depending on the process, blasting material, and surface being blasted.

Table 1. AP-42 Emission Factors		
Abrasive Type	**Particle Size**	**Emission Factor (lb/1,000 lb abrasive)**
Sand blasting of mild steel panels	Total PM - 5 mph wind speed	27
	Total PM - 10 mph wind speed	55
	Total PM - 15 mph wind speed	91
	PM_{10}	13
	$PM_{2.5}$	1.3
Abrasive blasting of unspecified metal parts, controlled with a fabric filter	Total PM	0.69

1.3 - Control Options:

This BACT analysis was performed for control options for $PM_{2.5}$ emissions. The following sources were evaluated to identify control options for abrasive blasting.

- EPA's RBLC
- Technical documents and EPA fact sheets, EPA Air Pollution Control Cost Manual
- NSPS, NESHAP, and MACT regulations
- Utah State Rules
- SJVAPCD Current Rules and BACT Clearinghouse
- SCAQMD Current Rules
- BAAQMD Current Rules

RBLC and Technical Documents

No control options were identified in the RBLC database. The following control options were identified from technical documents as potential controls for $PM_{2.5}$ emissions from abrasive blasting:

Blast Enclosures Controlled By Baghouses

Enclosed abrasive blasting operations are conducted in a confined area designed to contain blast debris and restrict pollutants from being emitted to the atmosphere. Emissions are vented through a baghouse prior to being discharged to the atmosphere. This is a common control used in a variety of applications (USEPA, 1997a).

Reclaim Systems

Reclaim systems capture abrasive media and debris. The abrasive media in these systems can be reused. These systems are typically found in vacuum blasters. Vacuum blasters collect surface coatings and abrasive blasting materials with a capture and collection system surrounding the blast nozzle (USEPA, 1997a).

Drapes or Curtains

This control consists of drapes or curtains installed around the blast area to contain blasting media and debris. These curtains are available in a variety of materials (HDPE, polyester, or fabric) and can be installed in a variety of configurations. Drapes are relatively inexpensive but are not very effective. This technique is commonly applied to unconfined blasting operations or for large items (USEPA, 1997a).

Water Curtains

Water curtains consist of a series of nozzles installed around the blasting area. Water is sprayed downward confining the blasting media and debris to the area enclosed by the nozzles and washing down the blasting media and debris to the ground. This technique is highly effective but consumes a lot of water. Furthermore, the water and washed out debris requires an additional clean-up or collection system (USEPA, 1997a).

Wet Blasting

Wet blasting systems use high pressure water alone or high pressure water combined with an abrasive media. Abrasive media typically used in wet blasting consists of materials that will remain suspended in water, such as glass beads or sand (USEPA, 1997a).

Use of Low Dust Abrasives

Low dust abrasives include coal slag, copper slag, nickel slag, steel grit, steel shot, or other media with a free silica content of less than 1.0% (TCEQ, 2015)

NSPS, NESHAP, or MACT Regulations

40 CFR 63 Subpart XXXXXX (National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Nine Metal Fabrication and Finishing Source Categories; Final Rule) applies to any new or existing source that performs metal fabrication or finishing operations which uses or emits compounds of cadmium, chromium, lead, manganese, and nickel; or uses or emits elemental forms of all except lead. This subpart requires that vented enclosures be controlled by a filtration device and defines management practices for vented enclosures [63.11516(a)(2)(ii)]. This subpart allows blasting of large objects (i.e. greater than 8 feet in any dimension) to be conducted in an unconfined enclosure as long as: measures are taken to reduce excess dust, abrasive material is enclosed in storage areas and holding bins, blasting media is reused if possible, and low PM-blasting media is used if an appropriate surrogate is available.

Utah State Rules

UAC R307-306 (PM_{10} Nonattainment and Maintenance Areas: Abrasive Blasting) limits visible emissions from abrasive blasting operations to less than 20% opacity except for an aggregate period of three minutes in one hour. Visible emissions may be limited to less than 40% opacity for abrasive blasting operations that use confined blasting, wet abrasive blasting, hydroblasting, or unconfined blasting using the abrasives defined in R307-306-6(2).

Other State Rules

The SJVAPCD BACT database lists a dust collector with a fabric or cartridge filter as BACT for abrasive blasting operations.

SJVAPCD refers to California Code or Regulations (CCR §92200 through § 92540). CCR §92200 limits visible emissions from the abrasive blasting to less than 40% for blasting operations conducted outside a permanent building and to less than 20% for blasting operations conducted within a permanent building.

CCR § 92500 states that abrasive blasting must be conducted within a permanent building except if steel or iron shot/grit is used exclusively; the item to be blasted exceeds 8 feet in any dimension; or the surface being blasted is situated at its permanent location. Abrasive blasting conducted outside a permanent building must be conducted using wet abrasive blasting, hydroblasting, vacuum blasting, or abrasives certified by CARB.

SCAQMD Rule 1140 (Abrasive Blasting) and BAAQMD Rule 12-4-100 have similar requirements to CCR §92200 through § 92540.

1.4 - Technological Feasibility:

The control options described above are generally technically feasible for a variety of blasting applications. A blast enclosure controlled by a baghouse is commonly used. Many of the blasting operations conducted at major sources in the $PM_{2.5}$ nonattainment area are conducted in an enclosure controlled by a baghouse.

The remaining control options (reclaim systems, drapes, wet blasting, low dust abrasives) are common control options for unconfined blasting or confined blasting not controlled by a baghouse. Potential considerations with these controls are the following:

- Vacuum blasters are commonly used in uncontrolled confined blasting operations (Western Regional Air Partnership, 2006).
- Blasting drapes are relatively inexpensive and easy to implement, but are not very effective because blast debris may escape through gaps or penetrate the porous material of the drapes (USEPA, 1997b).
- Water curtains are highly effective but consume a lot of water. This technique also requires additional maintenance to manage the water and washed-out debris (USEPA, 1997a).
- Wet blasting control efficiencies of 50% and 93% have been reported (USEPA, 1997b)

1.5 - Ranking of Individual and Combined Controls:

The identified control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1. Blast enclosure with baghouse
2. Blasters with reclaim systems
3. Wet blasting
4. Water curtains
5. Blasting drapes
6. Low dust abrasives

1.6 - Economic Feasibility:

The costs of abrasive blasting controls vary significantly depending on the type of application, blasting frequency, pressure requirements, blasting material type and usage, and extent of operations.

The capital costs for blast enclosures and baghouses vary significantly depending on the type of equipment being blasted, physical limitations at the source, blasting material, etc.

The capital costs of blasters with reclaim systems ranges between $13,000 and $200,000 depending on pressure requirements. Wet blaster costs range from $16,000 to $112,000. Blasting drapes are relatively inexpensive (approximately $300 for a 200-foot roll) but price varies significantly depending on the material and application (Kitchen, 2017).

The costs of each control option depend on the specific requirements of each abrasive blasting operation. This BACT analysis is intended to be a general evaluation of the control options available for each emission source and is not an evaluation of the specific emission unit in operation. Therefore, an economic feasibility evaluation was not prepared for this BACT analysis.

1.7 - Evaluation of Findings & Control Selection:

The majority of blasting operations conducted at major sources in the $PM_{2.5}$ nonattainment area are enclosed and controlled by a baghouse.

BACT for $PM_{2.5}$ emissions from abrasive blasting operations is to conduct blasting in an enclosed area controlled by a baghouse. BACT for baghouses is discussed in Section 3.

Unconfined abrasive blasting operations may only be conducted if the item to be blasted exceeds 8 feet in any dimension or the surface being blasted is situated at its permanent location. Unconfined abrasive blasting must be conducted using wet abrasive blasting, blasting with reclaim systems, or the abrasives defined in R307-306-6(2).

1.8 - Time for Implementation:

As previously stated, the economic viability of upgrading controls on blasting operations can vary significantly based on operating requirements. An evaluation of the blasting operations that do not meet the BACT determinations stated above shall be conducted to determine whether blasting controls can be upgraded. If this evaluation shows that it is economically feasible to upgrade blasting controls to meet BACT, controls shall be installed and operational within one year of the date of this document.

2. - Ammonia Emissions from SCRs

2.1 - Description:

This source category describes ammonia emissions, called ammonia slip, that emit from SCR technology. SCR technology is used to control NO_X emissions from processes, and is typically found on large stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. The SCR process works by chemically reducing the NO_X molecule in an emission stream into molecular nitrogen and water vapor. A reagent such as ammonia or urea is injected into the ductwork downstream of the combustion unit, which mixes with the waste gas, and the mixture enters a catalyst. The mixture diffuses through the catalyst, and reacts selectively with the NO_X to reduce emissions. This reaction occurs on a 1:1 basis; however, to adequately control NO_X emissions, an excess of reagent must be used. This excess results in ammonia slip. Ammonia slip increases over time as the catalyst degrades.

2.2 - Emissions Summary:

Several sources in the State of Utah use SCR technology to control NO_X emissions. SCR at these sources control combustion gas turbines for power generation. Several use aqueous ammonia in the SCR technology, while others use aqueous urea and an in-line ammonia generator.

The use of SCR technology can result in emissions of ammonia. The DAQ estimated emissions from SCR technology using sample emission calculations from one source in Utah. These sample emission calculations estimated ammonia emissions in lb/hr using a mass emission rate calculation with the following variables: normal fuel flow rate in MMBtu/hr; ammonia emissions of 10 ppm; an ideal gas density in scf/lb-mol; the molecular weight of ammonia in lbm/lb-mol; and a Method 19 F Factor in dscf/MMBtu. Using this method, the DAQ determined emissions from a large source using SCR technology is approximately 33.57 pounds of ammonia emitted per hour. An intermittent baseload plant operating at 7,000 hours would emit 117 tpy of ammonia, and a peaking plant operating at 650 hours would emit 10.91 tpy of ammonia.

2.3 - Control Options:

The following sources were reviewed to identify available control technologies:

- EPA's RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA's Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state and federal regulations
- Various state-specific example permits and BACT analyses
- A thorough literature search using the Google search engine

Control Options for Ammonia:

Efficient SCR catalyst capable of achieving ammonia slip $\leq$ 5 ppm at 3% O_2 (South Coast Air Quality Management District, 2014)
Ammonia Slip Catalysts (Johnson Matthey Stationary Emissions Control, 2017)

2.4 - <u>Technological Feasibility:</u>

Control Options for Ammonia:

Efficient SCR catalyst capable of achieving ammonia slip ≤ 5 ppm at 3% O_2

Many modern catalysts are manufacturer-rated for 5 ppm at 3% O_2 ammonia slip down to 2 ppm at 3% O_2 ammonia slip from SCR technology. These ammonia limits are BACT determinations made by the SCAQMD (South Coast Air Quality Management District, 2014). Therefore, this control option is technically feasible.

Ammonia Slip Catalysts

The DAQ conducted a search using the Google search engine, state permits and BACT analyses, and EPA's RBLC for ammonia slip catalysts used in industry to control ammonia emissions from SCRs. While examples exist for mobile diesel emissions, the DAQ could not find any examples of industrial sources like those in this source category using ammonia slip catalysts. Therefore, this control option is not technically feasible because it has not been proven in an industrial setting to reduce ammonia emissions.

2.5 - <u>Ranking of Individual and Combined Controls:</u>

Control Options for Ammonia:

1. Efficient SCR catalyst capable of achieving ammonia slip ≤ 5 ppm at 3% O_2:
    - The installation of a more efficient SCR catalyst would ensure ammonia emissions would decrease. A SCR with ammonia slip ≤ 5 ppm at 3% O_2 catalyst would reduce ammonia emissions by 50%, and a SCR with ammonia slip ≤ 2 ppm at 3% O_2 catalyst would reduce ammonia emissions by up to 80%. Both reductions are based on emissions starting at 10 ppm of ammonia.

2.6 - <u>Economic Feasibility:</u>

Efficient SCR catalyst capable of achieving ammonia slip ≤ 5 ppm at 3% O_2:

- Many newer SCR catalysts have a manufacturer guarantee of 5 ppm or less of ammonia slip; however, the installation of a SCR catalyst with a lower ammonia slip requires a larger volume of catalyst per catalyst module. Therefore, the installation of a more efficient SCR catalyst would require design reconfiguration costs as well as catalyst replacement costs (John L. Sorrels, 2015).
- Based on the feasibility and cost impact conducted by Utah Municipal Power Agency, the cost to update the SCR system is $350,000 to $500,000 per SCR system (Melissa Armer, P.E., 2017).

The following assumptions were used in this analysis:

- The average cost per SCR system is $425,000
- An average of four SCR systems at each source
- An annual interest rate of 7% (United States Environmental Protection Agency, 2002)
- The economic life of each unit is 10 years
- Negligible annual maintenance costs due to costs most likely being similar to current costs with the current SCR systems

Based on these assumptions, the cost/ton removed for installing efficient SCR catalysts is as follows:

- $2,244 for intermittent baseload plant operating 7,000 hours a year
- $24,064 for peaking plant operating 650 hours a year.

For a baseload plant that operates 80% of the year, replacing an older SCR catalyst with a newer SCR catalyst is economically feasible. For a peaking plant that only operates minimally throughout the year, replacing an older SCR catalyst with a newer SCR catalyst is not economically feasible.

2.7 - Evaluation of Findings & Control Selection:

The DAQ recommends as BACT for sources that operate 80% of the year or more the installation of a more efficient SCR catalyst capable of achieving ammonia slip levels of 5 ppm at 3% O_2. To guarantee a source is meeting this emission limitation, the DAQ recommends that testing be done within 180 days after issuance of a permit with an emission limitation, and yearly thereafter. In lieu of testing, a source can decide to use a continuous emissions monitoring system to measure ammonia emissions from SCR technology.

2.8 - Time for Implementation:

If a source does not currently have a SCR catalyst rated to meet a level of 5 ppm ammonia slip at 3% O_2, the DAQ recommends 180 days up to one year to replace an existing SCR catalyst with a newer catalyst (Melissa Armer, P.E., 2017).

3. - Baghouse Dust Collector

3.1 - Description:

Baghouses are used at a source to control particulate emissions. Pollutant laden air is forced through a chamber containing fabric filters (bags), which capture and remove particulates. Baghouses contain groups of fabric bags. The porous openings in the fabric bags allow air to flow through the bags but prevent particulate matter from passing through the bags. Systems also include a collection hopper that stores collected dust until the dust can be removed ("EPA-CICA Fact Sheet- Fabric Filters"). The number of bags in a baghouse is dependent on size, airflow (cfm), and air-to-cloth ratio design requirements.

Baghouse operations are dependent on the air pressure through the system; therefore, pressure drop parameters are monitored to ensure proper airflow. As the pressure moves out of the designated range, the bags are cleaned in one of two ways. Reverse-air baghouses use a reverse airflow to push captured particulates into a collection system. Pulsejet baghouses target individual bags within the baghouse with pulsed air to clean individual bags("APTI: Baghouse Plan Review," 1982).

Baghouses are used as a control device for multiple applications across many industries. State and federal regulations for baghouses are dependent on the type of operations controlled. Specific requirements are dependent on the federal and state applicability to these operations. For example, 40 CFR 63 subpart X, §63.548, specifies requirements for baghouses controlling lead smelting. The subpart requires best practices, including a source baghouse leak procedure. The procedures for these sources include daily pressure gauge inspections, weekly visual inspections of the dust collection hoppers, and quarterly inspections of the physical integrity of the bags and fans ("40 CFR 63.548").

3.2 - Emissions Summary:

Baghouses are designed to capture and control PM_{10} and $PM_{2.5}$ emissions. Since no baghouse is 100% efficient, remnant particulates vent through the baghouse vents ("EPA-CICA Fact Sheet-Fabric Filters"). An estimated 1.0% of emissions may escape out of the baghouse.

3.3 - Control Options:

Baghouses are considered a control for multiple source categories. There are no federal or state requirements that regulate baghouse selection or filter type. Typically, baghouse filters are rated with a control efficiency of 99%. Therefore, one percent of a source's emissions are vented into ambient air.

Potential controls for the emitted particulates include using a more efficient filter in the baghouse. While fabric filters are typically rated at 99% efficiency, newer filters are available with a rating at 99.9% ("San Joaquin SIP," 2015,"PTFE Membrane Baghouse Filters," 2017).

3.4 - Technological Feasibility:

Replacing bags after wear and tear or at the end of a bag's lifespan is the normal procedure for a baghouse. Baghouse filters have a manufacturer recommended replacement date. In addition, filters may require replacement for potential operating failures. The replacement of polyester bags with high efficiency bags can be implemented during this change. However, based on phone conversations in July of 2017 with the company U.S. Air Filtration, Inc. (U.S Air) and Utah sources, different systems have different operational needs. According to U.S. Air, high efficiency filters such as PTFE bags operate with a different air-to-cloth ratio than the traditional system setups. Because of this difference, a greater differential pressure is present with high efficiency bags. U.S. Air, a company that specializes in filter setups, notes that these bags cannot operate within systems already designed to operate under high pressure.

Companies such as Utah-based Nucor Steel operate multiple types of baghouses at their source. They note that high efficiency bags are possible options for bag replacements in such baghouse systems as the lime silo baghouses. However, the company notes that these bags could not be used in their baghouses designed to capture woodworking scraps. Due to the abrasive nature of the wood scraps, these bags would wear quickly and cause operational issues within the baghouse.

Therefore while a new, more efficient, bag is preferable in some operations, the new bags may be technical infeasibility in others. In the case of infeasibility, baghouses and baghouse filters should be operated and maintained according to manufacturer's instructions.

3.5 - Ranking of Individual and Combined Controls:

The use of 99.9% efficient filters is more efficient than the 99% fabric filters in controlling PM emissions. Proper maintenance and operation ensures that the baghouse is meeting the intended efficiency controls.

3.6 - Economic Feasibility:

The SJVAPCD SIP estimated the cost of switching bags to more efficient filter bags. A control efficiency of 99.9% can be achieved by using PTFE filter bags. Any bag meeting this control efficiency is acceptable, but costs were derived from PTFE bags. The analysis incorporates an assumption of a 2-year lifespan for each bag and 185 bags per baghouse. U.S. Air Filtration Inc. estimates that, on average, PTFE bags cost twice as much as polyester bags. Nucor Steel is permitted for a 1.4 million CFM baghouse with 4,032 bags. Each bag in the permitted baghouse currently costs $250.

Cost to Implement High Efficiency Bags

185 bags* x ($23/ 99.9% bag - $12/ polyester bag)/ 2 years = $1,017.5/year (per baghouse)
4,032 bags x ($500/99.9% bag- $250/ polyester bag)/ 2 years= $504,000/year (per baghouse)

Potential $PM_{2.5}$ Emission Reductions from Using High Efficiency Bags

The control efficiency for $PM_{2.5}$ for polyester bags is assumed to be equivalent to the control efficiency for PM_{10}.
(99.9% control efficiency – 99% control efficiency (polyester bags)) = 0.9% additional control

Emissions per baghouse are based on an assumed 75,000 CFM air flow vs. 1.4 Million CFM

Assuming 8,760 operation with 0.016 gr/scf PM_{10} and $PM_{2.5}$ ("Air Emissions: Dust Control")
The yearly emissions at 75,000 CFM at 99% control are 0.45 tons/year and 0.045 tons/year at 99.9% control of PM_{10} and $PM_{2.5}$
(0.45 tons/year) - (0.045 additional control from using PTFE bags)= **0.41 tons/year reduced**

The yearly emissions at 1.4 million CFM are permitted at 20.06 tons/year (Dean, 2006)
20.06 tons/year *0.9% reduced = **18.05 tons/year reduced**

<u>Potential Cost Effectiveness of Using High Efficiency Bags</u>
For a 185-bag baghouse: ($1,017.5/year) / (.41 tons/year reduced) = $2,481.71/ton
For Nucor Steel: ($504,000/year)/(18.05 tons/year)= $27,922.44/ton

99.9% control efficiency bags are a cost effective alternative to standard bags depending on the operation. The small additional control gains are enough to justify the implementation of more efficient filter bags as BACT in certain operations.

3.7 - Evaluation of Findings & Control Selection:

In some cases, using a more efficient filter is a cost effective, technically feasible control option that reduces particulate emissions. The higher efficiency filter bags require no additional operational or maintenance changes. The increased efficiency bags will reduce emissions and are considered BACT for this operation.

However, there are other operations where a higher efficiency bag is not technically feasible and/or cost effective.

Each site must evaluate the feasibility based on operation type and design.

In all operations, to ensure control efficiencies, operators must follow manufacturer recommended operation and maintenance. This includes monitoring and maintaining the pressure drop across filter bags, cleaning the filters, and replacing the filters as needed. This is considered standard practice for baghouse operations. (State of New Jersey Department of Environmental Protection, 2011).

In 40 CRF 63 Subpart X, §63.548, best practices include the development of a source baghouse leak procedure. The procedure includes daily pressure gauge inspections, weekly visual inspections of the dust collection hoppers, and quarterly inspections of the physical integrity of the bags and fans (“40 CFR 63.548”). This procedure could be implemented to all source categories using baghouses for controls.

3.8 - Time for Implementation:

New sources that determine filters rated at 99.9% efficiency are technically feasible and cost effective should begin use at start up or AO issuance. Existing sources that meet the criteria should begin use within 180 days. All sources should always follow manufacturer operational and maintenance specifications.

4. - Cold Solvent Degreasing Washers

4.1 - Description:

Solvent degreasers are used to remove various contaminants from pieces of equipment. Solvent degreasing is the physical process of using an organic or inorganic solvent to remove tars, greases, fats, oils, waxes, or soil from metal, plastic, printed circuit boards, or other surfaces. This cleaning is typically done prior to such processes as painting, plating, heat treating, and machining, or as part of maintenance operations. The solvent containers can be horizontal or vertical. The solvent may be agitated. Agitation increases the cleaning efficiency of the solvent. Agitation can be used with pumping, compressed air, vertical motion, or ultrasonics. (“197711_voc_epa450_2-77-022_solvent_metal_cleaning.pdf,” 1977) (“Document Display | NEPIS | US EPA,” 2002) (“ZyPDF.pdf,” 1979)

4.2 - Emissions Summary:

VOC emissions vary by the equipment features and operating practices of the cold-solvent degreaser. Emissions can also vary by what substance is in the cold-solvent degreaser.

4.3 - Control Options:

This BACT analysis was performed for control options for VOC emissions.

The source was searched on the “Point Source Control Strategies by Source Specific BACT Analysis,” on the DAQ’s website. Kennecott (Rio Tinto) listed cold-solvent degreasing operations. The lids on the cold-solvent degreasers are kept closed at all times to minimize emissions.

The State of Utah has regulations and requirements that apply to this activity.

- UAC R307-335, Degreasing and Solvent Cleaning Operations
    - UAC R307-335-4, Cold Cleaning Facilities
        - The degreaser’s cover must remain closed except during loading, unloading, or handling of part in the cleaner
        - Each degreaser must have an internal draining rack
        - Solvent must be stored in covered containers
        - Tanks, containers, and equipment must be maintained in good operating condition
        - If the solvent pressure is greater than 4.3 kPa measured at 38 degrees C, one of the options must be followed:
            - Freeboard ratio is greater than 0.7
            - Water cover if the solvent is insoluble in and heavier than water
            - Other control like refrigerated chiller or carbon adsorption

Options for the control of VOC are as follows:

- Carbon adsorption
- Refrigerated primary condensers
- Increased freeboard ratio
- Combination of covers

- Water covers
- Internal Draining Rack
- Spray hose/spray nozzle
- Reduced room drafts
- Selected operation and maintenance practices

("Document Display | NEPIS | US EPA," 2002), ("197711_voc_epa450_2-77-022_solvent_metal_cleaning.pdf," 1977), ("DAQ-2017-006637.pdf," February 1, 2017)

4.4 - Technological Feasibility:

The control options described above are technically feasible for cold-solvent degreasers.

4.5 - Ranking of Individual and Combined Controls:

1. Refrigerated primary condensers
2. Carbon adsorption
3. Increased freeboard ratio
4. Combination of covers
5. Water covers
6. Internal Draining Rack
7. Spray hose/spray nozzle
8. Reduced room drafts
9. Selected operation and maintenance practices

Various combinations of the above controls can be used.("c4s06.pdf," 1995)

4.6 - Economic Feasibility:

The costs of controls for cold-solvent degreasers vary significantly depending on the type and size of application and the solvent in the degreaser. Covers are one of the most cost effective options to reduce VOC emissions from cold solvent degreasers. Add-on control technologies may be cost prohibitive depending on the amount of VOC emissions. R307-335 has various requirement for degreasers. The control options listed in R307-335 are cost effective.

4.7 - Evaluation of Findings & Control Selection:

Compliance with the requirements of R307-335 is considered BACT for solvent degreasers.

4.8 - Time for Implementation:

All new sources must comply with R307-335 upon startup, and all existing sources must currently comply with R307-335.

5. - Combustion

5.1 - Description:

This section includes various emission units that combust fuel to provide thermal energy. The emission units in this section include: Ovens, Boilers, and Space Heaters.

5A. - Drying Oven - Briquette

5A.1 - Description:

Drying ovens are used to dry or cure a variety of products, such as asphalt, concrete, plastics, food products, paints, and fabric. These ovens typically use natural gas as fuel, but fuel oil may also be used. There are two sources of emissions from drying ovens – combustion emissions and emissions from the drying process.

Ovens are generally separated into two categories: direct-fired and indirect-fired ovens. In direct-fired ovens, the products of combustion mix directly with recirculated air and the load is subject to the products of combustion. In indirect-fired ovens, the products of combustions are contained in a heat exchanger and the load is not subject to the product of combustion (SCAQMD, 2016).

This BACT analysis focuses on natural gas-fired ovens and dryers used to dry minerals, steel products, paints, and metal concentrates.

5A.2 - Emissions Summary:

Factors affecting emissions include type and quantity of fuel burned, type of material being dried, and design capacity (input and output rates).

This BACT analysis will focus on natural gas-fired ovens. The primary pollutants from the combustion of natural gas in drying ovens are NO_X and CO. Particulates, SO_2, VOC, and HAP are emitted at lower levels (USEPA, 1998).

The types of pollutants and emission rates generated from the drying process vary by the type of material being heated. The most common types of emissions are PM, VOC, and HAP. The potential sources of PM emissions from drying ovens include the food industry, smelters, foundries, and aggregate industry. VOC emissions from drying ovens are generated from curing paints or plastic products. HAP emissions from drying ovens are generated from curing paints or plastic products, as well as smelters and foundries (metallic HAP). Specific emissions from the drying process were not estimated because emissions will vary significantly depending on the industrial process, the type of material being heated, and throughput. However, Table 1 lists some of the emission factors available in AP-42 for different types of industries.

Table 1. Representative Emissions from Drying Ovens				
		Drying Process Emission Factors (lb of pollutant/ton of material processed)		
Pollutant	**Natural Gas Combustion[1,2,3]**	**Metal Concentrate [4]**	**Paint Processes[5]**	**Grain Dryers[6]**
NO_X	2.15			
CO	1.80			
PM_{10}	0.16	12		0.055 – 0.75
$PM_{2.5}$	0.16			0.0094 – 0.13
SO_2	0.01			
VOC	0.12		100% VOC emitted	
HAP	0.04		100% HAP emitted	

[1]Burner size 5 MMBtu/hr
[2]Burner assumed to operate 8,760 hours per year
[3]Uncontrolled emission factors from AP-42, Chapter 1.4.
[4] Emission factors from AP-42, Chapter 11.24.
[5]Typical assumptions.
[6]Emission factors from AP-42, Chapter 9.9.

5A.3 - Control Options:

This BACT analysis was performed for control options for $PM_{2.5}$ and $PM_{2.5}$ precursors (NO_X, SO_2, VOC, and ammonia). Available control options are described for each pollutant evaluated.

The following sources were evaluated to identify control options for drying ovens.

- EPA's RBLC
- Technical documents and EPA fact sheets, EPA Air Pollution Control Cost Manual
- NSPS, NESHAP, and MACT regulations
- Utah State Rules
- SJVAPCD Current Rules and BACT Clearinghouse
- SCAQMD Current Rules
- BAAQMD Current Rules

The sections below provide a summary of each the control options found in each of the resources listed above.

5A.3.1 $PM_{2.5}$

$PM_{2.5}$ emissions are generated from the combustion of natural gas and from the drying/heating process.

RBLC and Technical Documents

The following control technologies were identified as available options for $PM_{2.5}$ emissions from drying ovens.

- Good combustion practices to ensure complete combustion
- Use of gaseous fuels
- Baghouse
- Cyclone

- Wet Scrubber
- Dry or Wet Electrostatic Precipitator

NSPS, NESHAP, or MACT Regulations
There are numerous NSPS, NESHAP, and MACT rules that apply to ovens for different types of industries. The rules most applicable to the types of ovens/dryers evaluated are:

40 CFR Part 60 Subpart UUU (Standards of Performance for Calciners and Dryers in Mineral Industries) limits total PM emissions to 0.092 g/dsm for calciners and 0.057 g/dscm for calciners and dryers installed in series. The rule limits visible emissions to 10% opacity.

40 CFR Part 63 Subpart QQQ (National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting) limits total PM emissions from copper concentrate dryers to 50 mg/dscm for existing units and 23 mg/dscm for new units.

Utah State Rules
There are no Utah State rules that specifically apply to $PM_{2.5}$ emissions from ovens.

Other State Rules
There are no $PM_{2.5}$ limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5A.3.2 $\underline{NO_X}$

NO_X emissions in ovens/dryers result from natural gas combustion. NO_X occurs primarily through the thermal NO_X mechanism. The thermal NO_X mechanism consists of the thermal dissociation and subsequent reaction of N_2 and O_2 molecules in the combustion air. Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel (USEPA, 1998).

RBLC and Technical Documents
The following control technologies were identified as available options for NO_X emissions from dryers/ovens.

- Good combustion practices to ensure complete combustion
- Pre-combustion modifications (oven fire air, low excess air, air staging, etc)
- Combustion controls
- FGR
- Low NO_X burners
- Ultra-low NO_X burners
- SCR
- SNCR

NSPS, NESHAP, or MACT Regulations
There are no NSPS, NESHAP, or MACT regulations applicable to NO_X emissions from ovens/dryers.

Utah State Rules
UAC R307-401-4 states that owners/operators shall install low oxides of nitrogen burners or equivalent oxides of nitrogen controls whenever existing fuel combustion burners are replaced. However, this rule does not specify NO_X levels that are considered “low oxides of nitrogen”.

Other State Rules
SJVAPCD BACT database lists the use of natural gas as BACT for dryers and ovens. The database lists low NO_X burners rated as low as 9 ppm.

SJVAPCD Rule 4309 for dryers, dehydrators, and ovens applies to units that burn gaseous or liquid fuels and have an input rating of more than 5 MMBtu/hr. This rule limits NO_X concentrations to 4.3 ppmv in natural gas-fired ovens.

SCAQMD Rule 1147 (NO_X Reductions from Miscellaneous Sources) limits the NO_X emissions from ovens and dryers to 30 ppm.

There are no BAAQMD rules applicable to this category.

5A.3.3 SO_2
Sulfur dioxide emissions are a result of sulfur present in fuel combusted in the dryers/ovens. SO_2 emissions from ovens and dryers are anticipated to be relatively minor.

RBLC and Technical Documents
The following control technologies were identified as available options for SO_2 emissions from dryers/ovens.

- Good combustion practices
- Use of low sulfur fuels
- Wet Scrubbers

NSPS, NESHAP, or MACT Regulations
There are no NSPS, NESHAP, or MACT regulations applicable to SO_2 emissions from ovens and dryers.

Utah State Rules
There are no Utah State Rules applicable to SO_2 emissions from ovens and dryers.

Other State Rules
There are no SO_2 limits in the rules of air quality districts in other states (SJVAPCD, SCAQMD, or BAAQMD).

5A.3.4 VOC
VOC emissions in ovens/dryers occur from combustion and drying processes. VOC emissions from combustion are generated when there is insufficient time at high temperature to complete the final step in hydrocarbon oxidation (USEPA, 1998). The combustion of natural gas in the ovens will result in minor VOC emissions. VOC emissions also occur as coatings and other chemicals are volatilized from the drying/heating process.

RBLC and Technical Documents
The following control technologies were identified as available options for VOC emissions from ovens/dryers.

- Good combustion practices to ensure complete combustion
- Carbon Adsorption
- Thermal Oxidizers
- Catalytic Oxidizers

NSPS/NESHAP, or MACT
There are no NSPS, NESHAP, or MACT regulations applicable to VOC emissions from ovens and dryers evaluated in this BACT analysis.

Utah State Rules
There are no Utah State Rule applicable to VOC emissions ovens/dryers.

Other State Rules
There are no VOC limits in the rules of air quality districts in other states (SJVAPCD, SCAQMD, or BAAQMD).

5A.3.5 Ammonia

Ammonia emissions from combustion of natural gas are likely minimal. Ammonia emissions from combustion are more likely to result from ammonia slip in SCR or SNCR units, rather than from the combustion process.

A 1994 EPA document evaluated available ammonia emission factors for ammonia and found that the NAPAP was the only inventory available at the time to include ammonia emission factors for combustion sources. The recommended emission factors for combustion source are 0.49 $lb/10^6\ ft^3$ for natural gas combustion in commercial boilers (Battye, Battye, Overcash, & Fudge, 1994).

Due to the lack of available data and the assumed minimal ammonia emissions from the combustion process, BACT was not evaluated for this pollutant.

5A.4 - Technological Feasibility:

6A.4.1 $PM_{2.5}$

Using natural gas as the primary fuel combined with good combustion practices are technically feasible options to control $PM_{2.5}$ emissions from combustion.

The technical feasibility of add-on controls, such as baghouses, cyclones, scrubbers, and ESPs, depends on the industry and the types of materials being dried/heated in the ovens. Below are possible considerations and limitations of each identified technology:

- Baghouse – high collection efficiency (99-99.99%); may not be efficient for streams with high moisture contents (USEPA, 2003d).
- Cyclone – not effective control for $PM_{2.5}$ emissions, used primarily to control particulates greater than PM_{10}. May be used in conjunction with a baghouse to reduce particulate inlet

loading into the baghouse. PM control efficiencies range between 40% and 90%, depending on particle size (USEPA, 2003b).

- Wet scrubber – generally not used for fine particles. PM control efficiency ranges between 70% and 99%, depending on the application (USEPA, 2003f).
- Wet electrostatic precipitator – effective for materials with high electrical resistivity, such as metals. More commonly used for wet, sticky, flammable, or explosive materials. PM control efficiency ranges between 99% and 99.9%. Safety considerations due to high voltage in the system (USEPA, 2003g).
- Dry electrostatic precipitator – effective for materials with high electrical resistivity, such as metals. PM control efficiency ranges between 99 and 99.9%. Safety considerations due to high voltage in the system (USEPA, 2003c).

5A.4.2 NO_X

Good combustion practices, FGR, low NO_X burners, and ultra-low NO_X burners are technically feasible options for burners in ovens/dryers. Ultra-low burners (9 ppm) are generally not technically feasible for burners rated at less than 2 MMBtu/hr.

The technical feasibility of retrofitting burners with low NO_X burners and ultra-low NO_X burners is dependent on the oven design and mechanical construction of the burners.

Although FGR is technically feasible, it is not recommended as a retrofit option for existing units on its own because it can drastically impact the fuel to air ratio control and combustion efficiency of the burner. Furthermore, the burners in many existing units do not have the proper mechanical construction to accommodate FGR. Typically, FGR is one of the main reduction methods for low-NO_X or ultra-low NO_X burners (Hansen & Hanson, 2017). Therefore, FGR is only considered a technically feasible option when used in conjunction with low-NO_X or ultra-low NO_X burners, and FGR will not be evaluated as a separate control in this BACT analysis.

Pre-combustion modifications are technically feasible, but will often result in minimal emission reductions. Additionally, these modifications will reduce burner efficiency and increase fuel demand, which can consequentially negate emissions reductions obtained by the modification (Hansen & Hanson, 2017). Therefore, these modifications will not be further considered as control options.

Combustion controls consist of burner combustion controls to improve the fuel to air ratio and the combustion efficiency of the burner, which reduces the fuel consumption of the burner (Hansen & Hanson, 2017). NO_X emissions will be reduced as a consequence of reducing the fuel consumption. However, the NO_X concentration of the exhaust will remain the same. For instance, if a burner has a NO_X rating of 60 ppm, combustion controls will reduce how much fuel the burner consumes but the burner rating will remain at 60 ppm. Even though the actual output emissions would decrease from combustion controls, this decrease cannot be effectively quantified for permitting purposes. Therefore, combustion controls will not be further evaluated as part of this BACT analysis despite being technically feasible.

SCR and SNCR are commonly applied to large combustion units (>100 MMBtu/hr). These technologies are more effective controls for exhaust streams with higher NO_X concentrations and high temperatures. Therefore, these control technologies are not considered technically feasible for the small burners typically used for ovens/dryers.

5A.4.3 SO_2

Good combustion practices and use of low sulfur fuels are both technically feasible options for these applications.

Wet scrubbers are typically used to control SO_2 emissions from electrical utilities and industrial sources generating streams with high SO_2 contents, such as coal-fired power plants (USEPA, 2003f). The SO_2 concentrations from burners in ovens/dryers are too low for scrubbers to be technically feasible.

5A.4.4 VOC

Good combustion practices are technically feasible options for these applications.

Post-combustion controls, such as adsorption, thermal incinerators, and catalytic oxidizers, are not technically effective to control VOC emissions from combustion due to the low VOC concentrations from burners in ovens/dryers. However, these technologies may be technically feasible to control VOC emissions from the heating/drying process. The technical feasibility of add-on controls depends on the industry and the types of materials being dried/heated in the ovens. Below are possible considerations and limitations of each identified technology:

- Carbon adsorption – Carbon must be routinely replaced and cleaned to ensure continuous removal efficiency. Routine sampling may be required to monitor carbon breakthrough.
- Catalytic oxidation – Requires high temperature exhaust (600°F – 800°F), additional fuel may be required to heat exhaust. Particulate matter must be removed in order to not foul the system. Efficiency depends on exhaust temperatures and composition (Davis, 2000). More suitable for low exhaust volumes with little variation in VOC content (USEPA, 2003a).
- Thermal oxidation - High operating temperature requirements (600°F – 800°F), additional fuel may be required to heat gas stream to meet operating temperatures (USEPA, 2003e).

5A.4.5 Ammonia

Ammonia emissions from ovens/dryers are assumed to be minimal and there are no known control technologies. Ammonia is therefore not evaluated further.

5A.5 - Ranking of Individual and Combined Controls:

5A.5.1 $PM_{2.5}$

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective.

The identified technologies for natural gas combustion were ranked as follows:

1. Use of gaseous fuels combined with good combustion practices
2. Good combustion practices

The identified technologies for drying/heating emissions were not ranked since the technical feasibility of each control depends on the industry and the types of materials being dried/heated in the ovens.

5A.5.2 NO_X

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1. Ultra-low NO_X burner (<9 ppm) combined with good combustion practices
2. Low NO_X burners (<30 ppm) combined with good combustion practices
3. Good combustion practices

5A.5.3 SO_2

Good combustion practices combined with the use of low sulfur fuels are the only technically feasible controls for dryers/ovens.

5A.5.4 VOC

Good combustion practices is the only technically feasible control for dryers/ovens.

The identified technologies for drying/heating emissions were not ranked since the technical feasibility of each control depends on the industry and the types of materials being dried/heated in the ovens.

5A.5.5 Ammonia

No control options were identified for ammonia emissions from natural gas combustion.

5A.6 - Economic Feasibility:

The only potential controls for the combustion process are associated with reducing NO_X emissions and include ultra-low NO_X burners, low NO_X burners, and good combustion practices. The cost effectiveness of burner replacements and retrofits for existing dryers/ovens are directly related to the size of the burner as well as the remaining life of the burner. Furthermore, retrofitting burners with low NO_X burners and ultra-low NO_X burners may not be a technical feasible option depending on the oven design and mechanical construction of the burners. The size of the dryers/ovens in operation at major sources in the $PM_{2.5}$ nonattainment area range significantly, from approximately 2 MMBtu/hr to 50 MMBty/hr. Many of these ovens/dryers are already equipped with ultra-low NO_X burners or low NO_X burners. Due to the variability in size, design, and process type, an economic analysis of replacing or retrofitting burners in ovens/dryers could not be conducted.

The technical feasibility of the controls for drying/heating emissions depends on the industry and the types of materials being dried/heated in the ovens. This BACT analysis is intended to be a general evaluation of the control options available for each emission source and is not an evaluation of the specific emission units in operation. Therefore, an economic feasibility evaluation was not prepared for this BACT analysis.

5A.7 - Evaluation of Findings & Control Selection:

DAQ recommends that BACT for combustion emissions is good combustion practices. An evaluation to determine whether retrofitting or replacing a burner with low-NO_X or ultra-low NO_X options is economically feasible should be conducted on a case-by-case basis.

BACT for drying/heating emissions shall also be determined on a case-by-case basis. Due to the variability in processes and types of materials being dried/heated in the ovens, a BACT recommendation cannot be specified as part of this analysis.

5A.8 - Time for Implementation:

Good combustion practices shall be implemented immediately. Owners/operators shall evaluate the technical and economic feasibility of replacing or retrofitting burners in ovens/dryers. If this evaluation shows that it is economically feasible to upgrade or replace burners, construction and installation shall be completed within one year.

5B. - Natural Gas-Fired Boilers Rated between 30 MMBtu/hr and 10 MMBtu/hr

5B.1 - Description:

Boilers (or process heaters) are used in a variety of industrial and commercial applications to produce steam or hot water. Examples of sources that operate boilers and process heaters include oil and gas sources, petroleum refineries, manufacturing plants, agricultural, and food processing plants, and commercial industries.

Boilers are designed in many different configurations and sizes depending on the fuel, required heat output, and emission controls. In general, boilers convert chemical energy in fuel into thermal energy. Boilers have combustion chambers, where the fuel is mixed with oxygen. Burners introduce fuel and air into the combustion chamber at the required velocity, turbulence, and concentration (Oland, 2002).

Boilers can be fueled using a variety of fuel types, such as natural gas, fuel oil, propane, biomass, or coal. Natural gas is the most common type of fuel for boilers. This BACT analysis was performed for boilers fueled by natural gas and dual fuel boilers (e.g. natural gas as the primary fuel and diesel or fuel oil as the backup fuel) with input ratings greater than 10 MMBtu/hr and less than or equal to 30 MMBtu/hr.

5B.2 - Emissions Summary:

The primary pollutants from the combustion of natural gas and fuel oil in the boilers are NO_X and CO. Particulates, SO_2, VOC, and HAP are emitted at lower levels. Emissions are summarized in the table below for each fuel type.

Table 1. Representative Boiler Emission Estimates

Pollutant	Emissions by Fuel Type (tpy)[1]	
	Fuel Oil[2,3,4]	Natural Gas[5,6]
NO_X	0.21	12.88
CO	0.05	10.82
PM_{10}	0.04	0.98
$PM_{2.5}$	0.04	0.98
SO_2	2.28E-03	0.08
VOC	3.64E-03	0.71
HAP	4.39E-04	0.24

Notes:
[1]Boiler size 30 MMBtu/hr
[2]Conversion factor of 140,000 Btu/gal (AP-42)
[3]Emission factors in AP-42, Chapter 1.3 used.
[4] Fuel oil boilers assumed to operate 100 hours per year (or approximately 2 hours per week).
[5] Natural gas boilers assumed to operate 8,760 hours per year.
[6]Uncontrolled emission factors in AP-42, Chapter 1.4 used.

5B.3 - Control Options:

This BACT analysis was performed for control options for $PM_{2.5}$ and $PM_{2.5}$ precursors (NO_X, SO_2, VOC, and ammonia). The following sources were evaluated to identify control options for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr:

- EPA's RBLC
- Technical documents, EPA fact sheets, and other applicable literature
- NSPS, NESHAP, and MACT regulations
- Utah State Rules
- SJVAPCD Current Rules and BACT Clearinghouse
- SCAQMD Current Rules
- BAAQMD Current Rules

The sections below provide a summary of each of the control options found in the resources listed above. Available control options are described for each pollutant evaluated.

5B.3.1 $PM_{2.5}$

$PM_{2.5}$ emissions are generated when solid material is released during combustion. PM emissions are often released as ash-forming matter or carbon particles and are more prevalent as a result of combustion of solid fuels (Oland, 2002). This BACT analysis only evaluates natural gas and diesel fuel combustion, so $PM_{2.5}$ emissions are anticipated to be relatively minor.

RBLC and Technical Documents

The following control technologies were identified as available options for $PM_{2.5}$ emissions from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

- Good combustion practices
- Use of gaseous fuels
- Baghouses
- Cyclone
- Wet Scrubber
- Electrostatic Precipitators

NSPS, NESHAP, or MACT Regulations

40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) applies to each new steam generating unit that has a maximum design heat input capacity greater than or equal to 10 MMBtu/hr and less than 100 MMBtu/hr. The applicability date for NSPS Subpart Dc is June 9, 1989. Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. The Subpart has requirements for PM emissions for boilers burning solid fuels (coal and wood) and for oil-burning boilers with input heating capacities greater than 30 MMBtu/hr.

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) applies to industrial, commercial, or institutional boilers located at an area source of HAP emissions. This rule applies to boilers that burn solid fuel or liquid fuel. Gas-fired boilers are defined in 40 CFR 63.11237 as a boiler that only burns gaseous fuels during normal operation and burns liquid fuel only during periods of

gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. 40 CFR 63.11195 exempts gas-fired boilers from the applicability and requirements of MACT Subpart JJJJJJ as long as the boilers only burn liquid fuel during periods of gas curtailment, gas supply interruption and periodic testing, maintenance, or operator training up to 48 hours per year. Oil-fired boilers that exceed the 48-hour per year limit are subject to a PM limit of 0.3 lb/MMBtu of heat input (filterable PM) (Table 1 to Subpart JJJJJJ). Boilers that burn ultra-low sulfur liquid fuel are not subject to this PM emission limit, provided that appropriate monitoring is conducted and recorded [63.11210(e)].

Utah State Rules
There are no Utah State rules applicable to $PM_{2.5}$ emissions from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

Other State Rules
There are no $PM_{2.5}$ limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5B.3.2 NO_X

NO_X emissions from combustion processes occur primarily through the thermal NO_X mechanism. The thermal NO_X mechanism consists of the thermal dissociation and subsequent reaction of N_2 and O_2 molecules in the combustion air. Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel (USEPA, 1998).

RBLC and Technical Documents
The following control technologies were identified as available options for NO_X emissions from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

- Good combustion practices
- Pre-combustion modifications (oven fire air, low excess air, air staging, etc)
- Combustion Controls
- FGR
- Low NO_X burners
- Ultra-low NO_X burners
- SCR
- SNCR

NSPS, NESHAP, or MACT Regulations
40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) does not specify NO_X emission limits or controls for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr under this Subpart.

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) does not specify NO_X emission limits or controls for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr under this Subpart.

Utah State Rules

UAC R307-401-4 states that owners/operators shall install low oxides of nitrogen burners or equivalent oxides of nitrogen controls whenever existing fuel combustion burners are replaced. However, this rule does not specify NO_X levels that are considered “low oxides of nitrogen”.

Other State Rules

The SJVAPCD BACT clearinghouse does not list any current BACT determinations for commercial boilers.

Tables 2 through 4 below summarize the NO_X limits identified in the BAAQM, SJVAPCD, SCAQMD rules, respectively. The lowest NOx limits identified in the summarized rules is 9 ppm. However, SCAQMD has established BACT limits as low as 7 ppmv for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr. These units were equipped with SCR to achieve the 7 ppmv limit.

5B.3.3 $\underline{SO_2}$

Sulfur dioxide emissions are a result of sulfur present in fuel combusted in the boilers. SO_2 emissions from boilers are anticipated to be relatively minor.

RBLC and Technical Documents

The following control technologies were identified as available options for SO_2 emissions from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

- Good combustion practices
- Use of low sulfur fuels
- Wet Scrubbers

NSPS, NESHAP, or MACT Regulations

40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) specifies that boilers between 10 and 30 MMBtu/hr that combust oil are required to limit emissions to less than 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, the boilers cannot combust oil that contains greater than 0.5 weight percent sulfur [60.42c(d)].

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) specifies that boilers that burn primarily diesel or fuel oil are subject to this rule. Oil-fired boilers are not subject to a specific SO_2 limitation under this rule, however, boilers that burn ultra-low sulfur liquid fuel are not subject to the PM emission limit, provided that appropriate monitoring is conducted and recorded [63.11210(e)].

Utah State Rules

There are no Utah State Rules applicable to SO_2 emissions from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

Other State Rules

There are no SO_2 limits in the rules of air quality districts in other states (SJVAPCD, SCAQMD, or BAAQMD).

5B.3.4 VOC

VOC emissions from combustion occur due to incomplete combustion. VOC emissions are generated when there is insufficient time at high temperature to complete the final step in hydrocarbon oxidation. The combustion of natural gas and diesel in boilers will result in minor VOC emissions (USEPA, 1998).

RBLC and Technical Documents

The following control technologies were identified as available options for VOC emissions from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

- Good combustion practices
- Carbon Adsorption
- Thermal Oxidizers
- Catalytic Oxidizers

NSPS/NESHAP, or MACT

40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) does not specify VOC emission limits for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr under this Subpart.

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) does not specify VOC emission limits for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr under this Subpart.

Utah State Rules

There are no Utah State Rules applicable to VOC emissions from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

Other State Rules

There are no VOC limits in the rules of air quality districts in other states (SJVAPCD, SCAQMD, or BAAQMD).

5B.3.5 Ammonia

Ammonia emissions from the combustion of natural gas and diesel fuel are anticipated to be minimal. Ammonia emissions from combustion are more likely to result from ammonia slip in SCR or SNCR units, rather than from the combustion process.

A 1994 EPA document evaluated available ammonia emission factors for ammonia and found that the NAPAP was the only inventory available at the time to include ammonia emission factors for combustion sources. The recommended emission factors for combustion sources are 0.49 lb/10^6 ft^3 for natural gas combustion in commercial boilers and 0.8 lb/1,000 gal for fuel oil combustion (Battye, Battye, Overcash, & Fudge, 1994).

There are no known control technologies to control ammonia emissions from boilers.

Due to the lack of available data and the anticipated minimal ammonia emissions from combustion processes, BACT was not evaluated for this pollutant.

5B.4 - Technological Feasibility:

5B.4.1 $PM_{2.5}$

Use of gaseous fluids and good combustion practices are technically feasible options to control $PM_{2.5}$ emissions from combustion.

Post-combustion technologies, such as baghouses, cyclones, and scrubbers, have not been demonstrated as technically feasible options for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

5B.4.2 NO_X

Good combustion practices, combustion controls, FGR, low NO_X burners, and ultra-low NO_X burners are technically feasible options for burners in boilers. The lowest NO_X emission levels that can be technically achieved in boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr is 9 ppm. As shown in Table 4, Rule 4306 of SJAQMD includes an enhanced limit of 6 ppm for boilers with input ratings greater than or equal to 20 MMBtu/hr; however, this rating is not widely available. The enhanced option of this rule required lower NO_X limits but allowed more time for compliance.

Although FGR is technically feasible, it is not recommended as a retrofit option for existing boilers on its own because it can drastically impact the fuel to air ratio control and combustion efficiency of the burner. Furthermore, the burners in many existing boilers do not have the proper mechanical construction to accommodate FGR. Typically, FGR is one of the main reduction methods for low-NO_X or ultra-low NO_X burners (Hansen & Hanson, 2017). Therefore, FGR is only considered a technically feasible option when used in conjunction with low- NO_X or ultra-low NO_X burners and will not be evaluated as a separate control in this BACT analysis.

Pre-combustion modifications are technically feasible, but will often result in minimal emission reductions. Additionally, these modifications will reduce burner efficiency and increase fuel demand, which can consequentially negate emissions reductions obtained by the modification (Hansen & Hanson, 2017). Therefore, these modifications will not be further considered as control options.

Combustion controls improve the fuel to air ratio and the combustion efficiency of the burner, which reduces the fuel consumption of the burner (Hansen & Hanson, 2017). NO_X emissions will be reduced as a consequence of reducing the fuel consumption. However, the NO_X concentration of the exhaust will remain the same. For instance, if a boiler operates a burner with a NO_X rating of 60 ppm, combustion controls will reduce how much fuel the burner consumes but the burner rating will remain at 60 ppm. Combustion controls will reduce actual emissions through fuel consumption; however, this decrease cannot be effectively quantified for permitting purposes. Therefore, combustion controls will not be further evaluated as part of this BACT analysis despite being technically feasible.

SCR is an add-on technology that chemically reduces NO_X compounds from the stack flue gas to N_2 and water. Ammonia is injected into the flue gas upstream of the catalyst chamber. The ammonia-air mixture then passes through a thermal catalytic reactor where the catalytic reaction is completed. NO_X reduction in SCR is only effective at high temperatures (480°F to 800°F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SCR NO_X removal efficiencies are between 70% and 90% (Oland, 2002).

SNCR is similar to SCR in the use of ammonia as a reductant to reduce NO_X compounds to molecular N_2 and water but the technology does not utilize a catalyst. The ammonia is injected directly into the primary combustion zone where temperatures reach 1,400 to 2,000°F. NO_X reduction in SNCR is only effective at high temperatures (1600°F to 2100°F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SCNR NO_X removal efficiencies vary between 30% and 70% (Oland, 2002).

Although these technologies are technically feasible for controlling NOx emissions from boilers, there are several additional considerations that may make these controls technically infeasible:

- Due to the costs of SCR and SNCR systems, these technologies are usually applied to large combustion units (>100 MMBtu/hr) (CleaverBrooks, 2010).
- High operating temperature requirements may require additional heating of the exhaust stream.
- Space constraints of existing operations may prohibit the installation of SCR or SNCR systems.
- Health and safety considerations since SCR and SNCR require storage and handling of ammonia, a hazardous chemical.
- Ammonia slip (i.e ammonia emissions from unreacted ammonia) pose additional environmental and safety concerns (Oland, 2002).

Despite the above-mentioned considerations, DAQ found some examples of SCR systems installed in boilers between 16 MMBtu/hr and 30 MMBtu/hr. The BACT limit for these boilers is 7 ppmv. Therefore, DAQ will continue to evaluate SCR as a potential control option.

5B.4.3 SO_2

Good combustion practices and use of low sulfur fuels are both technically feasible options for boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

Wet scrubbers are typically used to control SO_2 emissions from electrical utilities and industrial sources generating streams with high SO_2 contents, such as coal-fired power plants (USEPA, 2003). The SO_2 concentrations from natural gas or diesel-fired burners in boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr are too low for scrubbers to be technically feasible.

5B.4.4 VOC

Good combustion practices are technically feasible options for these applications.

Post-combustion controls, such as adsorption, thermal incinerators, and catalytic oxidizers, have not been demonstrated to be technically effective to control VOC emissions from combustion due to the low VOC concentrations from boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

5B.4.5 Ammonia

Ammonia emissions from boilers are assumed to be minimal and there are no known control technologies.

5B.5 - Ranking of Individual and Combined Controls:

5B.5.1 $PM_{2.5}$

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1. Use of gaseous fuels combined with good combustion practices
2. Good combustion practices

5B.5.2 NO_X

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1. SCR (7 ppm)
2. Ultra-low NO_X burners (<9 ppm) and good combustion practices
3. Low NO_X burners (<30 ppm) and good combustion practices
4. Good combustion practices

5B.5.3 SO_2

Good combustion practices combined with the use of low sulfur fuels is the only technically feasible control for natural gas and diesel-fired boilers with input ratings greater than 10 MMBtu/hr and less than or equal to 30 MMBtu/hr.

5B.5.4 VOC

Good combustion practices is the only technically feasible control for natural gas and diesel-fired boilers with input ratings greater than 10 MMBtu/hr and less than or equal 30 MMBtu/hr.

5B.5.5 Ammonia

No control options were identified for ammonia emissions from natural gas and diesel-fired boilers with input ratings greater than 10 MMBtu/hr and less than or equal to 30 MMBtu/hr.

5B.6 - Economic Feasibility:

DAQ evaluated the cost of retrofitting uncontrolled boilers with low NO_X (30 ppm) and ultra-low NO_X burners (9 ppm) as well as replacing uncontrolled boilers with low NO_X and ultra-low NO_X alternatives. Costs were obtained for boilers with input ratings of 30, 20, and 15 MMBtu/hr. Boilers with input ratings less than 10 MMBtu/hr are evaluated in Section 5C of this document.

One important consideration when evaluating the cost effectiveness of retrofitting boilers with low NO_X and ultra-low NO_X burners is the age of the boilers. Typically, boilers have a service life of 20-40 years; the average age of the boilers installed at major sources in the $PM_{2.5}$

nonattainment area is 26 years. Retrofit costs were evaluated for boilers with 30, 20, and 10 years of in-service life remaining.

Another important consideration is the usage of the boiler. The hours of operation for the existing boilers at major sources within the $PM_{2.5}$ nonattainment area varies significantly, depending on source operations and heating requirements. In order to account for this variation, DAQ evaluated two operational scenarios. The first scenario is for continuous boiler operation (8,760 hours per year). The second scenario is for periodic boiler operation (4,000 hours per year). The second scenario accounts for constant operation during cold weather (November through March) and some additional hours of operation during warm weather.

Table 5 shows a summary of the costs of the retrofit and replacement options for 8,760 hours of operation per year. Table 6 shows a summary of the costs of the retrofit and replacement options for 4,000 hours of operation per year. Detailed cost estimates are provided in Attachment A.

The cost per ton of NO_X removed for low NO_X burner retrofits of boilers range between $4,884 for a 30 MMBtu/hr boiler to $9,061 for a 15 MMBtu/hr boiler for 8,760 hours of operation per year and $10,697 for a 30 MMBtu/hr boiler to $19,845 for a 15 MMBtu/hr boiler for 4,000 hours of operation per year.

The cost per ton of NO_X removed for ultra-low NO_X burner retrofits of boilers range between $4,135 for a 30 MMBtu/hr boiler to $7,006 for a 15 MMBtu/hr boiler for 8,760 hours of operation per year and $9,055 for a 30 MMBtu/hr boiler to $15,344 for a 15 MMBtu/hr boiler for 4,000 hours of operation per year.

The cost per ton of NO_X removed for low NO_X boiler replacement ranges between $9,447 for a 30 MMBtu/hr boiler to $13,938 for a 15 MMBtu/hr boiler for 8,760 hours of operation per year and $20,687 for a 30 MMBtu/hr boiler to $30,524 for a 15 MMBtu/hr boiler for 4,000 hours of operation per year.

The cost per ton of NO_X removed for ultra-low NO_X boiler replacement ranges between $8,649 for a 30 MMBtu/hr boiler to $11,001 for a 15 MMBtu/hr boiler for 8,760 hours of operation per year and $18,941 for a 30 MMBtu/hr boiler to $24,091 for a 15 MMBtu/hr boiler for 4,000 hours of operation per year.

Many of the boilers rated between 10 MMBtu/hr and 30 MMBtu/hr currently in operation at major sources in the $PM_{2.5}$ nonattainment area are low NO_X or ultra-low NO_X boilers. DAQ evaluated the cost of upgrading existing low- NO_X boilers by either retrofitting the boilers with ultra-low NO_X burners or replacing these boilers with ultra-low NO_X boilers.

The cost per ton of NO_X removed for low NO_X burner retrofits of boilers range between $14,097 for a 30 MMBtu/hr boiler to $23,889 for a 15 MMBtu/hr boiler for 8,760 hours of operation per year and $30,874 for a 30 MMBtu/hr boiler to $52,316 for a 15 MMBtu/hr boiler for 4,000 hours of operation per year.

The cost per ton of NO_X removed for ultra-low NO_X boiler replacement range between $29,489 for a 30 MMBtu/hr boiler to $37,508 for a 15 MMBtu/hr boiler for 8,760 hours of operation per year and $64,581 for a 30 MMBtu/hr boiler to $82,142 for a 15 MMBtu/hr boiler for 4,000 hours of operation per year.

DAQ also evaluated the cost of retrofitting existing uncontrolled boilers with SCR, as summarized in Table 5. The cost per ton of NOx removed for SCR retrofit range between $19,775 for a 30 MMBtu/hr boiler to $25,380.57 for a 15 MMBtu/hr boiler. These costs are based on continuous operation (8,760 hours/year) and an equipment life of 25 years. These costs do not account for retrofitting an existing boiler to accommodate SCR. The mechanical configuration and operating parameters of each individual boiler may require modifications to ductwork, dampers, and control systems, which will increase the capital and operating costs of an SCR system (USEPA, 2002).

5B.7 - <u>Evaluation of Findings & Control Selection:</u>

The economic feasibility analysis demonstrates that retrofit options and boiler replacement could both be cost effective options depending on the boiler size, age, and hours of operation. DAQ found through this analysis that SCR was not a cost-effective feasible option.

As shown in Tables 5 and 6, the cost per ton of NO_X removed for retrofitting a burner starts at $4,135 and the cost per ton of NO_X removed range starts at $8,649. Depending on the hours of operation, replacing or retrofitting uncontrolled boilers with low NO_X options would reduce emissions by 3.69 to 8.1 tpy for a 30 MMBtu/hr boiler and from 1.85 to 4.0 tpy for a 15 MMBtu/hr. Replacing or retrofitting uncontrolled boilers with ultra-low NO_X options would reduce emissions by 5.23 to 11.4 tpy for a 30 MMBtu/hr boiler and 2.61 to 5.7 tpy for a 15 MMBtu/hr.

Retrofitting or replacing existing low-NO_X boilers with ultra-low NO_X boilers proved to be cost prohibitive for the scenarios evaluated. Retrofit costs start at $14,097 per ton of NO_X removed and replacement costs start at $29,489. Emission reductions under this scenario range between 3.36 tpy for a 30 MMBtu/hr boiler to 1.68 tpy for a 15 MMBtu/hr.

DAQ recommends good combustion practices as BACT for the existing boilers operating at major sources within the nonattainment area. An evaluation to determine whether retrofitting or replacing boilers with low-NO_X or ultra-low NO_X burners is economically feasible should be conducted on a case-by-case basis.

Diesel or fuel oil may only be used as backup fuel. The sulfur content of any diesel or fuel oil burned shall not exceed 15 ppm by weight.

5B.8 - <u>Time for Implementation:</u>

Owners/operators have 30 days from the date of this document to comply with the BACT determination of good combustion practices, use of natural gas as a primary fuel, and the use of diesel fuel not exceeding 15 ppm by weight as backup fuel or as primary fuel in areas where natural gas is not available.

Owners/operators shall evaluate the economic feasibility of retrofitting or replacing boilers with low-NO_X or ultra-low NO_X burners. If this evaluation shows that it is economically feasible to retrofit or replace boilers, construction and installation shall be completed within one year of the date of this document.

6B.9 - <u>Supporting Tables:</u>

Table 2. Summary of BAAQMD NO_X Limits

Rule	Applicability Thresholds	Fuel	NO_X Limit	Applicability Dates
Regulation 9, Rule 7 - Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	10 to <20 MMBtu/hr	Natural Gas	15 ppmv	Applicable to all boilers at a source (new and existing). Existing boilers must meet applicable emission limits within two years of effective date (January 1, 2013 for boilers <10 MMBtu/hr and January 1, 2012 for boilers >=10 MmBtu/hr)
	20 to <75 MMBtu/hr	Natural Gas	9 ppmv	

Table 3. Summary of SCAQMD NO_X Limits

Rule	Applicability Thresholds	Fuel	NO_X Limit	Applicability Dates
Rule 1146 - Emissions of oxides of nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	5 to <20 MMBtu/hr	Natural Gas	9 ppmv or 0.011 lbs/MMBtu	All units at a source must show compliance on or before January 1, 2015.
	20 to <75 MMBtu/hr	Natural Gas	9 ppmv or 0.011 lbs/MMBtu	All units at a source must show compliance on or before January 1, 2014.
	All Units fired on non-gaseous fuels	Non-gaseous fuels	40 ppm	All units at a source must show compliance on or before January 1, 2008.

Table 4. Summary of SJAQMD NO_X Limits

Rule	Applicability Thresholds	Fuel	NO_X Limit	Applicability Dates
Rule 4306 - Boilers Steam Generators, and Process Heaters - Phase 3	5 to <20 MMBtu/hr	Natural Gas	Standard Option: 15 ppmv or 0.018 lb/MMBtu Enhanced Option: 9 ppmv or 0.011 lb/MMBtu	All units at a source must show compliance on or before December 1, 2008.
	5 to <20 MMBtu/hr	Liquid Fuel	40 ppmv or 0.052 lb/MMBtu	
	>=20 MMBtu/hr	Natural Gas	Standard Option: 9 ppmv or 0.011 lb/MMBtu Enhanced Option: 6 ppmv or 0.007 lb/MMBtu	
	Refinery Units 5 to 65 MMBtu/hr	Natural Gas	Standard Option: 30 ppmv or 0.036 lb/MMBtu Enhanced Option: No option	

Table 5. Summary of Cost per Ton of NO_X (\$/ton) Removed
Continuous Operation (8,760 hours/year)

Control Option	Remaining In-Service Life	Boiler Size (MMBtu/hr)		
		30	20	15
Standard to Low NO_X Burner Retrofit[1]	30 years	\$4,884.43	\$6,481.24	\$7,246.13
	20 years	\$5,160.99	\$6,799.28	\$7,651.75
	10 years	\$6,122.16	\$7,904.63	\$9,061.46
Standard to Ultra-Low NO_X Burner Retrofit[1]	30 years	\$4,134.69	\$4,964.44	\$5,519.22
	20 years	\$4,408.31	\$5,233.18	\$5,851.48
	10 years	\$5,359.29	\$6,167.18	\$7,006.24
Low NO_X Boiler Replacement[1]	N/A	\$9,446.94	\$11,728.12	\$13,937.81
Ultra-Low NO_X Boiler Replacement[1]	N/A	\$8,648.81	\$9,397.96	\$11,000.66
Low to Ultra-Low NO_X Burner Retrofit (30 ppm to 9 ppm)[2]	30 years	\$14,097.66	\$16,926.79	\$18,818.38
	20 years	\$15,030.60	\$17,843.08	\$19,951.24
	10 years	\$18,273.06	\$21,027.64	\$23,888.51
Ultra-Low NO_X Boiler Replacement (30 ppm to 9 ppm)[2]	N/A	\$29,489.04	\$32,043.33	\$37,507.91
SCR Retrofits[3]	25 years	\$19,774.94	\$23,265.39	\$25,380.57

Notes:
[1] Costs based on the emission reductions from a standard burner to a low NO_X or ultra-low NO_X burner.
[2] Costs based on the emission reductions from a low NO_X burner to an ultra-low NO_X burner.
[3] Costs do not include retrofitting existing boilers to accommodate SCR.

N/A – Not applicable
Standard burner: 80 ppm
Low NO_X burners: 30 ppm
Ultra-low NO_X burners: 9 ppm

Table 6. Summary of Cost per Ton of NO_X ($/ton) Removed
Periodic Operation (4,000 hours/year)

Control Option	Remaining In-Service Life	Boiler Size (MMBtu/hr) 30	20	15
Standard to Low NO_X Burner Retrofit[1]	30 years	$10,696.90	$14,193.91	$15,869.03
	20 years	$11,302.56	$14,890.42	$16,757.32
	10 years	$13,407.52	$17,311.13	$19,844.60
Standard to Ultra-Low NO_X Burner Retrofit[1]	30 years	$9,054.97	$10,872.13	$12,087.10
	20 years	$9,654.20	$11,460.66	$12,814.74
	10 years	$11,736.84	$13,506.12	$15,343.67
Low NO_X Boiler Replacement[1]	N/A	$20,688.79	$25,684.59	$30,523.80
Ultra-Low NO_X Boiler Replacement[1]	N/A	$18,940.90	$20,581.53	$24,091.45
Low to Ultra-Low NO_X Burner Retrofit (30 ppm to 9 ppm)[2]	30 years	$30,873.87	$37,069.67	$41,212.25
	20 years	$32,917.02	$39,076.34	$43,693.22
	10 years	$40,018.01	$46,050.52	$52,315.85
Ultra-Low NO_X Boiler Replacement (30 ppm to 9 ppm)[2]	N/A	$64,580.99	$70,174.88	$82,142.33

Notes:
[1] Costs based on the emission reductions from a standard burner to a low NO_X or ultra-low NO_X burner.
[2] Costs based on the emission reductions from a low NO_X burner to an ultra-low NO_X burner.

N/A – Not applicable
Standard burner: 80 ppm
Low NO_X burners: 30 ppm
Ultra-low NO_X burners: 9 ppm

5C. - Natural Gas-Fired Boilers Rated less than 10 MMBtu/hr

5C.1 - Description:

Boilers (or process heaters) are used in a variety of industrial and commercial applications to produce steam or hot water. Examples of sources that operate boilers and process heaters include oil and gas sources, petroleum refineries, manufacturing plants, agricultural, and food processing plants, and commercial industries.

Boilers are designed in many different configurations and sizes depending on the fuel, required heat output, and emission controls. In general, boilers convert chemical energy in fuel into thermal energy. Boilers have combustion chambers, where the fuel is mixed with oxygen. Burners introduce fuel and air into the combustion chamber at the required velocity, turbulence, and concentration (Oland, 2002).

Boilers can be fueled using a variety of fuel types, such natural gas, fuel oil, propane, biomass, or coal. Natural gas is the most common type of fuel for boilers. This BACT analysis was performed for boilers fueled by natural gas and dual fuel boilers (e.g. natural gas as primary fuel and diesel or fuel oil as backup fuel) with input ratings less than or equal to 10 MMBtu/hr.

5C.2 - Emissions Summary:

The primary pollutants from the combustion of natural gas and fuel oil in the boilers are NO_X and CO. Particulates, SO_2, VOC, and HAP are emitted at lower levels. Emissions are summarized in the table below for each fuel type.

Table 1. Representative Boiler Emission Estimates

	Emissions by Fuel Type (tpy)1	
Pollutant	Fuel Oil2,3,4	Natural Gas4,5
NO_X	3.13	4.29
CO	0.78	3.61
PM_{10}	0.52	0.33
$PM_{2.5}$	0.52	0.33
SO_2	3.332E-04	0.03
VOC	5.319E-02	0.24
HAP	6.416E-03	0.08

Notes:
1Representative boiler sizes 10 MMBtu/hr for natural gas and 5 MMBtu/hr for fuel oil used
2Conversions factor of 140,000 Btu/gal (AP-42)
3Emission factors in AP-42, Chapter 1.3 used.
4 Boilers assumed to operate 8,760 hours per year.
5Uncontrolled emission factors in AP-42, Chapter 1.4 used.

5C.3 - Control Options:

This BACT analysis was performed for control options for $PM_{2.5}$ and $PM_{2.5}$ precursors (NO_X, SO_2, VOC, and ammonia). The following sources were evaluated to identify control options for boilers with input ratings less than or equal to 10 MMBtu/hr.

- EPA's RBLC
- Technical documents, EPA fact sheets, and other applicable literature
- NSPS, NESHAP, and MACT regulations
- Utah State Rules
- SJVAPCD Current Rules and BACT Clearinghouse
- SCAQMD Current Rules
- BAAQMD Current Rules
- The sections below provide a summary of each the control options found in each of the resources listed above. Available control options are described for each pollutant evaluated.

5C.3.1 $PM_{2.5}$

$PM_{2.5}$ emissions are generated when solid material is released during combustion. PM emissions are often released as ash-forming matter or carbon particles and are more prevalent as a result of combustion of solid fuels (Oland, 2002). This BACT analysis only evaluates natural gas and diesel fuel combustion, so $PM_{2.5}$ emissions are anticipated to be relatively minor.

RBLC and Technical Documents
The following control technologies were identified as available options for $PM_{2.5}$ emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Use of gaseous fuels
- Baghouses
- Cyclone
- Wet Scrubber
- Electrostatic Precipitators

NSPS, NESHAP, or MACT Regulations
There are no NSPS regulations applicable to boilers with input ratings less than or equal to 10 MMBtu/hr.

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) applies to industrial, commercial, or institutional boilers located at an area source of HAP emissions that burn solid fuel or liquid fuel. Dual fuel boilers (e.g. natural gas as primary fuel and diesel or fuel oil as backup fuel) are only subject to this rule if the boilers burn liquid fuel during periods of gas curtailment, gas supply interruption and periodic testing, maintenance, or operator training for more than 48 hours per year (40 CFR 63.11237 and 40 CFR 63.11195). Boilers that burn primarily diesel or fuel oil are subject to this rule. Boilers rated at less than 10 MMBtu are subject to specific maintenance and work practices. There are no limitations on PM emission for boilers with an input heat capacity of less than 10 MMBtu/hr.

Utah State Rules
There are no Utah State rules applicable to $PM_{2.5}$ emissions from boilers rated less than 10 MMBtu/hr.

Other State Rules
There are no $PM_{2.5}$ limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5C.3.2 $\underline{NO_X}$

NO_X emissions from combustion processes occur primarily through the thermal NO_X mechanism. The thermal NO_X mechanism consists of the thermal dissociation and subsequent reaction of N_2 and O_2 molecules in the combustion air. Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel (USEPA, 1998, p. 42).

RBLC and Technical Documents
The following control technologies were identified as available options for NO_X emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Pre-combustion modifications (oven fire air, low excess air, air staging, etc)
- Combustion controls
- FGR
- Low NO_X burners
- Ultra-low NO_X burners
- SCR
- SNCR

NSPS, NESHAP, or MACT Regulations
There are no NSPS regulations applicable to boilers with input ratings less than or equal to 10 MMBtu/hr.

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) does not specify NO_X emission limits or controls for boilers with an input heat capacity of less than 10 MMBtu/hr. Boilers rated at less than 10 MMBtu/hr are subject to specific maintenance and work practices.

Utah State Rules
UAC R307-401-4 states that owners/operators shall install low oxides of nitrogen burners or equivalent oxides of nitrogen controls whenever existing fuel combustion burners are replaced. However, this rule does not specify NO_X levels that are considered “low oxides of nitrogen”.

Other State Rules
The SJVAPCD BACT clearinghouse does not list any current BACT determinations for commercial boilers.

Tables 2 through 4 below summarize the NO_X limits identified in the BAAQM, SJVAPCD, SCAQMD rules, respectively.

5C.3.3 SO_2

Sulfur dioxide emissions are a result of sulfur present in fuel combusted in the boilers. SO_2 emissions from boilers are anticipated to be relatively minor.

RBLC and Technical Documents

The following control technologies were identified as available options for SO_2 emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Use of low sulfur fuels
- Wet Scrubbers

NSPS, NESHAP, or MACT Regulations

There are no NSPS regulations applicable to boilers with input ratings less than or equal to 10 MMBtu/hr.

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) does not specify SO_2 emission limits or controls for boilers with an input heat capacity of less than 10 MMBtu/hr. Boilers rated at less than 10 MMBtu are subject to specific maintenance and work practices.

Utah State Rules

There are no Utah State Rule applicable to SO_2 emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

Other State Rules

There are no SO_2 limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5C.3.4 VOC

VOC emissions from combustion occur due to incomplete combustion. VOC emissions are generated when there is insufficient time at high temperature to complete the final step in hydrocarbon oxidation. The combustion of natural gas and diesel in boilers will result in minor VOC emissions (USEPA, 1998).

RBLC and Technical Documents

The following control technologies were identified as available options for VOC emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Carbon Adsorption
- Thermal Oxidizers
- Catalytic Oxidizers

NSPS/NESHAP, or MACT
There are no NSPS regulations applicable to boilers with input ratings less than or equal to 10 MMBtu/hr.

40 CFR 63 JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) does not specify VOC emission limits or controls for boilers with an input heat capacity of less than 10 MMBtu/hr. Boilers rated at less than 10 MMBtu are subject to specific maintenance and work practices.

Utah State Rules
There are no Utah State Rule applicable to VOC emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

Other State Rules
There are no VOC limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5C.3.5 Ammonia
Ammonia emissions from combustion of natural gas and diesel fuel are anticipated to be minimal. Ammonia emissions from combustion are more likely to result from ammonia slip in SCR or SNCR units, rather than from the combustion process.

A 1994 EPA document evaluated available ammonia emission factors for ammonia and found that the NAPAP is the only inventory available at the time to include ammonia emission factors for combustion sources. The recommended emission factors for combustion source are 0.49 lb/10^6 ft^3 for natural gas combustion in commercial boilers and 0.8 lb/1,000 gal for fuel oil combustion (Battye, Battye, Overcash, & Fudge, 1994).

There are no known control technologies to control ammonia emissions from boilers.

Due to the lack of available data and the anticipated minimal ammonia emissions from combustion processes, BACT was not evaluated for this pollutant.

5C.4 - Technological Feasibility:

5C.4.1 $PM_{2.5}$
Use of gaseous fluids and good combustion practices are technically feasible options to control $PM_{2.5}$ emissions from combustion.

Post-combustion technologies, such as baghouses, cyclones, scrubbers, have not been demonstrated as technically feasible options for boilers rated at less than 10 MMBtu/hr firing gaseous or liquid fuels.

5C.4.2 NO_X
Good combustion practices, combustion controls, FGR, low NO_X burners, and ultra-low NO_X burners are technically feasible options for burners in boilers. The lowest NO_X emission levels

that can be technically achieved in boilers rated between 10 and 3 MMBtu/hr is 9 ppm. Boilers smaller than 3 MMBtu/hr can achieve a NO_X emission level as low as 15 ppm.

NO_X emission levels from other states' air quality rules (BAAQM, SJVAPCD, SCAQMD) evaluated are summarized in Tables 2, 3, and 4. The strictest requirements are 20 ppmv for boilers under 2 MMBtu/hr, 9 ppm for boilers between 2 and 10 MMBtu/hr.

Although FGR is technically feasible, it is not recommended as a retrofit option for existing boilers on its own because it can drastically impact the fuel to air ratio control and combustion efficiency of the burner. Furthermore, the burners in many existing boilers do not have the proper mechanical construction to accommodate FGR. Typically, FGR is one of the main reduction methods for low-NO_X or ultra-low NO_X burners (Hansen & Hanson, 2017). Therefore, FGR is only considered a technically feasible option when used in conjunction with low-NO_X or ultra-low NO_X burners and will not be evaluated as a separate control in this BACT analysis.

Pre-combustion modifications are technically feasible, but will often result in minimal emission reductions. Additionally, these modifications will reduce burner efficiency and increase fuel demand, which can consequentially negate emissions reductions obtained by the modification (Hansen & Hanson, 2017). Therefore, these modifications will not be further considered as control options.

Combustion controls improve the fuel to air ratio and the combustion efficiency of the burner, which reduces the fuel consumption of the burner (Hansen & Hanson, 2017). NO_X emissions will be reduced as a consequence of reducing the fuel consumption. However, the NO_X concentration of the exhaust will remain the same. For instance, if a boiler operates a burner with a NO_X rating of 60 ppm, combustion controls will reduce how much fuel the burner consumes but the burner rating will remain at 60 ppm. Combustion controls will reduce actual emissions through fuel consumption; however, this decrease cannot be effectively quantified for permitting purposes. Therefore, combustion controls will not be further evaluated as part of this BACT analysis despite being technically feasible.

SCR is an add-on technology that chemically reduces NO_X compounds from the stack flue gas to N_2 and water. Ammonia is injected into the flue gas upstream of the catalyst chamber. The ammonia-air mixture then passes through a thermal catalytic reactor where the catalytic reaction is completed. NO_X reduction in SCR is only effective at high temperatures (450°F to 840°F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SCR NO_X removal efficiencies are between 70 to 90% (Oland, 2002).

SNCR is similar to SCR in the use of ammonia as a reductant to reduce NO_X compounds to molecular N_2 and water but the technology does not utilize a catalyst. The ammonia is injected directly into the primary combustion zone where temperatures reach 1,400 to 2,000°F. NO_X reduction in SNCR is only effective at high temperatures (1,400°F to 2,000°F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SCNR NO_X removal efficiencies vary between 30% and 70%. (Oland, 2002).

Although these technologies are technically feasible for controlling NO_X emissions in boilers, they were not further considered for the following reasons:

- Due to the costs of SCR and SNCR systems, these technologies are usually applied to large combustion units (>100 MMBtu/hr) (CleaverBrooks, 2010).
- Ammonia slip from these systems may generate additional ammonia emissions (Oland, 2002).
- High operating temperature requirements may require additional heating of the exhaust stream.
- Physical limitations of existing operations may prohibit the installation of SCR or SNCR systems.

DAQ did not identify any instances where SCR or SNCR were demonstrated as technically feasible options for boilers rated at less than 10 MMBtu/hr firing gaseous or liquid fuels.

5C.4.3 $\underline{SO_2}$

Good combustion practices and use of low sulfur fuels are both technically feasible options for boilers with input ratings less than or equal to 10 MMBtu/hr.

Wet scrubbers are typically used to control SO_2 emissions from electrical utilities and industrial sources generating streams with high SO_2 contents, such as coal-fired power plants (USEPA, 2003). The SO_2 concentrations from natural gas or diesel-fired burners in boilers with input ratings less than or equal to 10 MMBtu/hr are too low for scrubbers to be technically feasible.

5C.4.4 VOC

Good combustion practices are technically feasible options for these applications.

Post-combustion controls, such as adsorption, thermal incinerators, and catalytic oxidizers, have not been demonstrated to be technically effective to control VOC emissions from combustion due to the low VOC concentrations from boilers with input ratings less than or equal to 10 MMBtu/hr.

5C.4.5 Ammonia

Ammonia emissions from boilers are assumed to be minimal and there are no known control technologies.

5C.5 - Ranking of Individual and Combined Controls:

5C.5.1 $\underline{PM_{2.5}}$

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1. Use of gaseous fuels combined with good combustion practices
2. Good combustion practices

5C.5.2 $\underline{NO_X}$

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1. Ultra-low NO_X burner (<9 ppm) and good combustion practices
2. Low NO_X burners (<30 ppm) and good combustion practices
3. Good combustion practices

5C.5.3 $\underline{SO_2}$

Good combustion practices combined with the use of low sulfur fuels is the only technically feasible control for natural gas and diesel-fired boilers with input ratings less than or equal to 10 MMBtu/hr.

5C.5.4 VOC

Good combustion practices is the only technically feasible control for natural gas and diesel-fired boilers with input ratings less than or equal to 10 MMBtu/hr.

5C.5.5 Ammonia

No control options were identified for ammonia emissions from natural gas and diesel-fired boilers with input ratings less than or equal to 10 MMBtu/hr.

5C.6 - Economic Feasibility:

DAQ evaluated the cost of retrofitting uncontrolled boilers with low NO_X (30 ppm) and ultra-low NO_X burners (9 ppm) as well as replacing uncontrolled boilers with low NO_X and ultra-low NO_X alternatives. Costs were obtained for boilers with input ratings of 10, 5, 2, and 0.5 MMBtu/hr. Emissions for this cost analysis were based on continuous operation (8,760 hours/year).

One important consideration when evaluating the cost effectiveness of retrofitting boilers with low NO_X and ultra-low NO_X burners is the age of the boilers. Typically, boilers have a service life of 20-40 years; the average age of the boilers installed at major sources in the $PM_{2.5}$ nonattainment area is 26 years. Retrofit costs were evaluated for boilers with 30, 20, and 10 years of in-service life remaining.

Table 5 shows a summary of the costs of the retrofit and replacement options. A detailed cost estimate is provided in Attachment A. Ultra-low NO_X retrofits and replacements are not technically feasible for boilers rated less than 2 MMBtu/hr, so costs for ultra-low NO_X burners were not evaluated for these smaller burners.

The cost per ton of NO_X removed for low NO_X burner retrofits of boilers ranges between $8,454 for a 10 MMBtu/hr boiler to $47,994 for a 0.5 MMBtu/hr boiler. The cost per ton of NO_X removed for ultra-low NO_X burner retrofits of boilers ranges between $7,255 for a 10 MMBtu/hr boiler to $10,363 for a 5 MMBtu/hr boiler.

The cost per ton of NOx removed for low NOx boiler replacement ranges between $13,929 for a 10 MMBtu/hr boiler to $57,969 for a 0.5 MMBtu/hr boiler. The cost per ton of NOx removed for ultra-low NOx boiler replacement ranges between $13,542 for a 10 MMBtu/hr boiler to $17,411 for a 5 MMBtu/hr boiler.

Many of the boilers rated at less than 10 MMBtu/hr currently in operation at major sources in the $PM_{2.5}$ nonattainment area are already equipped with low NO_X or ultra-low NO_X burners. DAQ evaluated the cost of upgrading existing low-NO_X boilers by either retrofitting the boilers with ultra-low NO_X burners or replacing these boilers with ultra-low NO_X boilers. The cost per ton of NO_X removed for ultra-low NO_X burner retrofits of boilers ranges between $24,735 for a 10 MMBtu/hr boiler to $35,332 for a 5 MMBtu/hr boiler. The cost per ton of NO_X removed for ultra-low NO_X boilers replacement are estimated at $46,173 for a 10 MMBtu/hr boiler and $59,366 for a 5 MMBtu/hr boiler.

5C.7 - <u>Evaluation of Findings & Control Selection:</u>

The economic feasibility analysis demonstrates that retrofit options and boiler replacements are generally not cost effective options for boilers under 5 MMBtu/hr. Retrofitting or replacing boilers between 5 and 10 MMBtu/hr could both be cost effective options depending on the boiler size, age, and hours of operation.

As shown in Table 5, the estimated costs for low NO_X burner retrofits start at $8,454 per ton of NO_X removed and boiler replacements start at $13,542. Retrofitting or replacing existing low-NO_X boilers with ultra-low NO_X boilers also proved to be cost prohibitive. Retrofits costs start at $24,735 per ton of NO_X removed and replacement costs start at $46,173.

DAQ recommends the use of natural gas as primary fuel and good combustion practices as BACT for the existing boilers operating at major sources within the nonattainment area. Diesel or fuel oil may only be used as backup fuel or in areas where natural gas is not available. The sulfur content of any diesel or fuel oil burned shall not exceed 15 ppm by weight.

An evaluation to determine whether retrofitting or replacing boilers between 5 and 10 MMBtu/hr with low-NOx or ultra-low NOx burners is economically feasible should be conducted on a case-by-case basis.

5C.8 - <u>Time for Implementation:</u>

Owners/operators have 30 days from the date of this document to conform with the BACT determination of good combustion practices, use of as primary fuel natural gas, and the use of diesel fuel not exceeding 15 ppm by weight as backup fuel or as primary fuel in areas where natural gas is not available.

Owners/operators shall evaluate the economic feasibility of retrofitting or replacing boilers between 5 and 10 MMBtu/hr with low-NOx or ultra-low NOx burners. If this evaluation shows that it is economically feasible to retrofit or replace boilers, construction and installation shall be completed within one year of the date of this document.

Table 2. Summary of BAAQMD NO_X Limits

Rule	Applicability Thresholds	Fuel	NO_X Limit	Applicability Dates
Regulation 9, Rule 7 - Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	> 2 to 5 MMBtu/hr	Natural Gas	30 ppmv	Applicable to all boilers at a source (new and existing). Existing boilers must meet applicable emission limits within two years of effective date (January 1, 2013 for boilers <10 MMBtu/hr and January 1, 2012 for boilers >=10 MmBtu/hr)
	>5 to <10 MMBtu/hr	Natural Gas	15 ppmv	
	10 to <20 MMBtu/hr	Natural Gas	15 ppmv	
Regulation 9, Rule 6 - Nitrogen Oxides Emissions from Natural Gas-Fired Boilers and Water Heaters	<0.075 MMBtu/hr	Natural Gas	20 ppmv	Applicable to boilers manufactured after January 1, 2011.
	0.075 – 2 MMBtu/hr	Natural Gas	20 ppmv	Applicable to boilers manufactured after January 1, 2013.

Table 3. Summary of SCAQMD NO_X Limits

Rule	Applicability Thresholds	Fuel	NO_X Limit	Applicability Dates
Rule 1146 - Emissions of oxides of nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	5 to <20 MMBtu/hr	Natural Gas	9 ppmv or 0.011 lbs/MMBtu	All units at a source must show compliance on or before January 1, 2015.
	<10 MMBtu/hr (Atmospheric Units only)	Natural Gas	20 ppmv	All units at a source must show compliance on or before January 1, 2014.
	All Units fired on non-gaseous fuels	Non-gaseous fuels	40 ppm	All units at a source must show compliance on or before January 1, 2008.
Rule 1146.1 - Emissions of oxides of nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	2 to <5MMBtu/hr	Natural Gas	9 ppmv or 0.011 lbs/MMBtu	All units at a source must show compliance on or before January 1, 2012 or January 1, 2014, depending on location.
	Atmospheric Units	Natural Gas	12 ppmv or 0.015 lbs/MMBtu	All units at a source must show compliance on or before January 1, 2014.
Rule 1146.2 - Emissions of oxides of nitrogen from Large Water Heaters and Small Boilers and Process Heaters	<0.4 MMBtu/hr	Natural Gas	20 ppmv	New units
	>0.4 to 2 MMBtu/hr	Natural Gas	20 ppmv	New units
	>0.4 to 2 MMBtu/hr	Natural Gas	30 ppmv	Existing

Table 4. Summary of SJAQMD NO_X Limits

Rule	Applicability Thresholds	Fuel	NO_X Limit	Applicability Dates
Rule 4306 - Boilers Steam Generators, and Process Heaters - Phase 3	5 to <20 MMBtu/hr	Natural Gas	Standard Option: 15 ppmv or 0.018 lb/MMBtu Enhanced Option: 9 ppmv or 0.011 lb/MMBtu	All units at a source must show compliance on or before December 1, 2008.
	5 to <20 MMBtu/hr	Liquid Fuel[1]	40 ppmv or 0.052 lb/MMBtu	
	Refinery Units 5 to 65 MMBtu/hr	Natural Gas	Standard Option: 30 ppmv or 0.036 lb/MMBtu Enhanced Option: No option	
Rule 4307 - Boilers Steam Generators, and Process Heaters - 2.0 MMBtu/hr to 5. MMBtu/hr	2 to <5MMBtu/hr	Natural Gas	Atmospheric Units: 12 ppmv or 0.014 lb/MMBtu Non-Atmospheric Units: 9 ppmv or 0.011 lb/MMBtu	New or replacement units. Effective date upon installation or on and after January 1, 2010 or January 1, 2016, depending on location.
	2 to <5MMBtu/hr	Natural Gas	30 ppmv or 0.036 lb/MMBtu	Existing Units
	3 to <5MMBtu/hr	Liquid Fuel	40 ppmv	Existing Units

Notes:
[1] NO_X limit for a dual fuel unit to be calculated using a weighted average approach, as described in Section 5.1.2 of Rule 4306.

Table 4. Summary of SJAQMD NO_X Limits (cont'd)

Rule	Applicability Thresholds	Fuel	NO_X Limit	Applicability Dates
Rule 4308 - Boilers Steam Generators, and Process Heaters - 0.075 MMBtu/hr to less than 2.0 MMBtu/hr	0.075 to 0.4 MMBtu/hr	Natural Gas	PUC Gas 20 ppmv or 0.024 lb/MMBtu Non-PUC Gas 77 ppmv or 0.093 lb/MMBtu	Effective after January 1, 2015
	0.075 to 0.4 MMBtu/hr	Liquid Fuel	77 ppmv or 0.093 lb/MMBtu	Effective after January 1, 2015
	0.4 to 2.0 MMBtu/hr	Natural Gas	PUC Gas 20 ppmv or 0.024 lb/MMBtu Non-PUC Gas 30 ppmv or 0.036 lb/MMBtu	Effective after January 1, 2015
	0.4 to 2.0 MMBtu/hr	Liquid Fuel	30 ppmv or 0.036 lb/MMBtu	Effective after January 1, 2015

Table 5. Summary of Cost per Ton of NO_X ($/ton) Removed

Control Option	Remaining In-Service Life	Boiler Size (MMBtu/hr)			
		10	5	2	0.5
Standard to Low NO_X Burner Retrofit[1]	30 years	$8,453.75	$6,843.56	$13,606.49	$44,281.11
	20 years	$8,785.62	$7,203.08	$14,104.30	$45,110.78
	10 years	$9,939.02	$8,452.60	$15,834.40	$47,994.29
Standard to Ultra-Low NO_X Burner Retrofit[1]	30 years	$7,254.62	$7,738.35	N/A	N/A
	20 years	$7,635.74	$8,324.69	N/A	N/A
	10 years	$8,960.32	$10,362.50	N/A	N/A
Low NO_X Boiler Replacement[1]	N/A	$13,928.76	$12,774.82	$21,819.01	$57,968.63
Ultra-Low NO_X Boiler Replacement[1]	N/A	$13,542.15	$17,411.48	N/A	N/A
Ultra-Low NO_X Burner Retrofit (30 ppm to 9 ppm)[2]	30 years	$24,735.41	$26,384.73	N/A	N/A
	20 years	$26,034.87	$28,383.90	N/A	N/A
	10 years	$30,551.15	$35,332.03	N/A	N/A
Ultra-Low NO_X Boiler Replacement (30 ppm to 9 ppm)[2]	N/A	$46,173.40	$59,366.26	N/A	N/A

Notes:
[1] Costs based on the emission reductions from a standard burner to a low NO_X or ultra-low NO_X burner.
[2] Costs based on the emission reductions from a low NO_X burner to an ultra-low NO_X burner.

N/A – Not applicable
Standard burner: 80 ppm
Low NO_X burners: 30 ppm
Ultra-low NO_X burners: 9 ppm

5D. - Space Heaters (Comfort Heaters)

5D.1 - Description:

For purposes of this BACT analysis, space heaters are defined as any furnaces used to heat commercial or industrial buildings. Space heaters are used in two different ways: in central heating systems and point source heating. In central heating systems, heat is generated in a central location and distributed throughout the building. Central heating is usually controlled by a thermostat. Point source heating provides supplemental heating to a room (SJVAPCD, 2014).

The most common fuel for these types of furnaces is natural gas; propane, fuel oil, heating oil, and used oil are also used. This BACT analysis was performed for space heaters fueled by natural gas and used oil (SJVAPCD, 2014).

R307-401-10 exempts certain pieces of equipment from the requirements of an approval order. This rule includes an exemption for comfort heating equipment rated at less than 1 MMBtu/hr fueled by fuel oil and natural gas fired equipment rated at less than 5 MMBtu/hr.

R307-401-14 has requirements for heating equipment using used oil as fuel. This rule exempts boilers burning used oil for energy recovery from the requirements of an approval order if the burner is rated at less than 1 MMBtu/hr and the used oil is not considered hazardous (i.e. does not exceed the concentration levels in R307-401-14(2)(b) and has a flash point above 100° F.).

5D.2 - Emissions Summary:

The primary pollutants from the combustion in space heaters are NO_X and CO. Particulates, SO_2, VOC, and HAP are emitted at lower levels. Emissions are summarized in the table below for both natural gas and used oil fuels.

Table 1. Representative Heater Emission Estimates

Pollutant	Emissions by Fuel Type (tpy)[1]	
	Used Oil[2,3,4]	Natural Gas[4,5]
NO_X	0.19	0.13
CO	0.05	0.11
PM_{10}	0.03	0.01
$PM_{2.5}$	0.03	0.01
SO_2	0.00	0.00
VOC	0.00	0.01
HAP	0.00	0.00

Notes:
[1]Heater size 300,000 MMBtu/hr
[2]Conversions factor of 140,000 Btu/gal (AP-42)
[3] Used oil emission factors not available, the emission factors in AP-42 Chapter 1.3 for fuel oil used as surrogates.
[4] For a conservative estimate, heaters assumed to operate 8,760 hours per year
[5]Uncontrolled emission factors in AP-42, Chapter 1.4 used.

5D.3 - Control Options:

This BACT analysis was performed for control options for $PM_{2.5}$ and $PM_{2.5}$ precursors (NO_X, SO_2, VOC, and ammonia). The following sources were evaluated to identify control options for space heaters.

- EPA's RBLC
- Technical documents, EPA fact sheets, and other applicable literature
- NSPS, NESHAP, and MACT regulations
- Utah State Rules
- SJVAPCD Current Rules and BACT Clearinghouse
- SCAQMD Current Rules
- BAAQMD Current Rules

The sections below provide a summary of each the control options found in each of the resources listed above. Available control options are described for each pollutant evaluated.

5D.3.1 $PM_{2.5}$

$PM_{2.5}$ emissions are generated when solid material is released during combustion. PM emissions are often released as ash-forming matter or carbon particles and are more prevalent as a result of combustion of solid fuels (Oland, 2002). This BACT analysis only evaluates natural gas and used oil fuels, so $PM_{2.5}$ emissions are anticipated to be relatively minor.

RBLC and Technical Documents

The following control technologies were identified as available options for $PM_{2.5}$ emissions from space heaters.

- Good combustion practices
- Use of gaseous fuels

NSPS, NESHAP, or MACT Regulations

There are no NSPS, MACT, or NESHAP regulations applicable to space heaters.

Utah State Rules

There are no Utah State rules applicable to $PM_{2.5}$ emissions from space heaters.

Other State Rules

There are no $PM_{2.5}$ limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5D.3.2 NO_X

NO_X emissions from combustion processes occur primarily through the thermal NO_X mechanism. The thermal NO_X mechanism consists of the thermal dissociation and subsequent reaction of N_2 and O_2 molecules in the combustion air. Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel (USEPA, 1998).

RBLC and Technical Documents

The following control technologies were identified as available options for NO_X emissions from space heaters.

- Good combustion practices
- Pre-combustion modifications (oven fire air, low excess air, air staging, etc)
- Combustion Controls
- FGR
- Low NO_X burners
- Ultra-low NO_X burners

NSPS, NESHAP, or MACT Regulations

There are no NSPS, MACT, or NESHAP regulations applicable to space heaters.

Utah State Rules

UAC R307-401-4 states that owners/operators shall install low oxides of nitrogen burners or equivalent oxides of nitrogen controls whenever existing fuel combustion burners are replaced. However, this rule does not specify NO_X levels that are considered "low oxides of nitrogen".

Other State Rules

Space heaters are not included in the SJVAPCD BACT clearinghouse database.

SCAQMD Rule 1111 (Reduction of NO_X Emissions from Natural-Gas-Fired, Fan-Type Central Furnaces) applies to commercial fan-type central furnaces with a heat input rating of less than 175,000 Btu/hr and a cooling rate of less than 65,000 Btu/hr. This rule states that manufacturers cannot supply, sell, offer for sale, or install natural gas-fired fan type central furnaces with NO_X emissions greater than 14 ng/J (or approximately 30 ppmvd) after April 1, 2015 for condensing and after October 1, 2015 for non-condensing furnaces.

There are no BAAQMD or SJVAPCD rules applicable to space heaters.

5D.3.3 SO_2

Sulfur dioxide emissions are a result of sulfur present in fuel combusted in space heaters. SO_2 emissions from space heaters are anticipated to be relatively minor.

RBLC and Technical Documents

The following control technologies were identified as available options for SO_2 emissions from space heaters.

- Good combustion practices
- Use of low sulfur fuels

NSPS, NESHAP, or MACT Regulations

There are no NSPS, MACT, or NESHAP regulations applicable to space heaters.

Utah State Rules

There are no Utah State Rule applicable to SO_2 emissions from space heaters.

Other State Rules
There are no SO_2 limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5D.3.4 VOC

VOC emissions from combustion occur due to incomplete combustion. VOC emissions are generated when there is insufficient time at high temperature to complete the final step in hydrocarbon oxidation (USEPA, 1998). The combustion of natural gas and fuel oil in space heaters will result in minor VOC emissions.

RBLC and Technical Documents
The following control technologies were identified as available options for VOC emissions from space heaters.

- Good combustion practices

NSPS/NESHAP, or MACT
There are no NSPS, MACT, or NESHAP regulations applicable to space heaters.

Utah State Rules
There are no Utah State Rule applicable to VOC emissions from space heaters.

Other State Rules
There are no VOC limits in the rules of the other air quality districts in other states evaluated (SJVAPCD, SCAQMD, or BAAQMD).

5D.3.5 Ammonia

Ammonia emissions from combustion of natural gas and diesel fuel are anticipated to be minimal. Ammonia emissions from combustion are more likely to result from ammonia slip in SCR or SNCR units, rather than from the combustion process.

A 1994 EPA document evaluated available ammonia emission factors for ammonia and found that the NAPAP was the only inventory available at the time to include ammonia emission factors for combustion sources. The recommended emission factors for combustion sources are 0.49 $lb/10^6\ ft^3$ for natural gas combustion in commercial boilers and 0.8 lb/1,000 gal for fuel oil combustion (Battye, Battye, Overcash, & Fudge, 1994).

There are no known control technologies to control ammonia emissions from space heaters.

Due to the lack of available data and the anticipated minimal ammonia emissions from combustion process, BACT was not evaluated for this pollutant.

5D.4 - Technological Feasibility:

5D.4.1 $PM_{2.5}$

Use of gaseous fluids and good combustion practices are technically feasible options to control $PM_{2.5}$ emissions from combustion.

5D.4.2 NO_X

Good combustion practices, combustion controls, FGR, low NO_X burners, and ultra-low NO_X burners are technically feasible options for burners in space heaters. The lowest NO_X emission levels that can be technically achieved in burners rated between 5 and 3 MMBtu/hr is 9 ppm. Commercially available burners for furnaces can typically achieve NO_X emissions as low as 30 ppm (SJVAPCD, 2014).

FGR is one of the main reduction methods for low-NO_X or ultra-low NO_X burners. FGR will not be evaluated as a separate control in this BACT analysis because many of the existing burners may not have the proper mechanical construction to accommodate FGR and retrofitting existing burners may drastically impact the burner efficiency.

Pre-combustion modifications are technically feasible, but will often result in minimal emission reductions. Additionally, these modifications will reduce burner efficiency and increase fuel demand, which can consequentially negate emissions reductions obtained by the modification (Hansen & Hanson, 2017). Therefore, these modifications will not be further considered as control options.

Combustion controls improve the fuel to air ratio and the combustion efficiency of the burner, which reduces the fuel consumption of the burner (Hansen & Hanson, 2017). NO_X emissions will be reduced as a consequence of reducing the fuel consumption. However, the NO_X concentration of the exhaust will remain the same. For instance, if a burner operates a burner with a NO_X rating of 60 ppm, combustion controls will reduce how much fuel the burner consumes but the burner rating will remain at 60 ppm. Combustion controls will reduce actual emissions through fuel consumption; however, this decrease cannot be effectively quantified for permitting purposes. Therefore, combustion controls will not be further evaluated as part of this BACT analysis despite being technically feasible.

5D.4.3 SO_2

Good combustion practices and use of low sulfur fuels are both technically feasible options for space heaters.

5D.4.4 VOC

Good combustion practices are technically feasible options for these applications.

5D.4.5 Ammonia

Ammonia emissions from space heaters are assumed to be minimal and there are no known control technologies.

5D.5 - Ranking of Individual and Combined Controls:

5D.5.1 $PM_{2.5}$

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1) Use of gaseous fuels combined with good combustion practices

2) Good combustion practices

5D.5.2 NO$_X$

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1) Ultra-low NO$_X$ burner (<9 ppm) combined with) and good combustion practices
2) Low NO$_X$ burners (<30 ppm) combined with) and good combustion practices
3) Good combustion practices

5D.5.3 SO$_2$

Good combustion practices combined with the use of low sulfur fuels are the only technically feasible controls for natural gas and fuel oil-fired space heaters.

5D.5.4 VOC

Good combustion practice is the only technically feasible control for natural gas and fuel oil-fired space heaters.

5D.5.5 Ammonia

No control options were identified for ammonia emissions from natural gas and fuel oil-fired space heaters.

5D.6 - Economic Feasibility:

As shown in Table 1, emissions from space heaters are less than 0.2 tpy. Any retrofit or replacement option would result in negligible emission reductions and is not anticipated to be cost effective.

5D.7 - Evaluation of Findings & Control Selection:

DAQ recommends that BACT for space heaters is the use of gaseous fuel and good combustion practices. Space heaters fueled by used oil shall only burn fuels in accordance with R307-401-14(2)(b).

5D.8 - Time for Implementation:

Owners/operators have 30 days from the date of this document to comply with the BACT determination of good combustion practices, use of natural gas as a primary fuel, and the use of used oil that complies with the limits in R307-401-14(2)(b).

6. - Cooling Towers

6.1 - Description:

Cooling towers are heat exchangers used to remove heat and cool a process fluid, such as water or air. Cooling towers are commonly used in various industrial and commercial processes, from refineries and power plants to small HVAC systems. Different heat transfer mediums can be used, but water is the most common (USEPA, 2015).

The two primary classifications of cooling towers are dry and wet towers. A wet system relies on water evaporation to provide cooling as air passes through the cooling water in the tower. The most common type of wet system is a recirculated cooling system, where water is continuously recirculated through the system. Heat transfer primarily occurs via evaporation, but also via convective heating of the air that passes through the tower. Wet systems are further classified as natural draft and induced draft systems. A natural draft system achieves flow through the tower by the difference in the density between the cold air entering at the base and the warm air leaving the top of the tower. An induced air system uses fans to achieve flow through the tower (Baker, Feely, Comisac, Burns, & Micheletti, 2001).

In dry cooling towers, heat transfer occurs without evaporation of water. This involves large, finned-tube water-to-air heat exchangers through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water. This process usually requires high operating pressures and can be costly to implement (Baker et al., 2001).

Cooling towers use both indirect and direct contact cooling methods. Indirect contact cooling passes the hot process fluid though heat exchangers and condensers. In indirect systems, heat is dissipated to the process cooling water without contact with the process fluid. Direct contact cooling involves cooling the process fluid by making direct contact with the cooling water (Brady, Brush, & Burmark, 1998).

The cooling towers evaluated in this BACT analysis include evaporative cooling towers using both direct and indirect cooling methods.

6.2 - Emissions Summary:

PM and VOC emissions are the most common pollutants entrained in cooling tower water. Table 1 below summarizes the emission factors included in Table 13.4-1 of EPA AP-42 Chapter 13.2.4. VOC emission factors are provided for petroleum refineries in AP-42 Chapter 5.1, Table 5.1-3. These emission factors are considered conservative, especially for cooling towers with medium to high TDS levels(Reisman & Frisbie, 2002).

Table 1. AP-42 Emission Factors			
Type of Industry	Emission Factor (lb/10^6 gal)		
	VOC[1]	PM[2]	Total Liquid Drift[2,3]
Refineries	0.7	19	170
Chemical Manufacturing	0.7	19	170
Other	NA	19	170

Notes:
[1] AP-42 Section 5.1, Table 5.1-3 for controlled emissions. Control consists of monitoring VOC concentration in circulation water.
[2] AP-42 Section 13.4, Table 13.4-1, for TDS content of 12,000 ppm
[3] Total liquid drift emission factor can be multiplied by the total dissolved solids content of the circulating water to obtain a PM emission factor a specific to the process water of a source

An alternative method for estimating emissions from cooling towers consists of multiplying the TDS concentration of the cooling water by the cooling tower flow rate and the drift eliminator emission factor (SCAQMD, 2006). Table 2 below shows representative emissions for different cooling tower sizes (1,500 gpm, 5,000 gpm, and 20,000 gpm), TDS concentrations (1,000 ppmw and 6,000 ppmw), and a drift rate of 0.001%.

Table 2. Example Cooling Tower Emissions			
Operating Parameters and Emissions	Cooling Tower Size (gpm)		
	1,500	5,000	20,000
Operating Hours	8,760	8,760	8,760
Drift Loss (%)	0.001	0.001	0.001
Scenario 1 – TDS 1,000 ppmw			
TDS (ppmw)	1,000	1,000	1,000
PM Emissions (lb/year)	65.75	219.18	876.70
PM Emissions (tpy)	0.03	0.11	0.44
PM_{10} Emissions (tpy)[1]	0.005	0.02	0.07
$PM_{2.5}$ Emissions (tpy)[2]	0.003	0.01	0.04
Scenario 2 – TDS 6,000 ppmw			
TDS (ppmw)	6,000	6,000	6,000
PM Emissions (lb/year)	394.52	1,315.05	5,260.20
PM Emissions (tpy)	0.20	0.66	2.63
PM_{10} Emissions (tpy)[1]	0.03	0.10	0.39
$PM_{2.5}$ Emissions (tpy)[2]	0.02	0.06	0.24

Notes:
[1]Assumes 85% of PM particles are greater than PM_{10} (Reisman & Frisbie, 2002)
[2]Assumes 60% of PM_{10} particles are greater than $PM_{2.5}$ (USEPA, 1995)

6.3 - Control Options:

This BACT analysis was performed for control options for $PM_{2.5}$ and VOC. The following sources were evaluated to identify control options for cooling towers.

- EPA's RBLC
- Technical documents and EPA fact sheets, EPA Air Pollution Control Cost Manual

- NSPS, NESHAP, and MACT regulations
- Utah State Rules
- SJVAPCD Current Rules and BACT Clearinghouse
- SCAQMD Current Rules
- BAAQMD Current Rules

The sections below provide a summary of each of the control options found in the resources listed above. Available control options are described for each pollutant evaluated.

6.3.1 $PM_{2.5}$

$PM_{2.5}$ emissions are generated as water evaporates from a cooling tower and small droplets of water become entrained in the air stream and are carried out as drift droplets. The drift droplets will often contain impurities from the water flowing through the system, so they are considered a type of emission (USEPA, 2015). These impurities are often from water treatment additives, such as anti-fouling or anti-corrosion additives, or from direct contact between the cooling water and the process fluid (Brady et al., 1998).

RBLC and Technical Documents

The following control technologies were identified as available options for $PM_{2.5}$ emissions from cooling towers:

- Use of dry cooling (no water circulation) heat exchanger units
- High efficiency drift eliminators
- Limitations on TDS in the circulating water

Dry Cooling Towers

Dry cooling towers use fans to move dry ambient air through the towers and cool the process stream. Because these towers do not rely on the evaporation of water for heat transfer, they do not generate drift emissions (Baker et al., 2001).

Drift Eliminators

High efficiency drift eliminators remove droplets before the air is discharged to the atmosphere. Drift eliminators are rated by the percentage of emissions from the cooling tower water circulation rate. The drift rates in the RBLC database range between 0.0005% and 0.02%; the majority of drift rates reported are under 0.001%.

Limitations on TDS in Circulating Water

Dissolved solids in the circulating water increase in concentrations as the circulating water evaporates (USEPA, 2015). TDS can also occur as a result of the addition of anti-corrosion or anti-biocide additives. A filtration system can be used to reduce TDS concentrations in circulating water (Reisman & Frisbie, 2002). Monitoring the TDS content in circulation water is an effective approach to ensure that excess emissions are not generated as a result of high TDS levels in circulation water. The TDS concentration limitations in the RBLC database range between 1,000 mg/L and 6,009 mg/L.

NSPS, NESHAP, or MACT Regulations
40 CFR 63 Subpart Q (National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers) applies to new and existing industrial process cooling towers operated with chromium-based water treatment chemicals that are either major sources of HAP or are integral parts of major sources. This subpart states that no owners/operators of cooling towers use chromium-based water treatment chemicals.

Utah State Rules
There are no Utah State rules applicable to cooling towers.

Other State Rules
The SJVAPCD BACT database lists cellular type drift eliminators as BACT for cooling towers.

Other state agencies (SJVAPCD, SCAQMD, BAAQMD) have rules that limit hexavalent chromium emissions (SJVAPCD Rule 7012; SCAQMD Rule 1404; and BAAQMD Regulation 11 Rule 10). This BACT analysis focuses on $PM_{2.5}$ and precursors, so these rules will not be evaluated.

6.3.2 VOC
VOC emissions are caused when a VOC-containing process stream contaminates circulation water due to a leak in the system or if the circulation water is treated with VOC-containing material (TCEQ, 2003). VOC emissions from cooling towers are more likely to occur in petroleum refineries or chemical manufacturing

RBLC and Technical Documents
Identifying leaks by routinely monitoring VOC concentrations in circulation water was the only control technology identified as an available option for VOC control from cooling towers.

Elevated VOC concentrations can be an indication of leaks in the system. By routinely monitoring VOC concentrations in circulation water, leaks can be identified and repaired. The El Paso Method is commonly used to monitor VOC concentrations in circulation water (TCEQ, 2003). TCEQ established a VOC concentration of 0.08 ppmw for identifying a leak in the system. The RBLC database identified a VOC limit of 0.05 ppm.

NSPS, NESHAP, or MACT Regulations
40 CFR 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries) specifies the monitoring requirements to identify VOC leaks. This Subpart specifies leak action levels of 6.2 ppmv for existing sources and 3.1 ppmv for new sources in 60.654(c)(4)(i) and (ii), respectively.

Utah State Rules
There are no Utah State rules applicable to cooling towers.

Other State Rules
The SJVAPCD BACT database does not list BACT for VOC emissions from cooling towers.

Other state agencies (SJVAPCD and SCAQMD) have rules that limit hexavalent chromium emissions (SJVAPCD Rule 7012 and SCAQMD Rule 1404). BAAQMD Regulation 11 Rule 10 limits the emissions of both hexavalent chromium and total hydrocarbons from petroleum refinery cooling towers. This rule defines a leak action level of 84 ppbw in cooling water for existing units and 42 ppbw for new/modified units measured in circulation water; or 6 ppmv as measured in stripped air by a continuous hydrocarbon analyzer.

6.4 - Technological Feasibility:

6.4.1 $PM_{2.5}$ Controls

Dry cooling towers are costly to implement and maintain. They are inherently less effective than wet cooling towers because they do not rely on evaporative heat transfer. They are typically more suited for large installations, such as large power plants (Baker et al., 2001). Therefore, this option is not considered technically feasible.

Drift eliminators are common controls for cooling towers. Drift rates as low as 0.0005% are technically feasible. According to discussions with manufacturers and the data available in the RBLC database, a drift rate of 0.001% is the most common and technically achievable efficiency. The achievable drift rate depends on a variety of factors, such as tower type (field erected vs packaged), flow pattern (crossflow vs counterflow), and draft system (natural vs induced draft).

Limiting TDS in circulating water is an effective control when used in conjunction with drift eliminators. Specific TDS limitations vary based on the process and the characteristics of the water at the source.

6.4.2 VOC Controls

A leak detection program is the only technically feasible control for VOC emissions from cooling towers used to cool process streams containing VOC.

6.5 - Ranking of Individual and Combined Controls:

6.5.1 $PM_{2.5}$

The technically feasible control technologies were ranked from most effective in reducing emissions to least effective. The identified technologies were ranked as follows:

1. Combination of drift eliminator and TDS limitation
2. Drift eliminators
3. TDS limitation

6.5.2 VOC Controls

A leak detection program is the only available option for controlling VOC emissions from cooling towers.

6.6 - Economic Feasibility:

DAQ contacted several vendors to evaluate the economic feasibility of retrofitting drift eliminators to increase capture efficiency. These vendors indicated that the cost for retrofitting drift eliminators depends on the specific design of the cooling tower and the industrial process

(Campos, 2017). This BACT analysis is intended to be a general evaluation of the control options available for each emission source and is not an evaluation of the specific emission units in operation. Therefore, an economic feasibility evaluation for retrofitting drift eliminators was not prepared for this BACT analysis.

Similarly, economic analyses of water treatment systems to limit TDS concentrations in circulation water and VOC leak detection programs were not evaluated as these measures will vary significantly for each process.

6.7 - Evaluation of Findings & Control Selection:

The cooling towers operating at major sources in the $PM_{2.5}$ nonattainment area are equipped with drift eliminators with loss rates ranging from 0.2% to 0.0005%. Routine monitoring of TDS concentrations in circulating water is a common operating practice for these cooling towers.

DAQ has determined that BACT for $PM_{2.5}$ emissions from cooling towers is drift eliminators combined with TDS limitations. A specific drift eliminator efficiency and TDS limitation is not specified in this BACT analysis as these limitations are dependent on the specific cooling tower design and the industrial process.

DAQ has determined that BACT for VOC emissions from cooling towers is implementation of a leak detection program, in accordance to an applicable Subpart and/or with the El Paso Method. This is only applicable to process streams that may contain VOC or if the circulated water is treated with VOC-containing materials.

6.8 - Time for Implementation:

All cooling towers in operation at major sources in the $PM_{2.5}$ nonattainment area are equipped with drift eliminators. Owners/operators that do not have an existing TDS limitation shall implement a program for monitoring TDS concentrations within 180 days of this document. Owners/operators dealing with process streams that may contain VOC or circulated water treated with VOC-containing materials shall implement a program for monitoring VOC leaks within 180 days of this document.

7. - Dry Cleaning Units – Various Solvents

7.1 - Description:

Dry cleaning is the process of cleaning fabrics not suited to regular washing with water. ("Document Display | NEPIS | US EPA," 2002) Washing is done by agitating the items to be cleaned in a solvent bath. The next step is the extraction phase. During the extraction phase, excess solvent is removed in a spin cycle by using centrifugal force. The final step is drying. Drying is conducted by tumbling the items in a warm air stream in order to vaporize and remove the solvent. Filters are installed on all dry cleaning processes to remove suspended and dissolved materials from the solvent. ("Document Display | NEPIS | US EPA," 2002) The two types of filters most commonly employed are powder filters and cartridge filters. Foreign objects that are incompatible with the solvent are removed, such as pens, or buttons, depending on the solvent used. Perchlorethylene, trichloroethylene, and petroleum spirits (Stoddard solvent) are the most common dry cleaning agents, although other solvents are used in addition to these three. ("Document Display | NEPIS | US EPA," 2002)

The dry cleaning industry can be divided into three types: commercial, industrial, and coin-operated. The most common type is the commercial dry cleaner, which offers dry cleaning services to the general public. Industrial dry cleaners are the largest sources and are usually operated in conjunction with a service that rents uniforms and other items to commercial, industrial, or institutional clients. Coin-operated dry cleaners are used directly by the consumer. ("Document Display | NEPIS | US EPA," 2002)

Dry cleaning activities that use more than one piece of equipment to complete the steps are called transfer processes. When one machine is used for all three steps, it is called a dry-to-dry process. Fugitive emissions from both transfer and dry-to-dry processes can occur from fittings and seals around the cylinder door, button trap, base tank, recirculating pump, and filter housing. ("Document Display | NEPIS | US EPA," 2002)

7.2 - Emissions Summary:

The VOC emissions from dry cleaning depend on the solvent used and the size of the equipment.

7.3 - Control Options:

This BACT analysis was performed for controls options for VOC emissions.

NSPS, MACT, and State of Utah regulations apply to dry cleaning.

- 40 CFR 60, Subpart JJJ, Standards of Performance for Petroleum Dry Cleaners
- 40 CFR 63, Subpart M, National Emissions Perchlorethylene Air Emissions Standards for Dry Cleaning Facilities
- The State of Utah has adopted the federal regulations.

Lint filtration, muck filtration, absorptive cartridge filters (ACF), polishing filter, and cooked powder residue (CPR) are contained within the dry cleaning units. Sealing the dry cleaning units eliminates possible sources of VOC. VOC emissions from dry cleaning units are considered fugitive emissions. ("Document Display | NEPIS | US EPA," 2002)

Solvent is contained in a sealed unit. The solvent passes through a chilled container to reclaim as much solvent as possible. (“Document Display | NEPIS | US EPA,” 2002)

Drying is achieved by heating the solvent at a steady state temperature, usually just hot enough to evaporate the solvent from the fabric. (“Document Display | NEPIS | US EPA,” 2002)

The following items will reduce VOC emissions from dry cleaning equipment, and are required by federal regulations.

Perchlorethylene

- Vent dryer exhaust through a carbon absorber or equivalent device with an outlet concentration <100 ppmv (Coin operated dry cleaners are exempt.).
- Reduce filter residue to <25% Perchlorethylene and still residue to <60% Perchlorethylene.
- Drain filter cartridges for >24 hours or until dry before disposal.
- Immediately repair liquid and vapor leaks.

Large Petroleum Dry Cleaners

- Use a solvent recovery dryer to reduce emissions by 81%.
- Use a cartridge filter.
- Improve operation of distillation unit.
- Repair liquid and vapor leaks within 3 working days.

Petroleum Dry Cleaners 40 CFR 60, Subpart JJJ

- Applicability Size: >84 pound capacity
- Use a solvent recovery dryer. Use a cartridge filter. Drain the filter in sealed housing for at least 8 hours prior to removal.
- Inspect every 15 days and repair all vapor and liquid leaks within the next 15-day period

Existing Systems (installed prior to September 22, 1993)

- Route gas streams within dry cleaning machine through a refrigerated condenser or equivalent control device or through a carbon absorber.
- Contain transfer machine located at a major source in a room enclosure under negative pressures.

New Systems

- Route gas stream within dry cleaning machine through a refrigerated condenser or equivalent control device.
- Eliminate emissions during transfer of articles between washer and dryer.
- If at a major source, route gas streams within dry cleaning machine through a carbon absorber or equivalent device before or as the door are opened.

Each refrigerated condenser on a dry-to dry machine, dryer, or reclaimer

- Shall not release gas stream within machine while machine drum is rotating.

- Shall have an outlet temperature less than 45°F.
- Shall have a diverter valve that prevents air drawn in when the door is open from passing through the refrigerated condenser.

Each refrigerated condenser on a washer

- Shall not vent gas stream within machine until open door opens.
- Shall have a temperature drop of at least 20°F.
- Shall not use the same condenser coil that is used by a dry-to-dry machine, dryer, or reclaimer.

Each carbon absorber

- Shall not be bypassed.
- If used on an existing machine or on a new machine immediately upon door opening, outlet concentration at the end of the last cycle before regeneration must be equal to less than 100ppmv.
- If used on a new machine prior to door opening, the concentration inside the drum at the end of the cycle must be equal to or less than 300 ppmv.

Each room enclosure

- Shall vent all air through a carbon absorber or equivalent control device.
- Carbon absorber cannot be the same one used for the dry cleaning machine.

7.4 - <u>Technological Feasibility:</u>

The control options described above are generally technically feasible for a variety of dry cleaners.

7.5 - <u>Ranking of Individual and Combined Controls:</u>

1. Sealing the units by eliminating any possible sources of venting is critical to the operation of the units. (“Document Display | NEPIS | US EPA,” 2002)
2. The solvent is contained in a sealed unit by passing through a chilled container to reclaim as much as possible. (“Document Display | NEPIS | US EPA,” 2002)
3. Drying is achieved by heating the solvent at a steady state temperature, usually just hot enough to reclaim solvent from the fabric. Carefully measuring the temperature is important for the solvent used at the site. (“Document Display | NEPIS | US EPA,” 2002)
4. Lint, muck, and ACF, and CPR are a normal part of the use of a dry cleaning unit and should be dried in the unit before removing them to dispose of materials. (“Document Display | NEPIS | US EPA,” 2002)

7.6 - <u>Economic Feasibility:</u>

The listed control options are required by federal regulations; therefore, the applicable requirements are considered to be economically feasible.

7.7 - <u>Evaluation of Findings & Control Selection:</u>

Compliance with the applicable federal regulations and good work practices is considered BACT for dry cleaners.

7.8 - **Time for Implementation:**

New sources should comply with the federal requirements upon startup. Existing sources should be currently in compliance with the federal requirements.

8. - Emergency Engines

8.1 - Description:

This section includes reciprocating internal combustion engines. These engines are used during emergencies or when power is interrupted from the local utility. Engines provide mechanical energy to a generator that produces electricity. Diesel-fired engines, natural gas-fired engines, and propane-fired engines are included in this section.

8A. - Diesel-Fired Emergency Generators <200 hp

8A.1 - Description:
This source category is for emergency engines that are relatively small, rated less than 200 hp that use diesel fuel. This source category can be found in any kind of industrial, commercial, or institutional setting. Emergency engines are typically used to provide power for sources in emergency situations, when electric power from the public utilities is interrupted. Emergency engines are also typically operated weekly or monthly at zero or low loads for regular maintenance and testing to ensure proper engine operations.

8A.2 - Emissions Summary:
This source category could represent a variety of different engines with different sizes and ages. The emissions from these engines vary greatly. To be conservative, base emissions were calculated assuming an older engine, not subject to the standards in 40 CFR 60 Subpart IIII. Emissions were calculated for the following engine sizes: 50, 100, 150, and 190 hp. Emission estimates used emission factors from AP-42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1 (United States Environmental Protection Agency, 1996a, p. 3).

This source category is capable of emitting direct $PM_{2.5}$, and the following $PM_{2.5}$ precursor pollutants: SO_2, NO_X, and VOC. To determine direct $PM_{2.5}$ from AP-42 emission factors, the CEIDARS List with $PM_{2.5}$ fractions for Internal Combustion – Distillate and Diesel-Except Electric Generation $PM_{2.5}$ Fraction of PM_{10} of 0.991 was used (Mike Krause & Steve Smith, Ph.D., 2006). Based on an EPA guidance memorandum from John S. Seitz to Region Directors (John S. Seitz, 1995), and a response to William O'Sullivan, Director of the New Jersey Division of Air Quality, from EPA Region 2 Chief of the Permitting Section Steven C. Riva (Steven C. Riva, 2006), a total of 200 operating hours per year was used to calculate the PTE for this source category. The 200 operating hours will adequately cover the time when the emergency engine is used for maintenance, testing, and emergency situations.

8A.3 - Control Options:
The following sources were reviewed to identify available control technologies:
- EPA's RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA's Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state regulations
- 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
- Various state-specific example permits
- A thorough literature search using the Google search engine

After a review of the above sources, the DAQ determined that many state and federal regulations provide specific exemptions for the control and applicability of various regulations and control devices to emergency engines. The following control options were found for controlling emissions from stationary diesel engines:

Control Options for $PM_{2.5}$:

- Catalyzed Diesel Particulate Filter (CleanAIR Systems, 2009)
- Diesel Oxidation Catalyst (CS, 2009)
- Diesel Particulate Filter (CS, 2009)

Control Options for NO_X:

- Exhaust Gas Recirculation (CS, 2009)
- NO_X Adsorber Catalyst (CS, 2009)
- Selective Catalytic Reduction (CS, 2009)
- Turbocharging and aftercooling (US EPA, 1993)
- Engine Ignition Timing Retardation (US EPA, 1993)
- Modifying air-to-fuel ratio (US EPA, 1993)

Control Options for SO_2:

- Ultra-Low Sulfur Diesel Fuel (Bradley Nelson, 2010)

Control Options for VOC:

- Catalyzed Diesel Particulate Filter (CS, 2009)
- Diesel Oxidation Catalyst (CS, 2009)

Additional control options for all pollutants include replacement of older engines with new engines, and adherence to emission limitations contained in 40 CFR 60 Subpart IIII. 40 CFR 63 Subpart ZZZZ contains no additional requirements for emergency engines beyond operational and maintenance practices. For older engines that do not comply with an emission limitation in 40 CFR 60 Subpart IIII, emissions could be controlled by one of the above methods.

8A.4 - Technological Feasibility:

Many of the above control options are possible control options for stationary diesel engines used for prime operations, rather than emergency operations. Due to the unique operating scenario of emergency diesel engines, several of the technologies are not technically feasible.

Control Options for $PM_{2.5}$:

Catalyzed Diesel Particulate Filter

This control technology has been approved under the California Air Resources Board's (CARB) verification procedure for emergency engines (California Air Resources Board, 2017). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Oxidation Catalyst

Miratech supplies a CARB Level 3 Plus Verified diesel oxidation catalyst in series with a diesel particulate filter designed for use with emergency backup generator units ("LTR Diesel Oxidation Catalyst," n.d.). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Particulate Filter

CARB has concluded that diesel particulate filters are technologically feasible with some additional operational and monitoring conditions (Matt Baldwin, 2016). Drawbacks exist for the

use of diesel particulate filters for emergency engines. If an engine is run at a low load, the filter may clog quickly and the engine would need to be run at a higher load to clear the filter. Therefore, the total PM controlled by the filter will most likely be less than the NO_X emitted from running at the higher load. According to case studies, multiple sources have successfully installed diesel particulate filters on emergency diesel engines with minimal problems (Manufacturers of Emission Controls Association, 2009). Therefore, this is a technically feasible control option for emergency diesel engines.

Control Options for NO_X:

Exhaust Gas Recirculation

Exhaust gas recirculation is typically incorporated in new stationary diesel engines automatically. Exhaust gas recirculation can result in fouled air intake systems, combustion chamber deposits, and increased engine wear rates on stationary diesel engines, but is feasible (US EPA, 1993). Therefore, this is a technically feasible control option for new emergency diesel engines. Some exhaust gas recirculation technologies can also be retrofitted to older engines (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency diesel engines.

NO_X Adsorber Catalyst

This is an emerging control technology that has been approved for on-road diesel engines and is currently being researched for adaptation for controlling stationary diesel engines. There are no real-world examples of this control technology being used to control emissions from stationary diesel emergency engines (Bradley Nelson, 2010). Therefore, this is not a technically feasible control option for stationary emergency diesel engines.

Selective Catalytic Reduction

CARB has determined that selective catalytic reduction, while technologically feasible in some cases, has challenges when applying it to emergency diesel engines. Emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine (Matt Baldwin, 2016). This could also be a challenge for many emergency engine applications. Therefore, this is not a technically feasible control option for stationary emergency diesel engines.

Turbocharging and aftercooling

Turbocharging and aftercooling is typically incorporated in new stationary diesel engines automatically. Therefore, this is a technically feasible control option for new emergency diesel engines. Existing emergency engines can be modified to be equipped with a turbocharger (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency diesel engines.

Engine Ignition Timing Retardation

Ignition timing can be adjusted on new and existing diesel engines; however, an electronic injection control system is needed to ensure sustained NO_X emissions reductions (US EPA, 1993). Most new engines have electronic injection control systems automatically installed;

therefore, this is a technically feasible option for new emergency diesel engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency diesel engines.

Modifying air-to-fuel ratio
New emergency diesel engines have electronic injection control systems automatically installed that can modify the air-to-fuel ratio to ensure a lean burn scenario. Therefore, this is a technically feasible option for new emergency diesel engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency diesel engines.

Control Options for SO_2:
Ultra-Low Sulfur Diesel Fuel
Ultra-low sulfur diesel fuel is a standard requirement in 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for newer and certain existing stationary engines. The DAQ has also incorporated these sulfur requirements into many existing permits. Therefore, this is a technically feasible control option.

Control Options for VOC:
Catalyzed Diesel Particulate Filter
This control technology has been approved under CARB's verification procedure for emergency engines (California Air Resources Board, 2017). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Oxidation Catalyst
Miratech supplies a CARB Level 3 Plus Verified diesel oxidation catalyst in series with a diesel particulate filter designed for use with emergency backup generator units ("LTR Diesel Oxidation Catalyst," n.d.). Therefore, this is a technically feasible control option for emergency diesel engines.

8A.5 - <u>Ranking of Individual and Combined Controls:</u>

Control Options for $PM_{2.5}$:

1. Catalyzed Diesel Particulate Filter: 85% - 90% (case dependent) (Bradley Nelson, 2010)
2. Diesel Particulate Filter: 85% – 90% control efficiency (case dependent) (Bradley Nelson, 2010)
3. Diesel Oxidation Catalyst: 20% - 50% control efficiency (Bradley Nelson, 2010)

Control Options for NO_X:

1. Exhaust Gas Recirculation: 25% - 50% control efficiency (Bradley Nelson, 2010)
2. Engine Ignition Timing Retardation & Modifying air-to-fuel ratio: 2.7% - 48% control efficiency (Eric Patton, P.E., 1998)
3. Engine Ignition Timing Retardation: 20% - 45% control efficiency (US EPA, 1996b, p. 4)
4. Turbocharging and aftercooling: 3% - 35% control efficiency (Eric Patton, P.E., 1998)
5. Modifying air-to-fuel ratio: 7% - 8% control efficiency (US EPA, 1996b, p. 4)

Control Options for SO_2:

1. Ultra-Low Sulfur Diesel Fuel: 5% - 30% reduction in SO_2 (Bradley Nelson, 2010)

Control Options for VOC:

1. Catalyzed Diesel Particulate Filter: 90% control efficiency (Bradley Nelson, 2010)
2. Diesel Oxidation Catalyst: 90% control efficiency (Bradley Nelson, 2010)

8A.6 - Economic Feasibility:

The cost of purchasing a new diesel engine subject to Tier 2 or Tier 3 standards can range from $10,000 for a 100 hp engine to $180,000 for a 1,500 hp diesel engine (Bradley Nelson, 2010).

For a 100 hp engine, the difference of emissions of an existing engine and a new engine is as follows:

- 0.018 tpy of $PM_{2.5}$
- 0.244 tpy of NO_X

The following assumptions were used in this analysis:

- The Engine Size is 100 hp
- The cost of a 100 hp engine is $10,000
- An annual interest rate of 7% (US EPA, 2002)
- The economic life of each engine is 20 years
- Negligible annual maintenance costs due to costs most likely being similar to current costs with an existing engine

Based on these assumptions, the cost/ton removed for replacing an existing engine with a new engine is as follows:

- $40,795 for $PM_{2.5}$
- $3,009 for NO_X

Based on the cost above for $PM_{2.5}$ control, it is not cost effective to purchase a new engine subject to the most stringent Tier 3 standards specified in 40 CFR 60 Subpart IIII. However, based on the cost above for NO_X control, it could potentially be cost effective to purchase a new engine subject to the newest Tier 3 standards for emergency engines in this size source category as specified in 40 CFR 60 Subpart IIII.

Control Options for $PM_{2.5}$:

1. Catalyzed Diesel Particulate Filter: Based on Table 5-3 on page 61 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $42,509 to $134,461. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.
2. Diesel Particulate Filter: Based on Table 5-3 on page 61 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $42,509 to $134,461. The costs in this table were

based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines. Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine (Bradley Nelson, 2010). This control option is not cost-effective for this category.

3. Diesel Oxidation Catalyst: Based on Table 5-6 on page 65 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $47,683 to $161,159. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.

Control Options for NO_X:

1. Exhaust Gas Recirculation: Page 70 of the Alternative Control Techniques Document for Stationary Diesel Engines discusses the expected costs of exhaust gas recirculation. A cost of between $500 to $700 to retrofit an engine with exhaust gas recirculation technology was mentioned (Bradley Nelson, 2010). For an average of 37.5% control efficiency, this could result in a 0.09 tpy NO_X reduction to a 0.37 tpy NO_X reduction depending on the size of the engine. Due to the tendencies for exhaust gas recirculation to foul air intake systems, cause combustion chamber deposits, and increase engine wear rates on stationary diesel engines, the use of this control option would potentially increase operating and maintenance costs for engines. Therefore, on a site-by-site basis, this could be considered cost-effective for NO_X control. Because this is considered the top feasible control option for NO_X control, the remaining NO_X control options discussed in the above sections have not been evaluated.

Control Options for SO_2:

1. Ultra-Low Sulfur Diesel Fuel: Ultra-low sulfur diesel fuel is a standard requirement in 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for newer and certain existing stationary engines. The DAQ has also incorporated these sulfur requirements into many existing permits. The Alternative Control Techniques Document for Stationary Diesel Engines discusses a cost difference of up to $0.20 per gallon between ULSD fuel and high sulfur diesel fuel (Bradley Nelson, 2010). However, due to the fact of ULSD fuel becoming widely-adopted, this is considered a cost-effective technology.

Control Options for VOC:

1. Catalyzed Diesel Particulate Filter: Based on Table 5-5 on page 63 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of THC removed varies from $26,061 to $166,959. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of THC removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.
2. Diesel Oxidation Catalyst: Based on Table 5-8 on page 67 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of THC removed varies from $4,687 to $37,061. The costs in this table were

based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines. Therefore, the cost/ton of THC removed would be higher for an emergency stationary diesel engine. This control option could potentially be cost-effective for this category; however, because most emergency stationary diesel engines operate less than prime stationary diesel engines (which were assumed to operate for 1,000 hours for the cost estimate in Table 5-8), the cost/ton of THC removed is probably closer to $23,435 to $185,305. More information would be needed on a site-by-site basis to determine if this was a cost-effective solution to limit VOC emissions from an emergency stationary diesel engine.

8A.7 - Evaluation of Findings & Control Selection:

Control Options for $PM_{2.5}$: The DAQ did not find any $PM_{2.5}$ controls that were cost effective for controlling $PM_{2.5}$ emissions. Therefore, BACT for direct $PM_{2.5}$ emissions is proper maintenance and operation of the emergency stationary diesel engine.

Control Options for NO_X: The installation of a new emergency stationary diesel engine subject to the newest requirements for stationary emergency engines as specified in 40 CFR 60 Subpart IIII could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart IIII. This control selection is not applicable to newer engines. In the absence of replacing an old engine with a new engine, the installation of exhaust gas recirculation technology on older engines could be cost effective and feasible, again depending on a site-by-site basis of actual cost to retrofit the stationary emergency diesel engine on site. This control selection is assuming an old engine that is not currently subject to 40 CFR 60 Subpart IIII.

Control Options for SO_2: The DAQ recommends the use of ultra-low sulfur diesel fuel as BACT for SO_2 control.

Control Options for VOC: The DAQ did not find any VOC controls that were cost effective for controlling VOC emissions. Depending on the age of the engine and site-specific information, a diesel oxidation catalyst could be cost effective for controlling VOC emissions. However, the DAQ does not recommend a diesel oxidation catalyst as BACT for this source category due to the fact this control option is probably not cost effective. Therefore, the DAQ recommends proper maintenance and operation of the emergency stationary diesel engine as BACT for control of VOC emissions. A site-specific cost/ton removed could be derived for making a determination on the requirement of installing a diesel oxidation catalyst.

8A.8 - Time for Implementation:

The DAQ recommends 90 days to implement the usage of ultra-low sulfur diesel fuel if a source is not already using it, 180 days to retrofit an engine with exhaust gas recirculation technology if a source is not already using it, and up to 1 year to replace an existing stationary emergency diesel engine with a new stationary emergency diesel engine.

8B. - Diesel-Fired Emergency Generators 200-600 hp

8B.1 - Description:

This source category is emergency engines that are moderately sized, rated greater than or equal to 200 hp and less than 600 hp. This source category can be found in any kind of industrial, commercial, or institutional setting. Emergency engines are typically used to provide power for sources in emergency situations, when electric power from the public utilities is interrupted. Emergency engines are also typically operated weekly or monthly at zero or low loads for regular maintenance and testing to ensure proper engine operations.

8B.2 - Emissions Summary:

This source category could represent a variety of different engines with different sizes and ages. The emissions from these engines vary greatly. To be conservative, base emissions were calculated assuming an older engine, not subject to the standards in 40 CFR 60 Subpart IIII. Emissions were calculated for the following engine sizes: 290, 400, 500, and 600 hp. Emission estimates used emission factors from AP-42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1 (AP-42) was used for all emission factors (United States Environmental Protection Agency, 1996a, p. 3).

This source category is capable of emitting direct $PM_{2.5}$, and the following $PM_{2.5}$ precursor pollutants: SO_2, NO_X, and VOC. To determine direct $PM_{2.5}$ from AP-42 emission factors, the CEIDARS List with $PM_{2.5}$ fractions for Internal Combustion – Distillate and Diesel-Except Electric Generation $PM_{2.5}$ Fraction of PM_{10} of 0.991 was used (Mike Krause & Steve Smith, Ph.D., 2006). Based on an EPA guidance memorandum from John S. Seitz to Region Directors (John S. Seitz, 1995), and a response to William O'Sullivan, Director of the New Jersey Division of Air Quality, from EPA Region 2 Chief of the Permitting Section Steven C. Riva (Steven C. Riva, 2006), a total of 200 operating hours per year was used to calculate the PTE for this source category. The 200 operating hours will adequately cover the time when the emergency engine is used for maintenance, testing, and emergency situations.

8B.3 - Control Options:

The following sources were reviewed to identify available control technologies:

- EPA's RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA's Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state regulations
- 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
- Various state-specific example permits
- A thorough literature search using the Google search engine

After a review of the above sources, the DAQ determined that many state and federal regulations provide specific exemptions for the control and applicability of various regulations and control devices to emergency engines. The following control options were found for controlling emissions from stationary diesel engines:

Control Options for $PM_{2.5}$:

- Catalyzed Diesel Particulate Filter (CleanAIR Systems, 2009)
- Diesel Oxidation Catalyst (CS, 2009)
- Diesel Particulate Filter (CS, 2009)

Control Options for NO_X:

- Exhaust Gas Recirculation (CS, 2009)
- NO_X Adsorber Catalyst (CS, 2009)
- Selective Catalytic Reduction (CS, 2009)
- Turbocharging and aftercooling (US EPA, 1993)
- Engine Ignition Timing Retardation (US EPA, 1993)
- Modifying air-to-fuel ratio (US EPA, 1993)

Control Options for SO_2:

- Ultra-Low Sulfur Diesel Fuel (Bradley Nelson, 2010)

Control Options for VOC:

- Catalyzed Diesel Particulate Filter (CS, 2009)
- Diesel Oxidation Catalyst (CS, 2009)

Additional control options for all pollutants include replacement of older engines with new engines, and adherence to emission limitations contained in 40 CFR 60 Subpart IIII. 40 CFR 63 Subpart ZZZZ contains no additional requirements for emergency engines beyond operational and maintenance practices. For older engines that do not comply with an emission limitation in 40 CFR 60 Subpart IIII, emissions could be controlled by one of the above methods.

8B.4 - <u>Technological Feasibility:</u>

Many of the above control options are possible control options for stationary diesel engines used for prime operations, rather than emergency operations. Due to the unique operating scenario of emergency diesel engines, several of the technologies are not technically feasible.

Control Options for $PM_{2.5}$:

Catalyzed Diesel Particulate Filter

This control technology has been approved under the California Air Resources Board's (CARB) verification procedure for emergency engines (California Air Resources Board, 2017). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Oxidation Catalyst

Miratech supplies a CARB Level 3 Plus Verified diesel oxidation catalyst in series with a diesel particulate filter designed for use with emergency backup generator units ("LTR Diesel Oxidation Catalyst," n.d.). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Particulate Filter

CARB has concluded that diesel particulate filters are technologically feasible with some additional operational and monitoring conditions (Matt Baldwin, 2016). Drawbacks exist for the

use of diesel particulate filters for emergency engines. If an engine is run at a low load, the filter may clog quickly and the engine would need to be run at a higher load to clear the filter. Therefore, the total PM controlled by the filter will most likely be less than the NO_X emitted from running at the higher load. According to case studies, multiple sources have successfully installed diesel particulate filters on emergency diesel engines with minimal problems (Manufacturers of Emission Controls Association, 2009). Therefore, this is a technically feasible control option for emergency diesel engines.

Control Options for NO_X:

Exhaust Gas Recirculation

Exhaust gas recirculation is typically incorporated in new stationary diesel engines automatically. Exhaust gas recirculation can result in fouled air intake systems, combustion chamber deposits, and increased engine wear rates on stationary diesel engines, but is feasible (US EPA, 1993). Therefore, this is a technically feasible control option for new emergency diesel engines. Some exhaust gas recirculation technologies can also be retrofitted to older engines (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency diesel engines.

NO_X Adsorber Catalyst

This is an emerging control technology that has been approved for on-road diesel engines and is currently being researched for adaptation for controlling stationary diesel engines. There are no real-world examples of this control technology being used to control emissions from stationary diesel emergency engines (Bradley Nelson, 2010). Therefore, this is not a technically feasible control option for stationary emergency diesel engines.

Selective Catalytic Reduction

CARB has determined that selective catalytic reduction, while technologically feasible in some cases, has challenges when applying it to emergency diesel engines. Emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine (Matt Baldwin, 2016). This could also be a challenge for many emergency engine applications. Therefore, this is not a technically feasible control option for stationary emergency diesel engines.

Turbocharging and aftercooling

Turbocharging and aftercooling is typically incorporated in new stationary diesel engines automatically. Therefore, this is a technically feasible control option for new emergency diesel engines. Existing emergency engines can be modified to be equipped with a turbocharger (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency diesel engines.

Engine Ignition Timing Retardation

Ignition timing can be adjusted on new and existing diesel engines; however, an electronic injection control system is needed to ensure sustained NO_X emissions reductions (US EPA, 1993). Most new engines have electronic injection control systems automatically installed;

therefore, this is a technically feasible option for new emergency diesel engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency diesel engines.

Modifying air-to-fuel ratio
New emergency diesel engines have electronic injection control systems automatically installed that can modify the air-to-fuel ratio to ensure a lean burn scenario. Therefore, this is a technically feasible option for new emergency diesel engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency diesel engines.

Control Options for SO_2:
Ultra-Low Sulfur Diesel Fuel
Ultra-low sulfur diesel fuel is a standard requirement in 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for newer and certain existing stationary engines. The DAQ has also incorporated these sulfur requirements into many existing permits. Therefore, this is a technically feasible control option.

Control Options for VOC:
Catalyzed Diesel Particulate Filter
This control technology has been approved under CARB's verification procedure for emergency engines (California Air Resources Board, 2017). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Oxidation Catalyst
Miratech supplies a CARB Level 3 Plus Verified diesel oxidation catalyst in series with a diesel particulate filter designed for use with emergency backup generator units ("LTR Diesel Oxidation Catalyst," n.d.). Therefore, this is a technically feasible control option for emergency diesel engines.

8B.5 - Ranking of Individual and Combined Controls:

Control Options for $PM_{2.5}$:

1. Catalyzed Diesel Particulate Filter: 85% - 90% (case dependent) (Bradley Nelson, 2010)
2. Diesel Particulate Filter: 85% – 90% control efficiency (case dependent) (Bradley Nelson, 2010)
3. Diesel Oxidation Catalyst: 20% - 50% control efficiency (Bradley Nelson, 2010)

Control Options for NO_X:

1. Exhaust Gas Recirculation: 25% - 50% control efficiency (Bradley Nelson, 2010)
2. Engine Ignition Timing Retardation & Modifying air-to-fuel ratio: 2.7% - 48% control efficiency (Eric Patton, P.E., 1998)
3. Engine Ignition Timing Retardation: 20% - 45% control efficiency (US EPA, 1996b, p. 4)
4. Turbocharging and aftercooling: 3% - 35% control efficiency (Eric Patton, P.E., 1998)
5. Modifying air-to-fuel ratio: 7% - 8% control efficiency (US EPA, 1996b, p. 4)

Control Options for SO_2:

1. Ultra-Low Sulfur Diesel Fuel: 5% - 30% reduction in SO_2 (Bradley Nelson, 2010)

Control Options for VOC:

1. Catalyzed Diesel Particulate Filter: 90% control efficiency (Bradley Nelson, 2010)
2. Diesel Oxidation Catalyst: 90% control efficiency (Bradley Nelson, 2010)

8B.6 - Economic Feasibility:

The cost of purchasing a new diesel engine subject to Tier 2 or Tier 3 standards can range from $10,000 for a 100 hp engine to $180,000 for a 1,500 hp diesel engine (Bradley Nelson, 2010).

For a 400 hp engine, the difference of emissions of an existing engine and a new engine is as follows:

- 0.077 tpy of $PM_{2.5}$
- 0.97 tpy of NO_X

The following assumptions were used in this analysis:

- The Engine Size is 400 hp
- The cost of a 400 hp engine is $40,000
- An annual interest rate of 7% (US EPA, 2002)
- The economic life of each engine is 20 years
- Negligible annual maintenance costs due to costs most likely being similar to current costs with an existing engine

Based on these assumptions, the cost/ton removed for replacing an existing engine with a new engine is as follows:

- $38,130 for $PM_{2.5}$
- $3,274 for NO_X

Based on the cost above for $PM_{2.5}$ control, it is not cost effective to purchase a new engine subject to the most stringent Tier 3 standards specified in 40 CFR 60 Subpart IIII. However, based on the cost above for NO_X control, it could potentially be cost effective to purchase a new engine subject to the newest Tier 3 standards for emergency engines in this size source category as specified in 40 CFR 60 Subpart IIII.

Control Options for $PM_{2.5}$:

1. Catalyzed Diesel Particulate Filter: Based on Table 5-3 on page 61 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $44,180 to $134,461. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.
2. Diesel Particulate Filter: Based on Table 5-3 on page 61 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $44,180 to $134,461. The costs in this table were

based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines. Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine (Bradley Nelson, 2010). This control option is not cost-effective for this category.

3. Diesel Oxidation Catalyst: Based on Table 5-6 on page 65 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from \$55,952 to \$161,159. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.

Control Options for NO_X:

1. Exhaust Gas Recirculation: Page 70 of the Alternative Control Techniques Document for Stationary Diesel Engines discusses the expected costs of exhaust gas recirculation. A cost of between \$500 to \$700 to retrofit an engine with exhaust gas recirculation technology was mentioned (Bradley Nelson, 2010). For an average of 37.5% control efficiency, this could result in a 0.56 tpy NO_X reduction to a 1.16 tpy NO_X reduction depending on the size of the engine. Due to the tendencies for exhaust gas recirculation to foul air intake systems, cause combustion chamber deposits, and increase engine wear rates on stationary diesel engines, the use of this control option would potentially increase operating and maintenance costs for engines. Therefore, on a site-by-site basis, this could be considered cost-effective for NO_X control, if the engine does not already have this technology. Because this is considered the top feasible control option for NO_X control, the remaining NO_X control options discussed in the above sections have not been evaluated.

Control Options for SO_2:

1. Ultra-Low Sulfur Diesel Fuel: Ultra-low sulfur diesel fuel is a standard requirement in 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for newer and certain existing stationary engines. The DAQ has also incorporated these sulfur requirements into many existing permits. The Alternative Control Techniques Document for Stationary Diesel Engines discusses a cost difference of up to \$0.20 per gallon between ULSD fuel and high sulfur diesel fuel (Bradley Nelson, 2010). However, due to the fact of ULSD fuel becoming widely-adopted, this is considered a cost-effective technology.

Control Options for VOC:

1. Catalyzed Diesel Particulate Filter: Based on Table 5-5 on page 63 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of THC removed varies from \$26,061 to \$96,243. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of THC removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.
2. Diesel Oxidation Catalyst: Based on Table 5-8 on page 67 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical

cost/ton of THC removed varies from $4,687 to $17,404. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines. Therefore, the cost/ton of THC removed would be higher for an emergency stationary diesel engine. This control option could potentially be cost-effective for this category; however, because most emergency stationary diesel engines operate less than prime stationary diesel engines (which were assumed to operate for 1,000 hours for the cost estimate in Table 5-8), the cost/ton of THC removed is probably closer to $23,435 to $87,020. More information would be needed on a site-by-site basis to determine if this was a cost-effective solution to limit VOC emissions from an emergency stationary diesel engine.

8B.7 - Evaluation of Findings & Control Selection:

Control Options for $PM_{2.5}$: The DAQ did not find any $PM_{2.5}$ controls that were cost effective for controlling $PM_{2.5}$ emissions. Therefore, BACT for direct $PM_{2.5}$ emissions is proper maintenance and operation of the emergency stationary diesel engine.

Control Options for NO_X: The installation of a new emergency stationary diesel engine subject to the newest requirements for stationary emergency engines as specified in 40 CFR 60 Subpart IIII could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart IIII.

In the absence of replacing an old engine with a new engine, the installation of exhaust gas recirculation technology on older engines could be cost effective and feasible, depending on a site-by-site basis of actual cost to retrofit the stationary emergency diesel engine on site. This control selection is assuming that an old engine is not currently subject to 40 CFR 60 Subpart IIII.

Control Options for SO_2: The DAQ recommends the use of ultra-low sulfur diesel fuel as BACT for SO_2 control.

Control Options for VOC: The DAQ did not find any VOC controls that were cost effective for controlling VOC emissions. Depending on the age of the engine and site-specific information, a diesel oxidation catalyst could be cost effective for controlling VOC emissions. However, the DAQ does not recommend a diesel oxidation catalyst as BACT for this source category due to the fact that this control option is probably not cost effective. Therefore, the DAQ recommends proper maintenance and operation of the emergency stationary diesel engine as BACT for control of VOC emissions. A site-specific cost/ton removed analysis should be performed to determine the requirement of installing a diesel oxidation catalyst.

8B.8 - Time for Implementation:

The DAQ recommends 90 days to implement the usage of ultra-low sulfur diesel fuel if a source is not already using it, 180 days to retrofit an engine with exhaust gas recirculation technology if a source is not already using it, and up to 1 year to replace an existing stationary emergency diesel engine with a new stationary emergency diesel engine.

8C. - Diesel-Fired Emergency Generators >600 hp

8C.1 - Description:

This source category is emergency engines that are large, rated greater than 600 hp. This source category can be found in any kind of industrial, commercial, or institutional setting. Emergency engines are typically used to provide power for sources in emergency situations, when electric power from the public utilities is interrupted. Emergency engines are also typically operated weekly or monthly at zero or low loads for regular maintenance and testing to ensure proper engine operations.

8C.2 - Emissions Summary:

This source category could represent a variety of different engines with different sizes and ages. The emissions from these engines vary greatly. To be conservative, base emissions were calculated assuming an older engine, not subject to the standards in 40 CFR 60 Subpart IIII. Emissions were calculated for the following engine sizes: 800, 1,000, 1,200, and 1,400 hp. Emission estimates used emission factors from AP-42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1 (United States Environmental Protection Agency, 1996, p. 4).

This source category is capable of emitting direct $PM_{2.5}$, and the following $PM_{2.5}$ precursor pollutants: SO_2, NO_X, and VOC. To determine direct $PM_{2.5}$ from AP-42 emission factors, the CEIDARS List with $PM_{2.5}$ fractions for Internal Combustion – Distillate and Diesel-Except Electric Generation $PM_{2.5}$ Fraction of PM_{10} of 0.991 was used (Mike Krause & Steve Smith, Ph.D., 2006). Based on an EPA guidance memorandum from John S. Seitz to Region Directors (John S. Seitz, 1995), and a response to William O'Sullivan, Director of the New Jersey Division of Air Quality, from EPA Region 2 Chief of the Permitting Section Steven C. Riva (Steven C. Riva, 2006), a total of 200 operating hours per year was used to calculate the PTE for this source category. The 200 operating hours will adequately cover the time when the emergency engine is used for maintenance, testing, and emergency situations.

8C.3 - Control Options:

The following sources were reviewed to identify available control technologies:

- EPA's RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA's Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state regulations
- 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
- Various state-specific example permits
- A thorough literature search using the Google search engine

After a review of the above sources, the DAQ determined that many state and federal regulations provide specific exemptions for the control and applicability of various regulations and control devices to emergency engines. The following control options were found for controlling emissions from stationary diesel engines:

Control Options for $PM_{2.5}$:

- Catalyzed Diesel Particulate Filter (CleanAIR Systems, 2009)
- Diesel Oxidation Catalyst (CS, 2009)
- Diesel Particulate Filter (CS, 2009)

Control Options for NO_X:

- Exhaust Gas Recirculation (CS, 2009)
- NO_X Adsorber Catalyst (CS, 2009)
- Selective Catalytic Reduction (CS, 2009)
- Turbocharging and aftercooling (US EPA, 1993)
- Engine Ignition Timing Retardation (US EPA, 1993)
- Modifying air-to-fuel ratio (US EPA, 1993)

Control Options for SO_2:

- Ultra-Low Sulfur Diesel Fuel (Bradley Nelson, 2010)

Control Options for VOC:

- Catalyzed Diesel Particulate Filter (CS, 2009)
- Diesel Oxidation Catalyst (CS, 2009)

Additional control options for all pollutants include replacement of older engines with new engines, and adherence to emission limitations contained in 40 CFR 60 Subpart IIII. 40 CFR 63 Subpart ZZZZ contains no additional requirements for emergency engines beyond operational and maintenance practices. For older engines that do not comply with an emission limitation in 40 CFR 60 Subpart IIII, emissions could be controlled by one of the above methods.

8C.4 - Technological Feasibility:

Many of the above control options are possible control options for stationary diesel engines used for prime operations, rather than emergency operations. Due to the unique operating scenario of emergency diesel engines, several of the technologies are not technically feasible.

Control Options for $PM_{2.5}$:

Catalyzed Diesel Particulate Filter

This control technology has been approved under the California Air Resources Board's (CARB) verification procedure for emergency engines (California Air Resources Board, 2017). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Oxidation Catalyst

Miratech supplies a CARB Level 3 Plus Verified diesel oxidation catalyst in series with a diesel particulate filter designed for use with emergency backup generator units ("LTR Diesel Oxidation Catalyst," n.d.). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Particulate Filter

CARB has concluded that diesel particulate filters are technologically feasible with some additional operational and monitoring conditions (Matt Baldwin, 2016). Drawbacks exist for the

use of diesel particulate filters for emergency engines. If an engine is run at a low load, the filter may clog quickly and the engine would need to be run at a higher load to clear the filter. Therefore, the total PM controlled by the filter will most likely be less than the NO_X emitted from running at the higher load. According to case studies, multiple sources have successfully installed diesel particulate filters on emergency diesel engines with minimal problems (Manufacturers of Emission Controls Association, 2009). Therefore, this is a technically feasible control option for emergency diesel engines.

Control Options for NO_X:

Exhaust Gas Recirculation

Exhaust gas recirculation is typically incorporated in new stationary diesel engines automatically. Exhaust gas recirculation can result in fouled air intake systems, combustion chamber deposits, and increased engine wear rates on stationary diesel engines, but is feasible (US EPA, 1993). Therefore, this is a technically feasible control option for new emergency diesel engines. Some exhaust gas recirculation technologies can also be retrofitted to older engines (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency diesel engines.

NO_X Adsorber Catalyst

This is an emerging control technology that has been approved for on-road diesel engines and is currently being researched for adaptation for controlling stationary diesel engines. There are no real-world examples of this control technology being used to control emissions from stationary diesel emergency engines (Bradley Nelson, 2010). Therefore, this is not a technically feasible control option for stationary emergency diesel engines.

Selective Catalytic Reduction

CARB has determined that selective catalytic reduction, while technologically feasible in some cases, has challenges when applying it to emergency diesel engines. Emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine (Matt Baldwin, 2016). This could also be a challenge for many emergency engine applications. Therefore, this is not a technically feasible control option for stationary emergency diesel engines.

Turbocharging and aftercooling

Turbocharging and aftercooling is typically incorporated in new stationary diesel engines automatically. Therefore, this is a technically feasible control option for new emergency diesel engines. Existing emergency engines can be modified to be equipped with a turbocharger (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency diesel engines.

Engine Ignition Timing Retardation

Ignition timing can be adjusted on new and existing diesel engines; however, an electronic injection control system is needed to ensure sustained NO_X emissions reductions (US EPA, 1993). Most new engines have electronic injection control systems automatically installed;

therefore, this is a technically feasible option for new emergency diesel engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency diesel engines.

Modifying air-to-fuel ratio
New emergency diesel engines have electronic injection control systems automatically installed that can modify the air-to-fuel ratio to ensure a lean burn scenario. Therefore, this is a technically feasible option for new emergency diesel engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency diesel engines.

Control Options for SO_2:
Ultra-Low Sulfur Diesel Fuel
Ultra-low sulfur diesel fuel is a standard requirement in 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for newer and certain existing stationary engines. The DAQ has also incorporated these sulfur requirements into many existing permits. Therefore, this is a technically feasible control option.

Control Options for VOC:
Catalyzed Diesel Particulate Filter
This control technology has been approved under CARB's verification procedure for emergency engines (California Air Resources Board, 2017). Therefore, this is a technically feasible control option for emergency diesel engines.

Diesel Oxidation Catalyst
Miratech supplies a CARB Level 3 Plus Verified diesel oxidation catalyst in series with a diesel particulate filter designed for use with emergency backup generator units ("LTR Diesel Oxidation Catalyst," n.d.). Therefore, this is a technically feasible control option for emergency diesel engines.

8C.5 - <u>Ranking of Individual and Combined Controls:</u>

Control Options for $PM_{2.5}$:

1. Catalyzed Diesel Particulate Filter: 85% - 90% (case dependent) (Bradley Nelson, 2010)
2. Diesel Particulate Filter: 85% – 90% control efficiency (case dependent) (Bradley Nelson, 2010)
3. Diesel Oxidation Catalyst: 20% - 50% control efficiency (Bradley Nelson, 2010)

Control Options for NO_X:

1. Exhaust Gas Recirculation: 25% - 50% control efficiency (Bradley Nelson, 2010)
2. Engine Ignition Timing Retardation & Modifying air-to-fuel ratio: 2.7% - 48% control efficiency (Eric Patton, P.E., 1998)
3. Engine Ignition Timing Retardation: 20% - 45% control efficiency (US EPA, 1996, p. 4)
4. Turbocharging and aftercooling: 3% - 35% control efficiency (Eric Patton, P.E., 1998)
5. Modifying air-to-fuel ratio: 7% - 8% control efficiency (US EPA, 1996, p. 4)

Control Options for SO_2:

1. Ultra-Low Sulfur Diesel Fuel: 5% - 30% reduction in SO_2 (Bradley Nelson, 2010)

Control Options for VOC:

1. Catalyzed Diesel Particulate Filter: 90% control efficiency (Bradley Nelson, 2010)
2. Diesel Oxidation Catalyst: 90% control efficiency (Bradley Nelson, 2010)

8C.6 - <u>Economic Feasibility:</u>

1. Catalyzed Diesel Particulate Filter: Based on Table 5-3 on Page 61of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $32,641 to $104,914. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.
2. Diesel Particulate Filter: Based on Table 5-3 on Page 61of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $32,641 to $104,914. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.
3. Diesel Oxidation Catalyst: Based on Table 5-6 on Page 65of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of PM removed varies from $41,159 to $131,018. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of PM removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.

Control Options for NO_X:

1. Exhaust Gas Recirculation: Page 70 of the Alternative Control Techniques Document for Stationary Diesel Engines discusses the expected costs of exhaust gas recirculation. A cost of between $500 to $700 to retrofit an engine with exhaust gas recirculation technology was mentioned (Bradley Nelson, 2010). For an average of 37.5% control efficiency, this could result in a 1.40 tpy NO_X reduction to a 1.96 tpy NO_X reduction depending on the size of the engine. Due to the tendencies for exhaust gas recirculation to foul air intake systems, cause combustion chamber deposits, and increase engine wear rates on stationary diesel engines, the use of this control option would potentially increase operating and maintenance costs for engines. Therefore, on a site-by-site basis, this could be considered cost-effective for NO_X control, if the engine does not already have this technology. Because this is considered the top feasible control option for NO_X control, the remaining NO_X control options discussed in the above sections have not been evaluated.

Control Options for SO_2:

1. Ultra-Low Sulfur Diesel Fuel: Ultra-low sulfur diesel fuel is a standard requirement in 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for newer and certain existing stationary engines. The DAQ has also incorporated these sulfur requirements into many existing permits. The Alternative Control Techniques Document for Stationary Diesel Engines discusses a cost difference of up to $0.20 per gallon between ULSD fuel and high sulfur diesel fuel (Bradley Nelson, 2010). However, due to the fact of ULSD fuel becoming widely-adopted, this is considered a cost-effective technology.

Control Options for VOC:

1. Catalyzed Diesel Particulate Filter: Based on Table 5-5 on Page 63 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of THC removed varies from $19,280 to $93,374. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines (Bradley Nelson, 2010). Therefore, the cost/ton of THC removed would be higher for an emergency stationary diesel engine. This control option is not cost-effective for this category.
2. Diesel Oxidation Catalyst: Based on Table 5-8 on Page 67 of the Alternative Control Techniques Document for Stationary Diesel Engines, for this size engine, the typical cost/ton of THC removed varies from $2,834 to $14,333. The costs in this table were based on 2005 dollars and prime stationary diesel engines, which operate more throughout the year than emergency stationary diesel engines. Therefore, the cost/ton of THC removed would be higher for an emergency stationary diesel engine. This control option could potentially be cost-effective for this category; however, because most emergency stationary diesel engines operate less than prime stationary diesel engines (which were assumed to operate for 1,000 hours for the cost estimate in Table 5-8), the cost/ton of THC removed is probably closer to $14,170 to $71,665. More information would be needed on a site-by-site basis to determine if this was a cost-effective solution to limit VOC emissions from an emergency stationary diesel engine.

8C.7 - <u>Evaluation of Findings & Control Selection:</u>

Control Options for $PM_{2.5}$: The DAQ did not find any $PM_{2.5}$ controls that were cost effective for controlling $PM_{2.5}$ emissions. Therefore, BACT for direct $PM_{2.5}$ emissions is proper maintenance and operation of the emergency stationary diesel engine.

Control Options for NO_X: The installation of a new emergency stationary diesel engine subject to the newest requirements for stationary emergency engines as specified in 40 CFR 60 Subpart IIII could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart IIII. This control selection is not applicable to newer engines. In the absence of replacing an old engine with a new engine, the installation of exhaust gas recirculation technology on older engines could be cost effective and feasible, again depending on a site-by-site basis of actual cost to retrofit the stationary emergency diesel engine on site. This control selection is assuming an old engine that is not currently subject to 40 CFR 60 Subpart IIII.

Control Options for SO_2: The DAQ recommends the use of ultra-low sulfur diesel fuel as BACT for SO_2 control.

Control Options for VOC: The DAQ did not find any VOC controls that were cost effective for controlling VOC emissions. Depending on the age of the engine and site-specific information, a diesel oxidation catalyst could be cost effective for controlling VOC emissions. However, the DAQ does not recommend a diesel oxidation catalyst as BACT for this source category due to the fact this control option is probably not cost effective. Therefore, the DAQ recommends proper maintenance and operation of the emergency stationary diesel engine as BACT for the control of VOC emissions. A site-specific cost/ton removed could be derived for making a determination on the requirement of installing a diesel oxidation catalyst.

8C.8 - Time for Implementation:

The DAQ recommends 90 days to implement the usage of ultra-low sulfur diesel fuel if a source is not already using it and 180 days to retrofit an engine with exhaust gas recirculation technology if a source is not already using it.

8D. - Natural Gas-Fired Emergency Generators <500 hp

8D.1 - Description:

This source category is for emergency engines that are moderately sized to small, rated less than 500 hp. This source category can be found in any kind of industrial, commercial, or institutional setting. Emergency engines are typically used to provide power for sources in emergency situations, when electric power from the public utilities is interrupted. Emergency engines are also typically operated weekly or monthly at zero or low loads for regular maintenance and testing to ensure proper engine operations.

8D.2 - Emissions Summary:

This source category could represent a variety of different engines with different sizes and ages. The emissions from these engines vary greatly. To be conservative, base emissions were calculated assuming an older engine, not subject to the standards in 40 CFR 60 Subpart JJJJ. Emissions were calculated for the following engine sizes: 50, 100, 200, 300, 400, and 500 hp. Emission estimates used emission factors from AP-42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1 (United States Environmental Protection Agency, 2000, p. 2).

This source category can emit direct $PM_{2.5}$, and the following $PM_{2.5}$ precursor pollutants: SO_2, NO_x, and VOC. SO_2 emissions from natural gas-fired engines are minimal. To determine direct $PM_{2.5}$ from AP-42 emission factors, the CEIDARS List with PM2.5 fractions for Internal Combustion – Gaseous Fuel PM2.5 Fraction of PM10 of 0.998 was used (Mike Krause & Steve Smith, Ph.D., 2006). Based on an EPA guidance memorandum from John S. Seitz to Region Directors (John S. Seitz, 1995), and a response to William O'Sullivan, Director of the New Jersey Division of Air Quality, from EPA Region 2 Chief of the Permitting Section Steven C. Riva (Steven C. Riva, 2006), a total of 200 operating hours per year was used to calculate the PTE for this source category. The 200 operating hours will adequately cover the time when the emergency engine is used for maintenance, testing, and emergency situations.

8D.3 - Control Options:

The following sources were reviewed to identify available control technologies:

- EPA's RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA's Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state regulations
- 40 CFR 60 Subpart JJJJ and 40 CFR 63 Subpart ZZZZ
- Various state-specific example permits
- A thorough literature search using the Google search engine

After a review of the above sources, the DAQ determined that many state and federal regulations provide specific exemptions for the control and applicability of various regulations and control devices to emergency engines. The following control options were found for controlling emissions from stationary natural gas-fired engines:

Control Options for NO_x:

- Non-Selective Catalytic Reduction (for rich-burn engines with carburetors) (CleanAIR Systems, 2009)
- Exhaust Gas Recirculation (CS, 2009)
- Lean NOx Catalyst (for lean-burn engines) (CS, 2009)
- Selective Catalytic Reduction (for lean-burn engines) (CS, 2009)
- Turbocharging and aftercooling (US EPA, 1993)
- Engine Ignition Timing Retardation (US EPA, 1993)
- Modifying air-to-fuel ratio (US EPA, 1993)

Control Options for VOC:

- Non-Selective Catalytic Reduction (for rich-burn engines) (CS, 2009)
- Oxidation Catalyst (for lean-burn engines) (CS, 2009)

Additional control options for all pollutants include replacement of older engines with new engines, and adherence to emission limitations contained in 40 CFR 60 Subpart JJJJ. 40 CFR 63 Subpart ZZZZ contains no additional requirements for emergency engines beyond operational and maintenance practices. For older engines that do not comply with an emission limitation in 40 CFR 60 Subpart JJJJ, emissions could be controlled by one of the above methods.

8D.4 - <u>Technological Feasibility:</u>

Many of the above control options are possible control options for stationary SI engines used for prime operations, rather than emergency operations. Therefore, several of the technologies are technically infeasible due to the unique operating scenario of emergency SI engines.

Control Options for NO_x:

Non-Selective Catalytic Reduction (for rich-burn engines with carburetors)

Non-selective catalytic reduction techniques are difficult on engines with variable engine load (US EPA, 1993). In addition, emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate optimally. The engine would then need to be operated at higher loads for longer periods, fundamentally changing the operation of the emergency engine. This could also be a challenge for many emergency engine applications. However, according to the Washington Department of Ecology Document "Suitability of Spark Ignition, Gaseous Fossil Fuel-Powered Emergency Generators for Air Quality General Order of Approval", Page 10, non-selective catalytic reduction was chosen as BACT for rich-burn emergency engines (Washington State Department of Ecology, n.d.). Therefore, this is a technically feasible control option for stationary emergency SI engines.

Exhaust Gas Recirculation

Exhaust gas recirculation is typically incorporated in new stationary SI engines automatically. Therefore, this is a technically feasible control option for new emergency SI engines. Some exhaust gas recirculation technologies can also be retrofitted to older engines (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency SI engines.

Lean NO_x Catalyst (for lean-burn engines)
Lean NO_x catalysts are a new technology that has demonstrated NO_x emission reductions. The catalyst operates at a narrow temperature range, from 392 °F to 842 °F depending on the catalyst formulation (Manufacturers of Emission Controls Association, 2015). Emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine. This could also be a challenge for many emergency engine applications. Therefore, this is not a technically feasible control option for stationary emergency engines, including SI engines.

Selective Catalytic Reduction (for lean-burn engines)
The California Air Resources Board (CARB) has determined that selective catalytic reduction, while technologically feasible in some cases, has challenges when applying it to emergency engines. Emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine (Matt Baldwin, 2016). This could also be a challenge for many emergency engine applications. Therefore, this is not a technically feasible control option for stationary emergency engines, including SI engines.

Turbocharging and aftercooling
Turbocharging and aftercooling is typically incorporated in new stationary SI engines automatically. Therefore, this is a technically feasible control option for new emergency SI engines. Existing emergency engines can be modified to be equipped with a turbocharger (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency SI engines.

Engine Ignition Timing Retardation
Ignition timing can be adjusted on new and existing SI engines; however, an electronic injection control system is needed to ensure sustained NOx emissions reductions (US EPA, 1993). Most new engines have electronic injection control systems automatically installed; therefore, this is a technically feasible option for new emergency SI engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency SI engines.

Modifying air-to-fuel ratio
New emergency SI engines have electronic injection control systems automatically installed that can modify the air-to-fuel ratio to ensure a lean burn scenario. Therefore, this is a technically feasible option for new emergency SI engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency SI engines.

Control Options for VOC:

Non-Selective Catalytic Reduction (for rich-burn engines with carburetors)

Non-selective catalytic reduction techniques are difficult on engines with variable engine load (US EPA, 1993). In addition, emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to optimally operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine. This could also be a challenge for many emergency engine applications. However, according to the Washington Department of Ecology Document "Suitability of Spark Ignition, Gaseous Fossil Fuel-Powered Emergency Generators for Air Quality General Order of Approval", Page 10, non-selective catalytic reduction was chosen as BACT for rich-burn emergency engines (Washington State Department of Ecology, n.d.). Therefore, this is a technically feasible control option for stationary emergency SI engines.

Oxidation Catalyst (for lean-burn engines)

Oxidation catalysts are frequently installed on lean-burn engines to control VOC emissions; therefore, this is a technically feasible control option for stationary emergency SI engines (Manufacturers of Emission Controls Association, 2015).

8D.5 - Ranking of Individual and Combined Controls:

Control Options for NOx:

1. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): 90% - 98% control efficiency (US EPA, 1993)
2. Turbocharging and aftercooling: 87% control efficiency (Considered part of L-E retrofitting) (US EPA, 1993)
3. Exhaust Gas Recirculation: 25% - 50% control efficiency (Alternative Control Techniques Document: Stationary Diesel Engines – similar control efficiency assumed for SI engines) (Bradley Nelson, 2010)
4. Engine Ignition Timing Retardation & Modifying air-to-fuel ratio: 10% - 40% control efficiency (US EPA, 1993)
5. Modifying air-to-fuel ratio: 5% - 40% control efficiency (US EPA, 1993)
6. Engine Ignition Timing Retardation: 0% - 40% control efficiency (US EPA, 1993)

Control Options for VOC:

1. Oxidation Catalyst (for lean-burn engines): 60% - 99% control efficiency (Manufacturers of Emission Controls Association, 2015)
2. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): 50% - 90% control efficiency (Manufacturers of Emission Controls Association, 2015)

8D.6 - Economic Feasibility:

The cost of purchasing a new natural gas-fired engine subject to NSPS Subpart JJJJ emission standards can range from $10,000 for a 100 hp engine to $180,000 for a 1,500 hp diesel engine, based on the cost of similar sized diesel engines (Bradley Nelson, 2010).

The difference of NO_X emissions of an existing engine and a new engine is as follows:

- 0.03 tpy for a 50 hp engine

- 1.21 tpy for a 500 hp engine

The following assumptions were used in this analysis:
- The Engine Sizes are 50 hp and 500 hp
- The cost of a 50 hp engine is $5,000
- The cost of a 500 hp engine is $50,000
- An annual interest rate of 7% (US EPA, 2002)
- The economic life of each engine is 20 years
- Negligible annual maintenance costs due to costs most likely being similar to current costs with an existing engine

Based on these assumptions, the cost/ton removed of NO_X for replacing an existing engine with a new engine is as follows:
- $12,238 for a 50 hp engine
- $3,034 for a 500 hp engine

Based on the cost above for NO_X control, it could potentially be cost effective to purchase a new engine subject to the newest emission standards for emergency engines in this size source category as specified in 40 CFR 60 Subpart JJJJ.

Based on the emission standards for VOC of 1.0 g/hp-hr, the emissions calculated using AP-42 emission factors are already less than the emission standards found in 40 CFR 60 Subpart JJJJ. Therefore, it is not cost effective to purchase a new engine subject to the most stringent standards specified in 40 CFR 60 Subpart JJJJ for the control of VOC.

Control Options for NO_x:
1. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): Based on Table V-2 on Page V-3 in "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines", the $/ton of NO_x reduced is $2,100 (California Air Resources Board, 2001). However, this analysis assumes an engine running at 100% load for 2,000 hours annually. This source category is for emergency engines, expected to run conservatively 200 hours per year, most likely at varying loads. This would make the $/ton of NO_x reduced more likely $21,000 or more. Therefore, this is not economically feasible to control NO_x emissions.
2. Turbocharging and aftercooling (part of low emission combustion retrofit): Based on Table V-2 on Page V-3 in "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines", the $/ton of NO_x reduced is $1,100 (California Air Resources Board, 2001). However, this analysis assumes an engine running at 100% load for 2,000 hours annually. This source category is for emergency engines, expected to run conservatively 200 hours per year, most likely at varying loads. This would make the $/ton of NOx reduced more likely $11,000 or more. Depending on site-specific information, it may be cost effective to retrofit existing emergency engines to become low emission combustion units. Because this is considered one of the top feasible control

options for NOx, the remaining NOx control options discussed in the above sections have not been evaluated.

Control Options for VOC:

1. Oxidation Catalyst (for lean-burn engines): Assuming a cost of $15,000 for an oxidation catalyst, an annual interest rate of 7% (United States Environmental Protection Agency, 2002), an economic life of a unit at approximately 20 years, annual maintenance costs of $6,000, and an average 79.5% control efficiency, the cost/ton removed for the installation of an oxidation catalyst is $2,162,873 to $216,287 (Thomas P. Mark, 2003). Therefore, this control option is not economically feasible for natural gas-fired emergency engines.
2. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): Assuming a cost of $13,500 for a non-selective catalytic reduction unit and installation, an annual interest rate of 7% (United States Environmental Protection Agency, 2002), an economic life of a unit at approximately 20 years, annual maintenance costs of $6,000, and an average 70% control efficiency, the cost/ton removed for the installation of a non-selective catalytic reduction unit is $2,418,306 to $241,831 (California Air Resources Board, 2001). Therefore, this control option is not economically feasible for natural gas-fired emergency engines.

8D.7 - Evaluation of Findings & Control Selection:

Control Options for NO_x: The installation of a new emergency stationary natural gas-fired engine subject to the newest requirements for stationary emergency engines as specified in 40 CFR 60 Subpart JJJJ could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart JJJJ. This control selection is not applicable to newer engines. In the absence of replacing an old engine with a new engine, the retrofit of an existing natural gas-fired emergency engine to become a low emissions combustion unit could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart JJJJ. This control selection is not applicable to newer engines. Therefore, the DAQ recommends as BACT a site-by-site analysis to determine as necessary if older engines need to be retrofitted to become low emissions combustion units or completely replaced with new engines.

Control Options for VOC: The DAQ did not find any VOC controls that were cost effective for controlling VOC emissions. Therefore, the DAQ recommends proper maintenance and operation of the emergency stationary natural gas-fired engine as BACT for the control of VOC emissions.

8D.8 - Time for Implementation:

The DAQ recommends 180 days up to 1 year to retrofit an engine to become a low emissions combustion unit or to replace an existing stationary emergency natural gas-fired engine with a new stationary emergency natural gas-fired engine.

8E. - Propane-fired Portable Emergency Generators

8E.1 - Description:

This source category is portable emergency engines that are small, rated less than 150 hp. This source category can be found in industrial, commercial, or institutional settings. Emergency engines are typically used to provide power for sources in emergency situations, when electric power from the public utilities is interrupted. Emergency engines are also typically operated weekly or monthly at zero or low loads for regular maintenance and testing to ensure proper engine operations. Portable emergency engines can be moved from place to place in a source based on need.

8E.2 - Emissions Summary:

This source category could represent a variety of different engines with different sizes and ages. The emissions from these engines vary greatly. To be conservative, base emissions were calculated assuming an older engine, not subject to the standards in 40 CFR 60 Subpart JJJJ. Emissions were calculated for the following engine sizes: 25, 50, 75, 100, and 150 hp. Due to the portability of the engines, it was assumed that the engine capacity would be relatively small. Emission estimates used emission factors from AP-42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1; it was assumed that emissions from propane-fired engines were similar to emissions from natural gas-fired engines (United States Environmental Protection Agency, 2000, p. 2).

This source category can emit direct $PM_{2.5}$, and the following $PM_{2.5}$ precursor pollutants: SO_2, NO_X, and VOC. SO_2 emissions from propane-fired engines are minimal. To determine direct $PM_{2.5}$ from AP-42 emission factors, the CEIDARS List with $PM_{2.5}$ fractions for Internal Combustion – Gaseous Fuel $PM_{2.5}$ Fraction of PM_{10} of 0.998 was used (Mike Krause & Steve Smith, Ph.D., 2006). Based on an EPA guidance memorandum from John S. Seitz to Region Directors (John S. Seitz, 1995), and a response to William O'Sullivan, Director of the New Jersey Division of Air Quality, from EPA Region 2 Chief of the Permitting Section Steven C. Riva (Steven C. Riva, 2006), a total of 200 operating hours per year was used to calculate the PTE for this source category. The 200 operating hours will adequately cover the time when the emergency engine is used for maintenance, testing, and emergency situations.

8E.3 - Control Options:

The following sources were reviewed to identify available control technologies:

- EPA's RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA's Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state regulations
- 40 CFR 60 Subpart JJJJ and 40 CFR 63 Subpart ZZZZ
- Various state-specific example permits
- A thorough literature search using the Google search engine

After a review of the above sources, the DAQ determined that many state and federal regulations provide specific exemptions for the control and applicability of various regulations and control devices to emergency engines. The following control options were found for controlling emissions from stationary natural gas-fired engines:

Control Options for NO_X:

- Non-Selective Catalytic Reduction (for rich-burn engines with carburetors) (CleanAIR Systems, 2009)
- Exhaust Gas Recirculation (CS, 2009)
- Lean NO_X Catalyst (for lean-burn engines) (CS, 2009)
- Selective Catalytic Reduction (for lean-burn engines) (CS, 2009)
- Turbocharging and aftercooling (US EPA, 1993)
- Engine Ignition Timing Retardation (US EPA, 1993)
- Modifying air-to-fuel ratio (US EPA, 1993)

Control Options for VOC:

- Non-Selective Catalytic Reduction (for rich-burn engines) (CS, 2009)
- Oxidation Catalyst (for lean-burn engines) (CS, 2009)

Additional control options for all pollutants include replacement of older engines with new engines, and adherence to emission limitations contained in 40 CFR 60 Subpart JJJJ. 40 CFR 63 Subpart ZZZZ contains no additional requirements for emergency engines beyond operational and maintenance practices. For older engines that do not comply with an emission limitation in 40 CFR 60 Subpart JJJJ, emissions could be controlled by one of the above methods.

8E.4 - Technological Feasibility:

Many of the above control options are possible control options for stationary SI engines used for prime operations, rather than emergency operations. Due to the unique operating scenario of emergency SI engines, several of the technologies are not technically feasible.

Control Options for NO_X:

Non-Selective Catalytic Reduction (for rich-burn engines with carburetors)

Non-selective catalytic reduction techniques are difficult on engines with variable engine load (US EPA, 1993). In addition, emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate optimally. The engine would then need to be operated at higher loads for longer periods of time, fundamentally changing the operation of the emergency engine. This could also be a challenge for many emergency engine applications. However, according to the Washington Department of Ecology Document "Suitability of Spark Ignition, Gaseous Fossil Fuel-Powered Emergency Generators for Air Quality General Order of Approval", Page 10, non-selective catalytic reduction was chosen as BACT for rich-burn emergency engines (Washington State Department of Ecology, n.d.). Therefore, this is a technically feasible control option for stationary emergency SI engines.

Exhaust Gas Recirculation

Exhaust gas recirculation is typically incorporated in new stationary SI engines automatically. Therefore, this is a technically feasible control option for new emergency SI engines. Some exhaust gas recirculation technologies can also be retrofitted to older engines (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency SI engines.

Lean NO_X Catalyst (for lean-burn engines)
Lean NO_X catalysts are a new technology that has demonstrated NO_X emission reductions. The catalyst operates at a narrow temperature range, from 392 °F to 842 °F depending on the catalyst formulation (Manufacturers of Emission Controls Association, 2015). Emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine. This could also be a challenge for many emergency engine applications. Therefore, this is not a technically feasible control option for stationary emergency engines, including SI engines.

Selective Catalytic Reduction (for lean-burn engines)
CARB has determined that selective catalytic reduction, while technologically feasible in some cases, has challenges when applying it to emergency engines. Emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine (Matt Baldwin, 2016). This could also be a challenge for many emergency engine applications. Therefore, this is not a technically feasible control option for stationary emergency engines, including SI engines.

Turbocharging and aftercooling
Turbocharging and aftercooling is typically incorporated in new stationary SI engines automatically. Therefore, this is a technically feasible control option for new emergency SI engines. Existing emergency engines can be modified to be equipped with a turbocharger (Bradley Nelson, 2010). Therefore, this is a technically feasible option for existing emergency SI engines.

Engine Ignition Timing Retardation
Ignition timing can be adjusted on new and existing SI engines; however, an electronic injection control system is needed to ensure sustained NO_X emissions reductions (US EPA, 1993). Most new engines have electronic injection control systems automatically installed; therefore, this is a technically feasible option for new emergency SI engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency SI engines.

Modifying air-to-fuel ratio
New emergency SI engines have electronic injection control systems automatically installed that can modify the air-to-fuel ratio to ensure a lean burn scenario. Therefore, this is a technically feasible option for new emergency SI engines. Existing engines can be retrofitted to include an electronic injection control system (Brent Haight, 2010); therefore, this is a technically feasible option for existing emergency SI engines.

Control Options for VOC:

Non-Selective Catalytic Reduction (for rich-burn engines with carburetors)

Non-selective catalytic reduction techniques are difficult on engines with variable engine load (US EPA, 1993). In addition, emergency engines typically only operate at no or low load for maintenance and testing for 15-30 minutes. Because of this typical operation, the engine exhaust would not reach the temperature required for the catalyst to optimally operate. The engine would then need to be operated at higher loads for longer time periods, fundamentally changing the operation of the emergency engine. This could also be a challenge for many emergency engine applications. However, according to the Washington Department of Ecology Document "Suitability of Spark Ignition, Gaseous Fossil Fuel-Powered Emergency Generators for Air Quality General Order of Approval", Page 10, non-selective catalytic reduction was chosen as BACT for rich-burn emergency engines (Washington State Department of Ecology, n.d.). Therefore, this is a technically feasible control option for stationary emergency SI engines.

Oxidation Catalyst (for lean-burn engines)

Oxidation catalysts are frequently installed on lean-burn engines to control VOC emissions; therefore, this is a technically feasible control option for stationary emergency SI engines (Manufacturers of Emission Controls Association, 2015).

8E.5 - Ranking of Individual and Combined Controls:

Control Options for NO_X:

1. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): 90% - 98% control efficiency (US EPA, 1993)
2. Turbocharging and aftercooling: 87% control efficiency (Considered part of L-E retrofitting) (US EPA, 1993)
3. Exhaust Gas Recirculation: 25% - 50% control efficiency (Alternative Control Techniques Document: Stationary Diesel Engines – similar control efficiency assumed for SI engines) (Bradley Nelson, 2010)
4. Engine Ignition Timing Retardation & Modifying air-to-fuel ratio: 10% - 40% control efficiency (US EPA, 1993)
5. Modifying air-to-fuel ratio: 5% - 40% control efficiency (US EPA, 1993)
6. Engine Ignition Timing Retardation: 0% - 40% control efficiency (US EPA, 1993)

Control Options for VOC:

1. Oxidation Catalyst (for lean-burn engines): 60% - 99% control efficiency (Manufacturers of Emission Controls Association, 2015)
2. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): 50% - 90% control efficiency (Manufacturers of Emission Controls Association, 2015)

8E.6 - Economic Feasibility:

Control Options for NO_X:

1. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): Based on Table V-2 on Page V-3 in "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines", the \$/ton of NO_X reduced is \$2,100 (California Air Resources Board, 2001). However, this analysis assumes an engine running at 100% load for 2,000

hours annually. This source category is for portable emergency engines, expected to run conservatively 200 hours per year, most likely at varying loads. This would make the $/ton of NO_X reduced more likely $21,000 or more. Therefore, this is not economically feasible to control NO_X emissions.

2. Turbocharging and aftercooling (part of low emission combustion retrofit): Based on Table V-2 on Page V-3 in "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines", the $/ton of NO_X reduced is $1,100 (California Air Resources Board, 2001). However, this analysis assumes an engine running at 100% load for 2,000 hours annually. This source category is for portable emergency engines, expected to run conservatively 200 hours per year, most likely at varying loads. This would make the $/ton of NO_X reduced more likely $11,000 or more. Depending on site-specific information, it may be cost effective to retrofit existing portable emergency engines to become low emission combustion units. Because this is considered one of the top feasible control options for NO_X control, the remaining NO_X control options discussed in the above sections have not been evaluated.

Control Options for VOC:

1. Oxidation Catalyst (for lean-burn engines): Assuming a cost of $15,000 for an oxidation catalyst, an annual interest rate of 7% (US EPA, 2002), an economic life of a unit at approximately 20 years, annual maintenance costs of $6,000, and an average 79.5% control efficiency, the cost/ton removed for the installation of an oxidation catalyst is $52,655 (Thomas P. Mark, 2003). Therefore, this control option is not economically feasible for portable propane-fired emergency engines.
2. Non-Selective Catalytic Reduction (for rich-burn engines with carburetors): Assuming a cost of $13,500 for a non-selective catalytic reduction unit and installation, an annual interest rate of 7% (US EPA, 2002), an economic life of a unit at approximately 20 years, annual maintenance costs of $6,000, and an average 70% control efficiency, the cost/ton removed for the installation of a non-selective catalytic reduction unit is $58,803 (California Air Resources Board, 2001). Therefore, this control option is not economically feasible for portable propane-fired emergency engines.

8E.7 - <u>Evaluation of Findings & Control Selection:</u>

Control Options for NO_X: The retrofit of an existing portable propane-fired emergency engine to become a low emissions combustion unit could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart JJJJ. This control selection is not applicable to newer engines. Therefore, the DAQ recommends as BACT a site-by-site analysis to determine as necessary if older engines need to be retrofitted to become low emissions combustion units.

Control Options for VOC: The DAQ did not find any VOC controls that were cost effective for controlling VOC emissions. Therefore, the DAQ recommends proper maintenance and operation of the emergency stationary diesel engine as BACT for control of VOC emissions.

8E.8 - <u>Time for Implementation:</u>

The DAQ recommends 180 days up to 1 year to retrofit an engine to become a low emissions combustion unit.

9. - Kilns

9.1 - Description:

A kiln is a furnace or oven for burning or drying material. Kilns discussed in this section are very small and are used by schools and colleges. Students use these kilns in classes to make clay ceramic pieces such as mugs and plates. Kilns may be heated with electricity or fired with natural gas. Temperatures inside kilns can exceed 2200 ^{o}F. Kiln usage varies depending on curriculum and class size (Hirtle, Teschke, Netten, & Brauer, 1998).

9.2 - Emissions Summary:

For natural gas-fired kilns, emissions are estimated using annual natural gas consumption of 140 MMBtu per year. Emissions factors (EPA, 1998) for residential furnace (less than 0.3 MMBtu/hr) are used to calculate the following emissions:

PM_{10} = 0.00 tons/year
$PM_{2.5}$ = 0.00 tons/year
NO_X = 0.01 tons/year
SO_2 = 0.00 tons/year
CO = 0.00 tons/year
VOC = 0.00 tons/year

9.3 - Control Options:

Available control technologies for particulate emissions from the kilns include: baghouses, filters, scrubbers, cyclones, and electrostatic precipitators. Available control technologies for NO_X emissions from the kilns include: low NO_X burners (Air & Waste Management Association, 1992).

9.4 - Technological Feasibility:

Exhaust gas streams from kilns have temperatures exceeding 2200°F. Standard bags used in baghouses and standard filters cannot be used with high temperatures; therefore, baghouses and filters are infeasible to control particulate emissions from kilns. Cyclones, scrubbers, and electrostatic precipitators are feasible technologies to control particulate emissions from kilns. Low NO_x burner technology is a feasible control technology to reduce NO_x emissions from kilns (Air & Waste Management Association, 1992).

9.5 - Ranking of Individual and Combined Controls:

$PM_{2.5}$ Control

1. Electrostatic precipitators offer high control efficiency at 99.9%.
2. Wet scrubbers can control particulate matter at 95% efficiency.
3. Cyclones control coarse particulate matter very well, but cannot remove fine particles effectively. $PM_{2.5}$ controls using cyclones are estimated at less than 10% efficient.

NO_X Control

1. Low NO_X burners can reduce NO_X emissions up to 50%.

Combine $PM_{2.5}$ and NO_X Control

1. Low NO_X burner technology can be combined with either electrostatic precipitators, wet scrubbers, or cyclones to control NO_X and particulate emissions.

(Air & Waste Management Association, 1992)

9.6 - Economic Feasibility:

Because emissions from the kilns are small (less than 0.01 tons/year for all pollutants), add-on control devices such as scrubbers or electrostatic precipitators for particulate emissions, and low NO_x burners for NO_X emissions are not economically feasible.

9.7 - Evaluation of Findings & Control Selection:

No technologies are both technologically and economically feasible to control emissions from these small kilns.

9.8 - Time for Implementation:

Since there are no economically feasible controls, no time for implementation is needed.

10. - Laboratory Fume Hoods

10.1 - Description:

Laboratory fume hoods are used in educational and research institutions. Many manufacturing sources also use the hoods to test their products and for research and development. A variety of materials could be analyzed and tested under the hoods. The hoods are usually vented through openings on rooftops.

10.2 - Emissions Summary:

Emissions from the Laboratory fume hoods vary in quantity and species. Emissions may include HAP, VOC, and metals in rare cases. Emissions do not usually include particulate matter in the exhaust streams. VOC emissions from fume hoods were conservatively assumed to be 100 lbs per year for this analysis.

10.3 - Control Options:

Available control technologies for emissions from the Laboratory fume hoods include thermal oxidation, condensation, and activated carbon absorption. There are also workplace practices that help reduce emissions such as (1) scale down experiments, (2) use less volatile substitutes, and (3) seal containers when they are not in use (UCI, 1995).

10.4 - Technological Feasibility:

All above listed control technologies and workplace practices can help reduce VOC emissions. However, because the concentrations of VOC in the exhaust streams from laboratory fume hoods are very low, and because there may be different VOC emissions with different physical and chemical characteristics, condensation technology is infeasible for VOC removal from such exhaust streams (EPA, 1995).

10.5 - Ranking of Individual and Combined Controls:

1. Thermal oxidation technology can provide VOC control efficiency of more than 95%
2. Activated carbon absorption can provide VOC control efficiency of more than 90%
3. Workplace practices can help reduce the use of VOC containing materials.

(Air & Waste Management Association, 1992)

10.6 - Economic Feasibility:

For a small thermal oxidation unit that processes 1,000 scfm exhaust gas from a laboratory fume hood, the cost is estimated below in 1999 Dollars (EPA, 2000)
Equipment: $59,000
Installation: $17,700
Indirect cost: $30,090

Therefore, the total Capital cost in 1999 Dollars is estimated at $106,790. Using an average of 3% inflation rate, the total cost is estimated at $181,803 in 2017 Dollars. If 10% interest rate and 10-year equipment life are assumed, annualized capital cost is estimated at $29,588. If annual operating cost is assumed to be 10% of the annualized capital cost, the total annualized cost is $32,547. The annualized cost is $32,547/(95% x 0.05 tons) = $685,200 per ton of VOC removed. Based on these costs, thermal oxidation is not economically feasible to control VOC emissions from a laboratory fume hood.

Activated carbon is a low-cost technology that can remove VOC from exhaust air streams. Depending on the inlet pollutant concentrations and air flow rate, the annualized cost to treat low concentration VOC can be as high as $1720 for 0.04 tons of VOC removed (D. Bruce Henschel, 1998). Using the same systems to treat the exhaust air streams from a laboratory fume hood, the annualized cost would be $34,400 ($60,320 in 2017 Dollars) per ton of VOC removed. Based on these costs, activated carbon is not economically feasible to control VOC emissions from a laboratory fume hood.

The workplace practices listed above are economically feasible to control emissions from the laboratory fume hoods.

10.7 - <u>Evaluation of Findings & Control Selection:</u>

As discussed above, add-on control devices, such as thermal oxidation and condensation devices, are not economically feasible to control VOC emissions from the laboratory fume hoods.   If a laboratory fume hood emits more than 0.5 tons per year of VOC, add-on control technology may become economically feasible. A case-by-case analysis should be performed for larger-emitting fume hoods. Workplace practices including scale down experiments, use less volatile substitutes, and seal containers when not in use, are selected as BACT for laboratory fume hoods.

10.8 - <u>Time for Implementation:</u>

New sources should implement workplace practices upon startup. Existing sources should be currently implementing workplace practices.

11. - Lime Storage and Handling

11.1 - Description:

A lime loadout system refers to the transfer of lime from a storage source to a truck or vehicle for transport. Lime is stored in silos, which open to release the product into the transfer vessel. Due to the caustic nature and low weight of lime, the entire system is enclosed. Emissions from this system are generated through venting at the top of the silo or fugitive releases due to system failures through aging ("Safe and Efficient Transport of Lime," 2017).

The EPA estimates that failures occur as the caustic lime wears down aging equipment and through operator error. Over-feeding the system can result in system clogging and failure. These failures create holes and blockages that result in system emissions.

The movement of the lime to the transfer equipment creates dust at the vent points. This dust generates the suspension of PM_{10} and $PM_{2.5}$ particles.

11.2 - Emissions Summary:

Lime transfer points emit PM_{10} and $PM_{2.5}$. Emissions occur as the material is vented in loading and unloading processes within the silo.

Title V and Minor Sources in Utah are permitted with production limits ranging, in tons per year, from 200,000 (Castell, 2015) to 750,000 (Anderson, 2011). An average throughput of 475,000 tons per year of lime produced and transferred is assumed for this evaluation.

11.3 - Control Options:

The EPA and the State of Utah have regulations and requirements that apply to this process.

40 CFR 63 Subpart AAAAA applies to lime manufacturing plants that are major sources due to major HAP emissions. This subpart defines processed stone handling (PSH) to include bulk loading or unloading systems. Table 1 of this subpart applies to PSH operations and limits subject sources to the following (e-CFR, 2004):

- Fugitive Emissions –10%
- Stack emissions from all PSH –7%
- PM emissions must not exceed 0.05 g/dscm

40 CFR 60 Subpart OOO applies to nonmetallic mineral processing plants' enclosed truck or railcar loading stations. This subpart applies to this activity and limits PM emissions to 0.022 gr/dscf for any emission unit constructed between 8/31/1983 and 4/21/2008. Sources constructed or modified on or after 4/22/2008 must meet a limit of 0.014 gr/dscf. (e-CFR, 2009).

Utah rule R307-309 for Nonattainment and Maintenance Areas for PM_{10} and $PM_{2.5}$: Fugitive Emissions and Fugitive Dust applies to this process. Specifically, R307-309-5: General Requirements for Fugitive Dust limits on-site fugitive dust opacity to 20% and 10% at the property boundary. Additionally, R307-309-6: Fugitive Dust Control Plan requires that sources create and follow a plan to reduce and mitigate fugitive dust emissions.

Other states have varying requirements for this process. New Jersey's State BART analysis from 2011 lists possible PM controls for this process as: particle enclosure and a fabric filter (pg.407); or ducting to a control system that has a bin vent filter with a 100% capture rate and a 0.02 gr/dscf filtration rate for PM_{10} (pg. 467) (State of New Jersey Department of Environmental Protection, 2011). Missouri requires that all loadout operations be controlled by a baghouse ("DNR MACC- Permit to Construct: Mississippi Lime Company," 2015). The Nelson Lime Plant in Arizona was permitted with a baghouse controlling lime loadout into railcars and a subsequent emission limit of 0.01 gr/dscf ("Nelson Lime Plant - Permit #42782")

To meet these requirements possible controls include; using enclosed trucks during transport, utilizing a venting system controlled with vent, fabric filtered vents, or a baghouse ("Lime Handling Systems," 1984).

11.4 - <u>Technological Feasibility:</u>

A baghouse can be installed at the venting point to reduce emissions for this process. Fabric filtered bin vents are standard design for lime silos and have been applied to all existing permitted sources in the State of Utah. The use of enclosed trucks is required due to the hazardous potential of lime products and is an industry standard ("Lime Handling Systems," 1984).

11.5 - <u>Ranking of Individual and Combined Controls:</u>

Both a baghouse and a bin vent will control 99% of emissions from the lime loadout process. A limit of 0.01 gr/dscf on the filters will ensure decreased opacity and system effectiveness.

11.6 - <u>Economic Feasibility:</u>

There are no additional costs associated with the proposed controls. Bin vents are an efficient and standard control for PM_{10} and $PM_{2.5}$. Baghouses with the same efficiency can be explored based on company needs. There are no additional costs for bin vent controls as they are an industry standard.

11.7 - <u>Evaluation of Findings & Control Selection:</u>

Both bin vents and baghouses are feasible options for lime silo controls. A baghouse can control multiple silos at once. The use of a baghouse may be more applicable depending on the operator's needs. Bin vents are an acceptable control for lime silos and operates independently on each silo. This control limits emissions during material transfers and movements. As the system is enclosed and the only venting point is through the silo vent, this control is considered BACT for this process.

11.8 - <u>Time for Implementation:</u>

Bin vents are already standard controls and are implemented on existing equipment. New permits and equipment should be required to install controls that meet a 0.01 gr/dscf requirement. Sources should verify this limitation through manufacturer specifications or on-site testing. All sites should operate and maintain equipment according to the manufacturer's specifications.

12. - Mining and Fugitive Dust

12.1 - Description:

This section focuses on various mining emission units and activities. Mineral products are mined from the earth's surface. The mining and processing of minerals produce $PM_{2.5}$. These emissions may be emitted as fugitive dust, fugitive emissions, or non-fugitive emissions.

12A. - Cone Crusher

12A.1 - Description:

A cone crusher is generally used as a secondary crusher in a crushing circuit. The vertical drive shaft in the cone crusher rotates the mantle below the bowl liner, squeezing and crushing the material between the mantle and the bowl liner. Cone crushers are widely used to reduce material sizes in various industries including sand and gravel processing operations, coal mining and salt processing operations. NSPS Subpart OOO has a list of nonmetallic minerals that can be processed by crushers.

12A.2 - Emissions Summary:

In aggregate processing operations, crushers crush aggregate material. Aggregate material usually carries moisture in it; therefore, emissions from the crushing operations are small. Factors affecting emissions include the size of material to be processed, the surface moisture content, the throughput rate, operating practices used, and topographical and climatic/seasonal conditions. Annual emissions are usually calculated using the throughput rate in tons per year multiplied by the emission factor in AP-42 Table 11.19.2-2 (USEPA, 2004). Emission factors for $PM_{2.5}$ are limited. The table provides emission factors for tertiary crushing (0.00010 lbs/ton) and fines crushing (0.000070 lbs/ton) under controlled conditions. In order to obtain uncontrolled emission factors, it is assumed that control efficiencies for PM_{10} and $PM_{2.5}$ are the same.

This results in 0.00044 lbs/ton uncontrolled emission factor for tertiary crushing and 0.00088 lbs/ton uncontrolled emission factor for fines crushing. For a cone crusher that processes 1 million tons of aggregate material, the uncontrolled $PM_{2.5}$ emissions are calculated at 0.22 tpy for tertiary crushing, or 0.44 tpy for fines crushing.

12A.3 - Control Options:

Available control technologies for crushing operations include water application, enclosures and add-on control devices such as baghouses, wet scrubbers, cyclones, and electrostatic precipitators. Water application and enclosures are typically used where fugitive particulate emissions are generated.

For cone crushers operating in a $PM_{2.5}$ nonattainment area, the UAC requires visible emissions from crushers not to exceed 12% opacity on site (R307-312-4), or 10% at the property boundary (R307-309-5). NSPS Subpart OOO requires visible emissions not to exceed 12% opacity for crushers manufactured on or after April 22, 2008. Rule evaluations conducted by the SJVAPCD did not provide stricter opacity requirements from other agencies.

12A.4 - Technological Feasibility:

All above listed control technologies can provide controls for $PM_{2.5}$ emissions.

12A.5 - Ranking of Individual and Combined Controls:

1. Total enclosures can provide near 100% control for $PM_{2.5}$ emissions.
2. Baghouse and electrostatic precipitators offer high control efficiency (99.9%).

3. Wet scrubbers can control particulate matter at 95% efficiency.
4. Water application can prevent particulate emissions with 77% efficiency, and is widely used in aggregate processing operations.
5. Cyclones control coarse particulate matter very well, but cannot remove fine particles effectively. $PM_{2.5}$ controls using cyclones are estimated at less than 10% efficient.

See the AP-42 section referenced in "Emission Summary". Additional reference can be found in Chapter 3 of Air Pollution Engineering Manual (Air & Waste Management Association, 1992).

12A.6 - <u>Economic Feasibility:</u>

For a tertiary cone crusher to process 1 million tons of aggregate material, 0.22 tons of $PM_{2.5}$ would be produced. Control costs include purchased equipment cost, direct installation costs, and indirect installation costs, in addition to costs for site preparation. On an annual basis, these costs would total thousands of dollars if not tens of thousands of dollars. For such small emissions, any add-on devices or enclosures are not economically feasible to control $PM_{2.5}$ emissions from cone crushers. Water application has been determined to be economically feasible to control $PM_{2.5}$ emissions from cone crushers.

12A.7 - <u>Evaluation of Findings & Control Selection:</u>

Water application is selected as the BACT for cone crushers. Water application shall be used to maintain visible emissions not to exceed opacity limits in the UAC as mentioned above.

12A.8 - <u>Time for Implementation:</u>

The current UAC requires cone crushers to have water application and meet the opacity limits above. New sources are required to meet these limits upon startup, and existing sources must currently meet these limits.

12B. - Conveyor Transfer Points and Drop Points

12B.1 - Description:

Conveyor belts are used to transport material. The belts, used to carry material, rotate around two or more pulleys. One or more pulleys are powered to move the belts. Conveyor belts are widely used to transport loose material in various industries including aggregate processing operations, coal and ore mining, and salt processing operations.

12B.2 - Emissions Summary:

Particulate emissions from conveyor transfer and drop points are small. Factors affecting emissions include the size of material to be processed, the surface moisture content, the throughput rate, operating practices used, topographical and climatic/seasonal conditions. Annual emissions are usually calculated using the throughput rate in tons per year multiplied by the emission factor in AP-42 Table 11.19.2-2 (USEPA, 2004). Emission factors for $PM_{2.5}$ are very limited. The table only provides emission factor under controlled conditions (0.000013 lbs/ton). In order to obtain uncontrolled emission factors, it is assumed that control efficiencies for PM_{10} and $PM_{2.5}$ are the same. This results in 0.00031 lbs/ton uncontrolled emission factor for conveyor transfer and drop points. For a conveyor transfer/drop point that processes 1 million tons of aggregate material, the uncontrolled $PM_{2.5}$ emissions are calculated at 0.16 tpy.

12B.3 - Control Options:

Available control technologies for crushing operations include water application, enclosures and add-on control devices such as baghouses, wet scrubbers, cyclones, and electrostatic precipitators. Water application and enclosures are typically used where fugitive particulate emissions are generated.

For conveyors operating in a $PM_{2.5}$ nonattainment area, the UAC requires visible emissions from conveyor transfer points not to exceed 7% opacity (R307-312-4), and from conveyor drop points not to exceed 20% opacity on site and 10% opacity at the property boundary (R307-309-5). NSPS Subpart OOO requires 7% opacity limit from conveyor transfer points for conveyors manufactured on or after April 22, 2008.

12B.4 - Technological Feasibility:

All above listed control technologies can provide controls for $PM_{2.5}$ emissions.

12B.5 - Ranking of Individual and Combined Controls:

1. Total enclosures can provide near 100% control for $PM_{2.5}$ emissions.
2. Baghouse and electrostatic precipitators offer high control efficiency (99.9%).
3. Wet scrubbers can control particulate matter at 95% efficiency.
4. Water application can prevent particulate emissions with 95% efficiency, and is widely used in aggregate processing operations.
5. The cyclones control coarse particulate matter very well, but cannot remove fine particles effectively. $PM_{2.5}$ controls using cyclones are estimated at less than 10% efficient.

See the AP-42 section referenced in "Emission Summary". Additional reference can be found in Chapter 3 of Air Pollution Engineering Manual (Air & Waste Management Association, 1992).

12B.6 - Economic Feasibility:

For a conveyor transfer/drop point to process 1 million tons of aggregate material, 0.16 tons of $PM_{2.5}$ would be produced. Control costs include purchased equipment cost, direct installation costs, and indirect installation costs, in addition to costs for site preparation. On an annual basis, these costs would total thousands of dollars if not tens of thousands of dollars. For such small emissions, any add-on devices or enclosures are not economically feasible to control $PM_{2.5}$ emissions. Water application has been determined to be economically feasible to control $PM_{2.5}$ emissions from conveyor transfer/drop points.

12B.7 - Evaluation of Findings & Control Selection:

Water application is selected as the BACT for cone crushers. Water application shall be used to maintain visible emissions not to exceed opacity limits in the UAC as mentioned above.

12B.8 - Time for Implementation:

The current UAC requires conveyor transfer/drop points to have water application and meet the opacity limits above. New sources are required to meet these limits upon startup, and existing sources must currently meet these limits.

12C. - Earthen Drilling

12C.1 - Description:

Earthen drilling has the potential to generate particulate emissions in the form of drill cuttings during the pneumatic clearing of the hole.

12C.2 - Emissions Summary:

The emissions from drilling are as follows: 1.3 lbs of suspended particulate per hole (AP-42 Table 8.24-4)
Colorado Department of Health assigns a 75% control efficiency for water injection drilling (United States., 1988), however, control efficiencies of 90% are reported elsewhere. (*Castle Mountain Mine Open Pit Heap Leach Gold Mine Expansion Project, San Bernadino County*, 1997)

$$\frac{Holes}{year} = \frac{tons/day}{4{,}000\ tons/hole} \times 365\ days\ per\ year$$

$$Uncontrolled\ Emissions\ (tpy) = 1.3\frac{lbs}{hole} \times \frac{holes}{year} \times \frac{1\ tons}{2{,}000\ lbs}$$

$$Emissions\ with\ water\ Injection\ (tpy) = Uncontrolled\ emissions\ \times (1 - CF)$$

Where:

- CF = Control factor in decimal form

12C.3 - Control Options:

- Water Injection
- Dust collection systems

12C.4 - Technological Feasibility:

Water injection is a wet drilling technique in which water or water plus a wetting agent or surfactant is injected into the compressed air stream particles as they are blown from the hole, these particles drop at the drill collar as damp pellets rather than becoming airborne. However, if too much water is sent downhole a mud slurry can trap the bit, causing damage to equipment. Proper water injection requires trained operators, but is common practice and routinely implemented to control drilling operations at mining sites, and control efficiencies can reach 90%. (*Castle Mountain Mine Open Pit Heap Leach Gold Mine Expansion Project, San Bernadino County*, 1997)

The use of dust collection systems, to control dust from the drilling process is technologically feasible, but has some logistical constraints. These constraints consist of capturing fugitive dust from drilling operations that are not stationary, because the constant movement of entire systems is time consuming and slows the mining operations down. Increased wear and tear on equipment is also a problem as dust collection systems require large fan systems to ensure that the control airflow is at least 3 times higher than that of the air stream used for flushing drill cuttings in order to maintain a negative pressure within the dust shroud. (“OSHA_FS-3633.pdf,” n.d.) The dust shroud surrounding the drill bit and hole is not completely sealed and the negative pressure within allows additional particulate matter to enter the dust collection system. Control efficiencies are similar to that of water injection technologies and is around 90%. (*Castle Mountain Mine Open Pit Heap Leach Gold Mine Expansion Project, San Bernadino County*, 1997)

12C.5 - <u>Ranking of Individual and Combined Controls:</u>

1. Water Injection
2. Dust Collection

12C.6 - <u>Economic Feasibility:</u>

The use of a material shroud is required for both control technologies; this shroud contains the particulate matter from drill cuttings to a specific area that can then be controlled.

Water injection can be achieved at a low cost. Water injection occurs using wet sprays added to the airstream sent downhole to clear the drill cuttings, and is not in constant operation. Water injection requires a skilled operator but does not include as many moving parts as a dust collection system, requires less maintenance, and is considered a cheaper option for control.

Dust collection systems rely on a negative pressure within the dust shroud. Exhaust fans that operate continuously during the entire drilling process provide the negative pressure in the dust shroud that facilitates the capture of drill cuttings. Dust collection technologies are considered more expensive than water injection but do not require the same level of technical knowledge. The particulate matter within the dust shroud damages the fan motor and blades, and routine maintenance is required to keep the systems in working order.

12C.7 - <u>Evaluation of Findings & Control Selection:</u>

The two control technologies implemented on earthen drilling achieve similar control efficiencies. Water injection is a cheaper method of control that requires less maintenance on equipment but more training of the individual operating the equipment. Dust collection is more costly than water injection, but requires less knowledge to operate.

A tradeoff is made on the implementation of a control strategy for drilling operations, one that is cheap to operate requires more training the other is costly to operate but cheap to train. A detailed cost analysis was not performed for either case, as control efficiencies are similar. The source should determine what option best fits their operational strategy and implement either water injection or dust collection as they see fit.

12C.8 - <u>Time for Implementation:</u>

Earthen drilling should not be occurring without the implementation of a control technology. As the above technologies yield similar control efficiencies, one or the other should be in place prior to drilling.

12D. - Explosive Blasting

12D.1 - Description:

Above ground mining operations use blasting to propagate large areas of aggregate for effective removal. An explosive agent is used to target large surface landmasses and remove overburden. This explosion propels PM_{10} and $PM_{2.5}$ laden dust into the ambient atmosphere.

12D.2 - Emissions Summary:

Blasting activities generate PM_{10} and $PM_{2.5}$. Pollutant emissions are dependent on the surface area, in square feet, of each blast.

AP-42 Chapter 11.9 demonstrates how to estimate PM_{10} and $PM_{2.5}$ emissions from coal and overburden blasting. The blast surface area is multiplied by the conversion factor of 1.4 $x10^{-5}$. From Table 11.9-1, PM_{10} (0.52) and $PM_{2.5}$ (0.03) emission factors are multiplied with the result of the area conversion. This calculation determines total emissions from each blast ("Chapter 11.9," 1998).

12D.3 - Control Options:

There are no federal air quality regulations that apply to this activity. The State of Utah maintains rules for the blasting procedures:

UAC rule R307-309 for Nonattainment and Maintenance Areas for PM_{10} and $PM_{2.5}$: Fugitive Emissions and Fugitive Dust applies to this process. Specifically, R307-309-5: General Requirements for Fugitive Dust limits on-site fugitive dust opacity to 20% and 10% at the property boundary. Additionally, R307-309-6: Fugitive Dust Control Plan requires that sources create and follow a plan to reduce and mitigate fugitive dust emissions. R307-309-6(4)(b): Blasting, includes the items that must be addressed in the fugitive dust control plan. These items are required in the State of Utah for explosive blasting.

The RBLC yielded no additional control options for explosive blasting.

Due to the nature, impacted area, and depth of explosive blasting there are no additional controls beyond best practices and management for blasting. A 2017 Utah NOI aptly defined the available options for this process, stating:

> "BACT for blasting is sound operating practices and good process design. These practices include blasting during low wind events when possible and conducting blasting in a manner to prevent over-shoot. Additionally, design of blasting activity will maximize hole depth to decrease surface area affected by blasting" (Kleinfelder, 2017).

12D.4 - Technological Feasibility:

No additional controls are feasible due to the nature of this process.

12D.5 - Ranking of Individual and Combined Controls:

The only control option is best management practices.

12D.6 - Economic Feasibility:

There are no additional costs associated with existing best practices and standard operations.

12D.7 - Evaluation of Findings & Control Selection:

Best operating practices and management are considered BACT for this activity. A requirement for blasting during low wind events is a potential requirement the State can explore in rulemaking to minimize the impact of the blast. Limitations on the amount, area, and timing of blasting can be explored per source.

12D.8 - Time for Implementation:

All sources in a $PM_{2.5}$ nonattainment area must meet the state requirements in R307-309 for explosive blasting at all times of operation.

12E. - Exposed and Disturbed Areas

12E.1 - Description:

During the mining process any seeded land, stripped overburden, or graded overburden from initial removal to the time when new vegetation emerges has the potential to emit particulate matter from climate conditions, i.e. wind.

12E.2 - Emissions Summary:

Exposed and Disturbed Areas emissions are generated using AP-42, Table 11.9-4. Uncontrolled Particulate Emission Factors for Open Dust Sources at Western Surface Coal Mines, as follows:

$$Annual\ Emissions\ \left(\frac{tons}{year}\right) = EF\,\frac{ton}{(acre)(year)} \times Acres\ \times OT\ \left(\frac{days}{year}\right) \times \frac{year}{365\ days}$$

Where:

- EF = Emission Factor
- OT = Operating Time

Emission Factors:

Total Suspended Particulate (TSP) = 0.38 $\left(\frac{tons}{(acre)(year)}\right)$ (“c11s09.pdf,” n.d.)

PM_{10} = 0.32 $\left(\frac{tons}{(acre)(year)}\right)$

*Estimated to be 85% of TSP emission factor (“appb-2.pdf,” n.d.)

$PM_{2.5}$ = 0.11 $\left(\frac{tons}{(acre)(year)}\right)$

*Estimated to be 30% of TSP emission factor (“appb-2.pdf,” n.d.)

12E.3 - Control Options:

- Watering exposed areas
- Minimal disturbance of the area
- Planting vegetation

12E.4 - Technological Feasibility:

Watering exposed areas is not technically feasible due to the vast size of the exposed areas. Even a small mining operation can have excess of 20 acres of exposed and disturbed area. This large area coupled with the hot dry climate of Utah would require copious amounts of water be added. This would require a dedicated water truck fleet to maintain the exposed and disturbed areas with enough moisture to mitigate fugitive dust emissions.

Minimal disturbance of the area will help minimize emissions by reducing the availability of smaller particulate matter at the surface, which can be present by continual disturbance. Planting local vegetation on exposed and disturbed areas that is not reclaimed quickly can reduce particulate emissions. If local vegetation is used it should require no watering and the root structure of the plants will help minimize the availability of particulate matter, and return the exposed areas back to native land reducing emissions.

12E.5 - Ranking of Individual and Combined Controls:

1. Minimal disturbance & planting vegetation
2. Planting vegetation
3. Watering exposed area
4. Minimal disturbance

12E.6 - Economic Feasibility:

Planting vegetation is generally done with hydro-seeding, a technique where a slurry of seed and mulch are sprayed onto the surface being sowed with seeds. The costs for hydro-seeding can vary widely, but for larger commercial jobs can be as low at 7 cents a sq/ft (Phatak, 2016), or $3,050 per acre. Given that sources would require many acres to be seeded this cost can be burdensome. If we assume that vegetation would control 100% of emissions and 1 acre of exposed area PM_{10} emissions are 0.231 tons annually, and $PM_{2.5}$ emissions are 0.082 tons annually, the cost per ton removed per acre would be $13,203 and $37,195 respectively.

There is no cost associated with minimal disturbance; minimal disturbance is considered good site management.

The cost of purchasing a water truck and watering the large area is not viable given that it would only control 70% of emissions when damp (Regg Olsen, 2008a), which would require multiple watering's per acre per day, as such this was not evaluated.

12E.7 - Evaluation of Findings & Control Selection:

The control option that is technically feasible and economically viable is minimal disturbance of the area. Minimal disturbance will prevent stirring of surface particulates and will help reduce fugitive emissions on site. It will also provide ample time for natural vegetation to take root without manually planting vegetation for further emission reductions. This option is considered BACT for exposed and disturbed areas.

Planting vegetation was eliminated due to the economic burden it would place on sources as they continually mine and increase the volume of these areas. Similarly, the costs associated with surface watering of this area would be high and was eliminated due to technical and environmental feasibility concerns.

Additionally, the source must comply with R307-309 and implement the controls necessary to maintain the opacity limitations listed in the rule. Maintaining the 20% opacity on site and the 10% opacity at the property boundary are considered BACT, common practice demonstrates that this can be met via minimal disturbance of exposed areas.

12E.8 - Time for Implementation:

No equipment needs to be installed, and as such, this can be implemented with good site management from the time the source begins to operate. This is also considered common practice for sources currently in operation, and should require no additional time for implementation.

12F. - Feed Hopper

12F.1 - Description:
Feed hoppers are the first equipment that receives raw aggregate material from loaders for further processing.

12F.2 - Emissions Summary:
Factors affecting emissions from feed hoppers include the size of material to be loaded, the surface moisture content, the throughput rate, operating practices used, topographical and climatic/seasonal conditions. Annual emissions are usually calculated using the throughput rate in tons per year multiplied by the emission factor in AP-42 Table 13.2.4 (USEPA, 2006). There are three parameters used to calculate the $PM_{2.5}$ emission factor: particle size multiplier (k = 0.053 for $PM_{2.5}$ emissions), mean wind speed (U), and material moisture content (M). For loading of 1 million material a year, assuming U = 7 miles/hr and material moisture content M = 4%, the uncontrolled $PM_{2.5}$ emission are estimated at 0.05 tpy.

12F.3 - Control Options:
Available control technologies for feed hoppers include water application, enclosures and add-on control devices such as baghouses, wet scrubbers, cyclones, and electrostatic precipitators. Water application and enclosures are typically used where fugitive particulate emissions are generated. To minimize wind effect, the drop distance should also be minimized to reduce $PM_{2.5}$ emissions.

For feed hopper operations in a $PM_{2.5}$ nonattainment area, the UAC requires visible emissions from screens not to exceed 20% opacity on site and 10% opacity at the property boundary (R307-309-5).

12F.4 - Technological Feasibility:
All above listed control technologies can provide controls for $PM_{2.5}$ emissions.

12F.5 - Ranking of Individual and Combined Controls:
1. Total enclosures can provide near 100% control for $PM_{2.5}$ emissions.
2. Baghouse and electrostatic precipitators offer high control efficiency (99.9%).
3. Wet scrubbers can control particulate matter at 95% efficiency.
4. Water application and minimizing drop distance can be used at the same time to control $PM_{2.5}$ emissions from feed hoppers.
5. Water application can effectively prevent particulate emissions. Moisture content increase from 4 to 5% in the material will reduce $PM_{2.5}$ emissions by 27% for the conditions mentioned above.
6. Cyclones control coarse particulate matter very well, but cannot remove fine particles effectively. $PM_{2.5}$ controls using cyclones are estimated at less than 10% efficient.
7. Reducing drop distance will help minimize the wind effect and thus reduce $PM_{2.5}$ emissions.

See the AP-42 section referenced in "Emission Summary". Additional reference can be found in Chapter 3 of Air Pollution Engineering Manual (Air & Waste Management Association, 1992).

12F.6 - <u>Economic Feasibility:</u>

For feed hopper loading of 1 million tons of material, 0.05 tons of $PM_{2.5}$ will be produced. Control costs include purchased equipment cost, direct installation costs, and indirect installation costs, in addition to costs for site preparation. On an annual basis, these costs would total thousands of dollars if not tens of thousands of dollars. For such small emissions, any add-on devices or enclosures are not economically feasible to control $PM_{2.5}$ emissions from feed hopper loading operations. Water application and minimizing drop distance have been determined to be economically feasible to control $PM_{2.5}$ emissions from feed hopper loading operations.

12F.7 - <u>Evaluation of Findings & Control Selection:</u>

Water application and minimizing drop distance are selected as the BACT for feed hopper loading operations. Both methods shall be used to maintain visible emissions not to exceed opacity limits in the UAC mentioned above.

12F.8 - <u>Time for Implementation:</u>

The current UAC requires that feed hoppers and other sources of fugitive dust meet the opacity limits above. New sources are required to meet these limits upon startup, and existing sources must currently meet these limits.

12G. - Haul Roads

12G.1 - Description:

Fugitive particulate emissions are associated with haul roads. The vehicular disturbance of dust generates $PM_{2.5}$ emissions. Haul roads are present on sources associated with mining operations and other industrial operations. Many site-specific factors apply when estimating emissions from haul roads, which include: vehicle miles traveled on the haul roads, vehicle weight, and surface silt percentage of haul road material. These site-specific factors make haul road emissions vary greatly by source activity and location.

12G.2 - Emissions Summary:

Emissions for unpaved haul roads can be calculated using the equation found in AP-42 Chapter 13.2.2 (“c13s0202.pdf,” n.d.):

$$k\left(\left(\frac{s}{12}\right)^{a}\left(\frac{W}{3}\right)^{b}\right)\times\left(1-\left(\frac{CE}{100}\right)\right) = EF$$

Where:

- k (lb/VMT) = Particle Size Multiplier (PM_{10} = 1.5, $PM_{2.5}$ = 0.15)
    - VMT = Vehicle Miles Traveled
- a = 0.9
- b = 0.45
- s = Surface Silt Content (%) (Ranges from 1.8-25.2, commonly 4.8)
- W = Vehicle Weight (tons)
- CE = Control Efficiency (%) (Regg Olsen, 2008b)
    - 70% - Basic watering
    - 75% - Basic watering and road base
    - 85% - Chemical suppressant and watering
    - 90% - Paved road surface with sweeping and watering
    - 95% - Paved road surface with vacuum sweeping and watering

12G.3 - Control Options:

- Watering
- Watering with road base
- Watering with chemical suppressant
- Paving
    - Sweeping and watering
    - Vacuum sweeping and watering

12G.4 - Technological Feasibility:

UAC R307-309 Nonattainment and Maintenance Areas for PM_{10} and $PM_{2.5}$: Fugitive Emissions and Fugitive Dust, requires that haul roads meet a 20% opacity limit on site and a 10% opacity limit at the site boundary. The controls implemented must ensure that the opacity limit is not exceeded. All control options for haul roads are technically feasible at most sources; however, specific scenarios can affect the feasibility of a control option based on the conditions on site.

Watering with road base is technically feasible. Road base is a stable product for road use, and limits the available amount of particulates through compaction of the surface. Watering the road base further limits the available amount of particulates that can be disturbed causing fugitive emissions.

Chemical suppressants can be problematic for sources, such as the Kennecott Copper Mine, that have sloped roadways. Chemical dust suppressants control fugitive dusts from haul roads by temporarily sealing the surface. This sealing property can lower the coefficient of friction on the roadway creating safety issues, such as slippery roads that are difficult to steer or brake safely, making chemical suppressants not technically feasible for these sites.

Paving removes the availability of particulate matter during roadway travel and reduces emissions. The type and size of equipment traveling on a paved road can affect the feasibility of paving. For example, at Nucor Steel, some mobile equipment use tracks rather than tires; this equipment is not suitable for travel on paved roads as the roads would be destroyed by the tracks travel. Similarly, paving of haul roads at Kennecott is not feasible due to the vehicle weight of their haul trucks. The haul truck weight exceeds the capabilities of paved roads, which would result in rapid deterioration of the paved road.

12G.5 - <u>Ranking of Individual and Combined Controls:</u>

1. Paved Road with vacuum sweeping and watering
2. Paved Road with sweeping and watering
3. Chemical suppressant and watering
4. Watering

12G.6 - <u>Economic Feasibility:</u>

Basic watering of road base to maintain a 20% opacity level on site and a 10% opacity level at the property boundary is required by UAC R307-309, as such a cost analysis was not performed for basic watering.

Chemical dust suppression is in addition to basic watering, and is costly if haul road traffic does not warrant this additional control. Given the technological challenges at Kennecott in implementing chemical dust suppression, and the limited use of haul roads not already paved at Nucor Steel, this cost analysis was not performed.

Paving a haul road does reduce emissions but the cost is estimated at $500,000 per mile paved. This cost is considered economically infeasible for haul roads that are used infrequently or at sources where roads change frequently.

12G.7 - <u>Evaluation of Findings & Control Selection:</u>

Given the specific conditions for Nucor Steel, additional paving is not technically feasible, and basic watering of road base should be implemented as BACT. Similarly, roads at Kennecott that were feasible to pave have been paved. Other roads are not technically feasible to be paved because large haul trucks are used, which would exceed the weight allowance of the paved surface. In addition, Kennecott moves haul roads frequently and so paving roads would not be cost effective.

Given the specific conditions at these two sources, BACT is basic watering of road base to maintain the opacity limits listed in R307-309.

12G.8 - <u>Time for Implementation:</u>

Both new and existing sources should be implementing basic watering to maintain the opacity levels listed in R307-309. Sources that are not should do so immediately.

12I. - Screens

12I.1 - Description:
Screens are used to separate aggregate material according to size by passing undersize material through one or more mesh surfaces in series, and retaining oversize material on the mesh surfaces. Screens are widely used to classify material according to required sizes in various industries including sand and gravel processing operations, coal mining and salt processing operations. NSPS Subpart OOO has a list of nonmetallic minerals, which can be processed by screens.

12I.2 - Emissions Summary:
In aggregate processing operations, when material is screened, it usually carries moisture from prior processing; therefore, emissions from the screening operations are small. Factors affecting emissions include the size of material to be processed, the surface moisture content, the throughput rate, operating practices used, topographical and climatic/seasonal conditions. Annual emissions are usually calculated using the throughput rate in tons per year multiplied by the emission factor in AP-42 Table 11.19.2-2 (USEPA, 2004). Emission factors for $PM_{2.5}$ are limited. The table provides emission factor for screening operation under controlled condition (0.000050 lbs/ton). In order to obtain the uncontrolled emission factor, it is assumed that control efficiencies for PM_{10} and $PM_{2.5}$ are the same. This results in 0.00059 lbs/ton uncontrolled emission factor. For a screen that processes 1 million tons of aggregate material, the uncontrolled $PM_{2.5}$ emissions are calculated at 0.30 tpy

12I.3 - Control Options:
Available control technologies for screening operations include water application, enclosures and add-on control devices such as baghouses, wet scrubbers, cyclones, and electrostatic precipitators. Water application and enclosures are typically used where fugitive particulate emissions are generated.

For screens operating in a $PM_{2.5}$ nonattainment area, the UAC requires visible emissions from screens not to exceed 7% opacity on site (R307-312-4). NSPS Subpart OOO has the same opacity requirement for screens manufactured on or after April 22, 2008.

12I.4 - Technological Feasibility:
All above listed control technologies can provide controls for $PM_{2.5}$ emissions.

12I.5 - Ranking of Individual and Combined Controls:
1. Total enclosures can provide near 100% control for $PM_{2.5}$ emissions.
2. Baghouse and electrostatic precipitators offer high control efficiency (99.9%).
3. Wet scrubbers can control particulate matter at 95% efficiency.
4. Water application can prevent particulate emissions with 92% efficiency, and is widely used in aggregate processing operations.
5. Cyclones control coarse particulate matter very well, but cannot remove fine particles effectively. $PM_{2.5}$ controls using cyclones are estimated at less than 10% efficient.

See the AP-42 section referenced in "Emission Summary". Additional reference can be found in Chapter 3 of Air Pollution Engineering Manual (Air & Waste Management Association, 1992).

12I.6 - Economic Feasibility:

For a screen to process 1 million tons of aggregate material, 0.30 tons of $PM_{2.5}$ would be produced. Control costs include purchased equipment cost, direct installation costs, and indirect installation costs, in addition to costs for site preparation. On an annual basis, these costs would total thousands of dollars if not tens of thousands of dollars. For such small emissions, any add-on devices or enclosures are not economically feasible to control $PM_{2.5}$ emissions from screens. Water application has been determined to be economically feasible to control $PM_{2.5}$ emissions from screens.

12I.7 - Evaluation of Findings & Control Selection:

Water application is selected as the BACT for screens. Water application shall be used to maintain visible emissions not to exceed opacity limits in the UAC as mentioned above.

12I.8 - Time for Implementation:

The current UAC requires screens to have water application and meet the opacity limits above. New sources are required to meet these limits upon startup, and existing sources must currently meet these limits.

12J. - Storage Piles

12J.1 - Description:

Operations in any mining operation inherently have outdoor storage piles. Storage piles are generally uncovered, usually due to frequency of disturbance and use of materials stored.

Dust emissions are common at storage piles and happen over many different life cycles of a storage pile, such as material loading and unloading as well as climate disturbance.

12J.2 - Emissions Summary:

PM emissions are calculated using the equation below (Buonicore, 1992):

$$EF\left(\frac{lb}{(acre)(day)}\right) = 1.7 \times \left(\frac{s}{1.5}\right) \times \left(\frac{365-p}{235}\right) \times \left(\frac{f}{15}\right)$$

Where:

- EF: Total suspended particulate emission factor
- s: Silt Content of Material (5) – (from AP-42 Table 12.3.4-1)
- p: Number of days with greater than 0.01 inches of precipitation per year – (from AP-42 Figure 13.2.1-2)
    - assumed p for SLC, International Airport is = 90
- f: % of time unobstructed wind speed exceeds 12 mph at mean pile height
    - f for SLC, International Airport is = 18.2 ("Station Graph - Salt Lake City Intl Ap Utah," n.d.)

Emission Factors:

PM_{10} = $EF \times 0.85 \left(\frac{lb}{(acre)(day)}\right)$

*Estimated to be 85% of TSP emission factor ("appb-2.pdf," n.d.)

$PM_{2.5}$ = $EF \times 0.30 \left(\frac{lb}{(acre)(day)}\right)$

*Estimated to be 30% of TSP emission factor ("appb-2.pdf," n.d.)

12J.3 - Control Options:

- Water Sprays
- Full Enclosure
- Partial Enclosure

12J.4 - Technological Feasibility:

Watering storage piles is required by R307-309, and it is required for sand and gravel sources to maintain an opacity limit of no more than 20%. Maintaining opacity below 20% is accomplished by the use of water sprays and maintenance on the system.

Full enclosures around storage piles are generally implemented at coal processing plants or other sources where the end product should not be moistened. The sources that implement enclosures to control fugitive emissions generally operate with minimal storage piles so enclosure size can remain small. For all other sources, it is not practically feasible as even small sand and gravel operations generally have 10 or more acres of storage piles, and enclosing that area becomes costly and difficult to implement.

Partial enclosures are easier to implement that full enclosures but are still costly; generally, in order to maintain a 20% opacity limit, water sprays are still required. In very windy areas, barriers can be installed to reduce the impact of wind on storage piles, which could be considered a partial enclosure. Partial enclosures are not common as they are costly and generally do not provide reduced emissions over that of water sprays.

12J.5 - <u>Ranking of Individual and Combined Controls:</u>

1. Full Enclosure
2. Partial Enclosure & Water Sprays
3. Water Sprays

12J.6 - <u>Economic Feasibility:</u>

Full enclosures for large areas are costly, a steel I-beam building enclosing an acre can cost around $7.50 a square foot, (Conrad Mackie, n.d.) resulting in a building cost per acre of enclosure to be roughly $326,700. Given that average uncontrolled $PM_{2.5}$ emissions from one acre of storage piles is 0.08 tons annually, the cost per ton removed, assuming 100% control, would be $4,083,750, making this economically infeasible.

Water systems designed to spray storage piles are built from readily available parts, that are cheap to obtain and the system can be modified easily to maintain a 20% opacity limit. The DAQ assumes a 75% control efficiency of fugitive emissions when water sprays are maintaining the opacity limit; this results in an average controlled $PM_{2.5}$ emission rate of 0.015 tons per acre of storage pile. This control technology is commonly implemented with sources; therefore, a detailed cost per ton removed analysis was not performed, as it is commonly implemented and is considered common practice in most industries, where the material does not need to be kept dry.

Partial enclosures are not common, except where windy conditions are present. They are coupled with water sprays and are used to maintain a 20% opacity limit. A detailed cost analysis was not performed based on technically impracticality.

12J.7 - <u>Evaluation of Findings & Control Selection:</u>

The control option that is technically feasible, and economically viable is the use of water sprays to control fugitive emissions from storage piles. The use of water sprays is considered common practice.

Full enclosures was eliminated due to the economic burden it would place on sources for a very minimal reduction in $PM_{2.5}$ emissions. Similarly, the practicality of partial enclosures was also eliminated, as the Wasatch Front is not considered a windy area, and any enclosure would be coupled with water sprays to maintain an opacity limit of 20% and would be redundant.

12J.8 - <u>Time for Implementation:</u>

Water sprays should be in place before operation begins. Existing sources should also already be equipped with water sprays to maintain the required opacity limit.

12K. - Truck Loading

12K.1 - Description:

Trucks are used to transport loose material on site for processing. Front-end loaders (batch operations) and conveyor stackers (continuous operations) are used to load the material onto the trucks. Industries for which this analysis is intended include sand and gravel processing operations, coal mining, primary metal production, and salt processing operations.

12K.2 - Emissions Summary:

Factors affecting emissions include the size of material to be transported, the surface moisture content, the throughput rate, operating practices used, topographical and climatic/seasonal conditions. Annual emissions are usually calculated using the throughput rate in tons per year multiplied by the emission factor in AP-42 Table 13.2.4 (USEPA, 2006). There are three parameters used to calculate the $PM_{2.5}$ emission factor: particle size multiplier (k = 0.053 for $PM_{2.5}$ emissions), mean wind speed (U), and material moisture content (M). For truck loading of 1 million material a year, assuming U = 7 miles/hr and material moisture content M = 4%, the uncontrolled $PM_{2.5}$ emission is estimated at 0.05 tpy.

12K.3 - Control Options:

Available control technologies for truck loading operations include water application, enclosures and add-on control devices such as baghouses, wet scrubbers, cyclones, and electrostatic precipitators. Water application and enclosures are typically used where fugitive particulate emissions are generated. In order to minimize wind effect, the drop distance should also be minimized to reduce $PM_{2.5}$ emissions.

For truck loading operations in a $PM_{2.5}$ nonattainment area, the UAC requires visible emissions from truck loading and other fugitive dust sources to not exceed 20% opacity on site and 10% opacity at the property boundary (R307-309-5).

12K.4 - Technological Feasibility:

All above listed control technologies can provide controls for PM2.5 emissions.

12K.5 - Ranking of Individual and Combined Controls:

1. Total enclosures can provide near 100% control for $PM_{2.5}$ emissions.
2. Baghouse and electrostatic precipitators offer high control efficiency (99.9%).
3. Wet scrubbers can control particulate matter at 95% efficiency.
4. Water application and minimizing drop distance can be used at the same time to control $PM_{2.5}$ emissions from truck loading.
5. Water application can effectively prevent particulate emissions. Moisture content increase from 4 to 5% in the material will reduce $PM_{2.5}$ emissions by 27% for the conditions mentioned above.
6. Cyclones control coarse particulate matter very well, but cannot remove fine particles effectively. $PM_{2.5}$ controls using cyclones are estimated at less than 10% efficient.
7. Reducing drop distance will help minimize the wind effect and thus reduce $PM_{2.5}$ emissions.

See the AP-42 section referenced in "Emission Summary". Additional reference can be found in Chapter 3 of Air Pollution Engineering Manual (Air & Waste Management Association, 1992).

12K.6 - Economic Feasibility:

For truck loading of 1 million tons of material, 0.05 tons of $PM_{2.5}$ will be produced. Control costs include purchased equipment cost, direct installation costs, and indirect installation costs, in addition to costs for site preparation. On an annual basis, these costs would total thousands of dollars if not tens of thousands of dollars. For such small emissions, any add-on devices or enclosures are not economically feasible to control PM2.5 emissions from truck loading operations. Water application and minimizing drop distance have been determined to be economically feasible to control $PM_{2.5}$ emissions from truck loading operations.

12K.7 - Evaluation of Findings & Control Selection:

Water application and minimizing drop distance are selected as the BACT for truck loading operations. Both methods shall be used to maintain visible emissions not to exceed opacity limits in the UAC mentioned above.

12K.8 - Time for Implementation:

The current UAC requires that truck loading operations and other sources of fugitive dust meet the opacity limits above. New sources are required to meet these limits upon startup, and existing sources must currently meet these limits.

13. - Storage Tanks

13.1 - Description:

This section includes various types of storage tanks. The storage tanks in this section store various liquids that contain VOC.

13A. - Fuel Oil Storage Tanks < 30,000 Gallons

13A.1 - Description:
Fuel oil storage tanks are fixed roof tanks of various sizes, for this analysis a maximum size of 30,000 gallons was used. Storage tanks have the potential to emit VOC and HAP emissions from loading and unloading the tank, as well as working and breathing losses associated with temperature changes in the fuel oil being stored.

13A.2 - Emissions Summary:
Fuel oil is considered a non-volatile liquid. ("c05s02.pdf," n.d.)

A tank run was made using EPA Tanks 4.09d, and Distillate Fuel Oil No. 2. The tank run estimated annual VOC emissions of 27.73 lbs/year from a 30,000-gallon storage tank assuming 12 turnovers per year.

13A.3 - Control Options:
- Submerged Fill Pipes
- Vapor Control System

13A.4 - Technological Feasibility:
Submerged fill pipes consists of hard pipes installed to the inlet of the storage tank that extend to no more than six inches above the bottom of the tank, or six inches above the maximum drain level of the tank. This ensures that when filling the tank a physical drop of no more than six inches occurs, which reduces and quickly eliminates VOC emissions associated with splash loading. This extension of hard pipe is easily installed on a storage tank.

Vapor control systems have many forms, they are designed to either capture and recycle or capture and destroy vapor emissions from storage tanks. Many options exist, and most are technologically feasible when controlling emissions from fixed storage tanks.

13A.5 - Ranking of Individual and Combined Controls:
1. Vapor Control System
2. Submerged Fill Pipes

13A.6 - Economic Feasibility:
Based on the very limited emissions from fuel oil storage tanks economic feasibility cannot be extended beyond the use of submerged fill pipes. These pipes consist of nothing more than an extension, in most cases less than 20 feet of hard piping. The piping is inexpensive and easy to implement.

Economic feasibility was not evaluated for vapor control systems as the VOC emissions associated with fuel oil storage tanks are less than 30 pounds annually. With the limited amount of VOC emissions, the costs associated with vapor control systems are cost prohibitive.

13A.7 - Evaluation of Findings & Control Selection:

Due to the minimal emissions associated with fuel oil storage tanks the only option that is feasible would be the use of submerged fill pipes. This is considered to be BACT for controlling fuel oil storage tanks less than 30,000 gallons.

13A.8 - Time for Implementation:

New sources should have a submerged fill pipe installed prior to accepting fuel oil. For existing sources, minimal equipment is required, and sources can easily retrofit existing tanks. Implementation should occur as soon as possible if not already operating a submerged fill pipe.

13B. - Gasoline Fueling

13B.1 - Description:

Gasoline fueling can emit VOC and HAP emissions when the vehicles fuel tank is filled. The displaced air volume within the tank is laden with VOC and HAP emissions that are vented to the atmosphere.

13B.2 - Emissions Summary:

VOC emissions from loading operations of gasoline with an RVP of 10 are 10 lbs/1,000-gallons. (“c05s02.pdf,” n.d.)

13B.3 - Control Options:

- Stage I Vapor Recovery
- Stage II Vapor Recovery

13B.4 - Technological Feasibility:

40 CFR 63 Subpart CCCCCC applies to Gasoline Dispensing Facilities as defined in §63.11132. This subpart requires specific operational and maintenance constraints that limit the emissions from these sources. For smaller operations, below 10,000 gallons a month, it requires the minimization of gasoline spills, prompt cleanup and closing and sealing containers. For sources that have throughputs higher than 10,000 gallons a month, it requires submerged fill tubes, as well as the operational requirements listed above. For sources operating above 100,000 gallons a month, the previous conditions need to be met as well as specific vapor balance system conditions.

Stage I vapor recovery consists of a vapor capture line that connects to the tanker truck delivering fuel to a storage vessel. The vapor capture lines efficiencies can fall into one of three categories: 99.2%, 98.7%, or 70%. The type of inspection being performed annually on the system results in the level of capture efficiency, a MACT-level leak test, NSPS-level leak test, or no leak test respectively (“c05s02.pdf,” n.d.). This control strategy prevents vapors from being emitted to the atmosphere by recycling the vapors from the tanker truck or storage vessel, whichever is being loaded, into the other, which is being emptied. This control strategy is common practice in gasoline fueling operations.

Stage II vapor recovery consist of a vapor capture line for vehicle fuel tanks, this involves a special vapor capture fill nozzle that allows VOC emission to enter the storage vessel as they are expelled from the vehicles fuel tank. The equipment required to install a stage II vapor system would not require anything different at a site, aside from the additional capture fill nozzle and associated piping, and would be feasible as a control strategy for filling individual fuel tanks from the storage vessel.

13B.5 - Ranking of Individual and Combined Controls:

1. Stage I and Stage II Vapor Recovery
2. Stage I Vapor Recovery
3. Stage II Vapor Recovery

13B.6 - Economic Feasibility:

Stage I vapor recovery is inexpensive to implement, as it only requires a collection of pipes and hoses. The ability to control emissions from the loading of a storage vessel, when the largest displacement of air volume occurs, results in the largest VOC emission reductions. The control of gasoline fueling is advantageous, and economically viable due to the limited equipment required.

The tanker truck testing protocol costs a fee per tanker truck, a fee of $35 ("Doc_0168_VOC250512811.pdf," n.d.). However, the maintenance on the tanker truck to maintain the MACT or NSPS leak threshold can be expensive and needs to be performed on a regular basis. The tanker truck, in most cases, is inspected monthly to monitor for leaks; this maintenance regime can be costly and expensive for smaller operators.

Stage II Vapor recovery is not required by any federal regulations, Ohio and California have incorporated this control strategy for large gasoline dispensing sources located in nonattainment areas. As this document is meant to address gasoline fueling for smaller sources where emissions are minimal, the assumption is that it is too costly to implement a stage II vapor recovery system.

13B.7 - Evaluation of Findings & Control Selection:

Stage I recovery systems are both economically and technically feasible to implement for controlling VOC emissions from gasoline fueling operations. Due to the truck maintenance required to keep them in working order to pass either a MACT or NSPS level vacuum test, this testing is not economically feasible. A 70% control efficiency is still achievable with no testing and was selected as BACT for sources that have gasoline fueling operations.

Stage II recovery systems are not economically feasible.

13B.8 - Time for Implementation:

Given the limited amount of equipment required to implement stage I vapor recovery (pipes and hoses) equipment should be easily attainable and will not require a shutdown to install. Existing sources should be given 180 days to implement this control strategy. New sources should have equipment in place prior to operation.

13C. - Underground Fuel Storage Tanks

13C.1 - Description:

Storage tanks can be buried to minimize weather erosion of the tank as well as insulate the tank from thermal changes, which help reduce emissions. Underground storage tanks are usually horizontal tanks.

13C.2 - Emissions Summary:

Emissions from underground storage tanks occur during tank loading operations and from working losses, changes in liquid level within the tank; breathing losses do not occur in underground storage tanks as temperature changes are minimal due to the insulating nature of the surrounding earth (Tanks, 2006).

A tank run was made using EPA Tanks 4.09d, and Gasoline RVP 10. The tank run estimated total uncontrolled annual emissions of 2.06 tons, assuming a 25,000 gallon storage tank with 24 turnovers annually.

VOC emissions from loading operations of gasoline with an RVP of 10 are 10 lbs/1,000-gallons ("c05s02.pdf," n.d.).

13C.3 - Control Options:

- Loading Operations
    - Submerged Loading
    - Vapor Return – Open System
    - Vapor Return – Closed System
- Working Losses
    - Closed Vent System
        - Combustion Device

13C.4 - Technological Feasibility:

- Loading Operations
    - Submerged Loading: 40 CFR 63 Subpart BBBBBB applies to sources that have storage tanks larger than 250 gallons, and requires that loading of storage tanks must be performed using submerged loading. This is a federal requirement; therefore, it is assumed that all underground storage tanks must implement submerged loading. This technology is required in most states and is considered common practice.
    - Vapor Return – Open System: A vapor return system captures vapors during the truck loading and unloading operations and routes them back to the underground storage tank or tanker truck. An open system captures what it can and what it doesn't capture vents to the atmosphere. Capture efficiencies fall into one of three categories: 99.2%, 98.7%, or 70%. The type of inspection being performed annually on the system, a MACT-level leak test, NSPS-level leak test, or no leak test determines the capture efficiency ("c05s02.pdf," n.d.). This is referred to in

    - the gasoline fueling industry as stage I vapor recovery, and is easily accomplished.
    - Vapor Return – Closed System: A closed system tied to a vapor return line means that the line is routed to some sort of vapor recovery equipment, captures vapors and returns them to liquid form to be sent back to the product storage, or routes them to a combustion device.
- Working Losses
    - Closed Vent System: A closed vent system is designed to capture and either recovers and returns the lost vapors to the storage tank or destroys them. Recovery occurs through the use of refrigeration, absorption, adsorption, compression, or a combination of one or more of the previously mentioned methods. Destruction is achieved through a combustion device.
        - A closed vent system is required for the use of a combustion device to control tank vapors. A combustion device destroys tank vapors through thermal oxidation.

13C.5 - <u>Ranking of Individual and Combined Controls:</u>

1. Vapor Return – Closed System
2. Vapor Return – Open System
3. Submerged Loading

13C.6 - <u>Economic Feasibility:</u>

A closed vapor return system is expensive to implement; however, the vapor return line tied to the tank and the tanker truck is not expensive, but the vapor recovery or destruction is costly. A combustion device is cheaper than a vapor recovery system in both initial cost and operational costs. The initial investment for a small enclosed combustion device can cost $40,000 – $85,000, with operational costs adding another ~$20,000 annually. For the amount of pollution controlled, a combustion device is not economically feasible.

The costs associated with operating a vapor return line that is open to the atmosphere is fairly cheap, as it only requires additional piping, and has the capability to control 99.2% of emissions given it passes the MACT level testing annually. With no testing on the tanker truck system, a control efficiency of 70% is achieved for the minimal cost of additional piping. A source implementing an open vapor return system with a throughput of 250,000 gallons can reduce their emissions from 1.26 tons to 0.38 tons annually by nothing more than the addition of piping to the site.

Submerged loading operations would control the truck loading operations, but do nothing for the working losses associated with the fluctuation in tank volume over time. Federal Regulation 40 CFR 63 Subpart BBBBBB requires submerged loading, and as such a cost analysis was not performed.

13C.7 - <u>Evaluation of Findings & Control Selection:</u>

Given the limited costs of installing a vapor return line, and its capability of controlling at least 70% of tank loading emissions, this was selected as BACT due to economic and technological feasibility for sources over 250,000 gallons of throughput annually. If a source has an annual throughput of less than 250,000 gallons the emissions controlled would be less than one ton, and as such may become burdensome based on limited use, and submerged loading should be considered BACT.

13C.8 - Time for Implementation:

Given that additional piping is all that is required for the implementation of a vapor return line, and that this can be done without taking the source off line, existing sources should have a 180-day period to install the required equipment. New sources should have this equipment in place prior to operation.

14. - Vacuum Cleaning System (Industrial)

14.1 - Description:

Industrial central vacuum cleaning systems use suction to remove site-wide dust and waste. Systems can be implemented to assist with removal of PM_{10} and $PM_{2.5}$-laden air at a source. The vacuum system draws air in and carries site-wide dust and particles into a filter-filled chamber (Stefan, 2013). These filters range from small filter systems to large systems that can incorporate cyclones and baghouses ("Industrial central vacuum systems for dust control and housekeeping," 2017). Vacuum system differences can be attributed to source size and industry.

Air emissions are generated as filtered air exits the system with a small portion of pollutants. System emission points can vent inside or outside of the building, dependent on the system size, source operations, and operating industry.

Vacuum systems vary in size and capacity based on the needs of the source. Systems can vary from 400 CFM to 7450 CFM with multiple functions across source types ("Stationary Industrial Vacuum Loader," 2016). All systems use, at minimum, standard High Efficiency Particulate Air (HEPA) filter systems with a 99.97% retention rate for particles lager than 0.3 microns ("Types of Filters," 2017). Larger systems use baghouses with a 99% control efficiency for PM_{10} and $PM_{2.5}$.

The functionality of all vacuum systems is dependent on suction and filtration. To ensure that the system maintains effective controls proper maintenance and repair must be practiced.

14.2 - Emissions Summary:

Emissions from the vacuum system are emitted as the airflow exists the control chamber. Most PM_{10} is captured by all system types. $PM_{2.5}$ is not captured by HEPA filters. Systems operating with HEPA filters can emit approximately 0.03% of the PM_{10} and 100% of the $PM_{2.5}$ that enters the system. The amount of particulate matter captured depends on the particle size distribution of the particles entering the filter system.

14.3 - Control Options:

There are no federal air quality regulations that apply to this activity. The State of Utah does not have any specific regulations for central vacuum systems.

The RBLC yielded no additional control options for central vacuum systems.

Industry standard filters have a rating of 99.97% for PM_{10} but zero retention for $PM_{2.5}$. Ultra-Low Penetration Air (ULPA) have a 99.99% rating for particles greater than 0.12 microns ("Types of Filters," 2017). Changing filters is a viable option for increasing pollution control.

Proper operation, maintenance, and repair of systems ensure the effectiveness of the system.

14.4 - Technological Feasibility:

HEPA filters and ULPA filters were designed to be interchangeable. There are no technical restrictions to implementing more efficient system filters. Baghouses are already implemented on existing vacuum filter systems. Control options are dependent on the site operations.

14.5 - Ranking of Individual and Combined Controls:

The best control option is dependent on source's operations and needs. For some smaller systems using HEPA filters, ULPA filters could be a better, more efficient, control option. Baghouses are appropriate for large operations venting to the ambient atmosphere. For all systems, proper operation and maintenance is crucial for the operation of the system.

14.6 - Economic Feasibility:

The feasibility of each control is dependent on source operations, functions, and design. Each case requires individual analysis of vacuum system controls.

14.7 - Evaluation of Findings & Control Selection:

Sources operating vacuum systems should evaluate all possible control options for their site. All sources should follow the manufacturer's instructions for operation, maintenance, and repair.

14.8 - Time for Implementation:

All sources should maintain systems according to the manufacturer. Existing and future systems should evaluate all possible control measures for their system to determine BACT.

15. - Wastewater Treatment Plants

15.1 - Description:

This source category is for several specific point sources in Utah, all at the ATK plant. This source category is for the wastewater treatment plants that are located at the ATK plant.

15.2 - Emissions Summary:

This source category is capable of emitting VOC, a $PM_{2.5}$ precursor pollutant. The maximum PTE for this source is 5.4 tons per year of VOC emissions. This is based on a permit limitation for one of the point sources. Emissions from this source category are determined using a mass balance method dependent on the percentage of VOC in each material.

15.3 - Control Options:

The following sources were reviewed to identify available control technologies:

- EPA's RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA's Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state and federal regulations
- Various state-specific example permits
- A thorough literature search using the Google search engine

Control Options for VOC:

- Carbon Adsorbers (United States Environmental Protection Agency, 1992)
- Thermal Vapor Incinerators (US EPA, 1992)
- Catalytic Vapor Incinerators (US EPA, 1992)
- Flares (US EPA, 1992)
- Boilers and Process Heaters (US EPA, 1992)
- Condensers (US EPA, 1992)
- Biofiltration (Envirogen Technologies, n.d.)

15.4 - Technological Feasibility:

Control Options for VOC:

Carbon Adsorbers

There are two types of carbon adsorbers – fixed bed carbon adsorbers and carbon canister adsorbers. Fixed bed carbon adsorbers are used for controlling continuous, large gas streams with flow rates ranging from 30 to 3,000 m^3/minute (US EPA, 1992). Based on the maximum PTE of 5.4 tpy of VOC emissions and the density of one of the components of the wastewater, isopropyl alcohol, the gas stream flow rate for this source category is far below the gas stream flow rate a fixed bed carbon adsorber can be sized for. Therefore, this control option is not technologically feasible for this source category. Carbon canister adsorption can be used to control low flow gas streams. Therefore, carbon canister adsorption is technologically feasible for this source category.

Thermal Vapor Incinerators
Thermal vapor incinerators are typically sized to handle gas stream flow rates ranging from 8 to 1,400 m^3/minute (US EPA, 1992). Based on the maximum PTE of 5.4 tpy of VOC emissions and the density of one of the components of the wastewater, isopropyl alcohol, the gas stream flow rate for this source category is far below the gas stream flow rate a thermal vapor incinerator can be sized for. Therefore, this control option is not technologically feasible for this source category.

Catalytic Vapor Incinerators
Catalytic vapor incinerators are typically operated at temperatures in the range of 600 – 1,200 °F. Temperatures below this range result in low destruction efficiencies (US EPA, 1992). This source category is for industrial wastewater treatment processes that will not be at such a high operating temperature; therefore, this is not a technologically feasible control option.

Flares
Flares can be used for almost any VOC stream, and can handle fluctuations in VOC concentration, flow rate, and inerts' content (US EPA, 1993). Therefore, the use of a flare is a technologically feasible control option for this source category.

Boilers and Process Heaters
This control option would require the source to install process equipment that might not be necessary for the source. This is not a technologically feasible option because there is no way of knowing if the source requires process boilers and heaters, and the gas stream flow rate is quite low to be usable. Therefore, this is not technologically feasible.

Condensers
Condensers can be used for any organic compound, dependent on the organic compound chemical properties (US EPA, 1992). However, condensers are not effective for gas streams containing low organic concentrations (United States Environmental Protection Agency, 1990). Therefore, this is not a technologically feasible control option.

Biofiltration
Envirogen Technologies provides biofilters for odor control and VOC treatment for installation at wastewater treatment plants; therefore, this is a technologically feasible control option for this source category (Envirogen Technologies, n.d.).

15.5 - <u>Ranking of Individual and Combined Controls:</u>

1. Flares: Up to 98% control efficiency (US EPA, 1992)
2. Carbon Adsorbers: Up to 95% control efficiency for carbon canister adsorption system (US EPA, 1992)
3. Biofiltration: Up to 90% control efficiency (Gero Leson & Arthur M. Winer, 1991)

15.6 - Economic Feasibility:

Control Options for VOC:

1. Flares: According to Table 5-6 in "Control of Volatile Organic Compound Emissions from Reactor Processes and Distillation Operations Processes in the Synthetic Organic Chemical Manufacturing Industry" on Page 5-16, the cost effectiveness of a low inlet gas stream flow rate is $6,638 per Mg removed, which is approximately $6,021 per ton removed of VOC in 1993 dollars. This is approximately $10,189 in 2017 dollars. Therefore, this is not an economically feasible control option for this source category.
2. Carbon Adsorbers: The capital and operating costs for a carbon adsorber have been estimated assuming a capital cost of $100,000, an annual interest rate of 7% (US EPA, 2002), an economic life of a unit at approximately 20 years, and annual operating and maintenance costs of $315,800 (Ken Corey & Leo Zappa, n.d.). Using these factors, the cost/ton removed for installing a carbon adsorber system is $63,000. Therefore, this control option is not economically feasible.
3. Biofiltration: The capital and operating costs for a biofiltration system have been estimated assuming a capital cost of $355,000, an annual interest rate of 7% (US EPA, 2002), an economic life of a unit at approximately 20 years, and annual operating and maintenance costs of $65,000 (Ken Corey & Leo Zappa, n.d.). Using these factors, the cost/ton removed for installing a biofiltration system is $18,773. Therefore, this control option is not economically feasible.

15.7 - Evaluation of Findings & Control Selection:

The DAQ recommends the following as BACT: proper operation and maintenance of wastewater treatment process equipment, and the minimization of VOC emissions through covering of process equipment where feasible.

15.8 - Time for Implementation:

The proper operation and maintenance of the wastewater treatment process equipment should be ongoing; the DAQ does not anticipate additional time for implementation as necessary.

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