Addendum to the Application to Revise Minor Permit AQ0307MSS04

for

United States Air Force

Eareckson Air Station

Submitted To:

Alaska Department of Environmental Conservation
Division of Air Quality, Air Permits Program

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1.0 Introduction

The United States Air Force (USAF) Eareckson Air Station (Eareckson) is requesting an additional change to Minor Permit AQ0307MSS04 that will remove the Owner Requested Limits (ORLs) on the emergency engines by revoking Condition 12 in its entirety from the permit. This request will not increase the Potential to Emit (PTE) for the engines, but will remove the extraneous monitoring, recordkeeping, and reporting (MR&R) associated with this condition. This request is being submitted under 18 AAC 50.508(6).

Condition 12 of AQ0307MSS04 was originally established in AQ0307CP01, which was issued in 2003 as part of the Department's effort to conduct Prevention of Significant Deterioration (PSD) "look back" evaluations on numerous projects that spanned from 1988 to 2003. Over the course of years, some of the engines originally included in the ORLs have been removed and some have been replaced. In several iterations this condition has been carried forward from minor permit to minor permit to its present form today in AQ0307MSS04 Condition 12.

The engine operating hour limits were established in the CP01 permit to cap the PTE from numerous emergency engines, a practice that at that time was regarded as necessary but is no longer regarded as such by the Department today. The TAR for CP01 indicates that some of the engines limited by the ORLs were included in "Project 1" and some were included in "Project 2." These were installations and/or replacements of engines that occurred at different junctures during that time frame. Because "Project 2" had a net increase in emissions that triggered a PSD Major Modification, modeling was conducted. The contribution from the emergency engines, capped by each respective operating hour limit, was included in the modeling demonstration in 2003.

Revoking the ORLs will not change any permit classifications, nor impact underlying ambient air quality analyses, nor cause any substantial changes in the facility's potential to emit (PTE). This request is being submitted under 18 AAC 50.508(6) to revise the terms or conditions of a Title I permit. All information required under 18 AAC 50.540(b) and (k) is included within this application.

This addendum is being submitted to augment a prior application submitted in July 2020. Consistent with the previous application, this application includes a request to incorporate the revisions into the Title V permit through contemporaneous review of the minor permit and the Title V operating permit.

2.0 Minor Permit (Title I) Revision Application Requirements

As required by 18 AAC 50.540(b), the Stationary Source Identification Form (SSID) is included in the original application. No new SSID form is included in this request.

In accordance with §50.540(k)(1), a copy of the Title I permit that established the permit terms and conditions that are proposed for revision is provided in the original application. No new copy of the minor permit is included in this addendum.

The remaining permit requirements listed under §50.540(k)(2)-(4) are addressed below.

2.1 Reason for the Request

In accordance with §50.540(k)(2), this change will reduce the burden of MR&R associated with this condition, without producing any environmental risk or changing the permit classification. The request aligns the treatment of this facility's emergency engines with emergency engines across the milieux of facilities in Alaska by acknowledging the regulatory framework for handling emergency engines that is in place today.

Emergency engines are not physically designed for continual operation. EPA has long acknowledged that short-term operation is a component of the physical and operational design of an emergency engine. Likewise, ADEC has long accepted the guidance from EPA on the calculation of emergency engine PTE. EPA states in a 1995 memorandum (Attachment A):

> The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions. Alternative estimates can be made on a case-by-case basis where justified by the source owner or permitting authority (for example, if historical data on local power outages indicate that a larger or smaller number would be appropriate).

More recently, EPA has promulgated regulations that further limit the operation of emergency engines for non-emergency purposes, specifically in the context of the New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines [(40 CFR 60.4211(f)] and the National Emission Standards for Hazardous Air Pollutants (NESHAP) for [40 CFR 63.6640(f)]. These regulations mirror one another, and can be summarized as follows:

- There is no limit to emergency operations,
- Maintenance and readiness checks are limited to 100 hours per year, and
- Other non-emergency operations can occur up to 50 hours per year, but those hours count toward the 100 hour annual total stated above.

This produces a federally enforceable limit on emergency engine operation for non-emergency purposes that did not exist in 2003 and compels the USAF to monitor and record the operating hours and nature of the operation (i.e.: emergency, maintenance/readiness, non-emergency) in accordance with these rules, as applicable. The USAF complies with these monitoring and recordkeeping obligations and will continue to do so after Condition 12 is revoked.

New emergency engines certified by the engine manufacturer must bear a permanent label identifying them as emergency engines, per 40 CFR 60.4210(f). This is another enforceable regulatory requirement that distinguishes emergency engines from non-emergency engines. Such labels are found on new, EPA certified emergency engines.

2.2 Effect on Emissions

In accordance with §50.540(k)(3)(a), there will be a small reduction in most criteria pollutant emissions from the emergency engines listed in Condition 12, compared to the corresponding PTE from the same emergency engines included in the 2003 PSD "look back" project.

NOx emissions increase by 0.75 TPY. Of this, 0.6 TPY of the NOx emissions increase is attributable to the replacement of EU IDs 50 and 51 with 50a and 51a which occurred in 2017. This net increase should be treated as a separate project from the 2003 "look back" project. The remaining increase is attributable to more accurate engine capacity information that resulted from a 2019 facility-wide EU inventory inspection. The NOx emissions increase shown here does not cause the 2003 "look back" project to be reclassified for PSD permitting. This project was already significant for NOx at that time, and PSD review was conducted.

Table 1, below, presents the PTE for each engine subject to an ORL as given in the TAR to AQ0307CP01 Exhibit A. For ease of reference, the TAR to AQ0307CP01 is included in Attachment B. Table 1 data is derived from Schedule A-1 of that document.

Table 2 presents the current PTE from the engines identified in AQ0307MSS04, Condition 12. The emission calculations conservatively assume the number of operating hours on all EUs remains the same as the ORLs in Condition 12, except for EU IDs 13 and 14. This application assumes 500 hours of operation on EU IDs 13 and 14 because the ORL of 1,000 hours far exceeds the expected annual operation for these engines. The actual operations of all emergency engines in this facility are demonstrably lower than the assumed PTE values presented in Table 2. Emergency engine operating data for each of the engines listed in Condition 12 is presented in Attachment C. These data include operating hours for all ORL emergency engines from 2020, 2021, and 2022, as reported to the Department in recent Facility Operating Reports. Detailed emission calculations are included with this submittal in the attached MS Excel™ spreadsheet (Attachment D).

For applying the State Emission Standards for visible emissions (VE) and particulate matter (PM), all emergency engines are below the significance thresholds based on their PTE, except EU IDs 32, 33, 36 and 42, which are significant for NOx based on their PTE. However, they are insignificant based on their actual emissions, and thus will certify compliance with the emissions standards in the annual compliance certification required by the Title V operating permit, as described in Standard Permit Condition IX.

Table 1: Summary of Emissions from the TAR to AQ0307CP01, Exhibit A, Tables A1

EU ID	Bldg.	Op. Hr. Limit	Install Date	Rating	PM-10	SO_2	NOx	CO	VOC
13	3057	1000	10/1988	186 hp	0.2	0.2	2.9	0.6	0.2
14	3057	1000	10/1988	230 hp	0.3	0.3	3.6	0.8	0.3
15	4011	500	1/1997	175 hp	0.1	0.1	1.4	0.3	0.1
16	3049	500	10/2003	160 hp	0.1	0.1	1.2	0.3	0.1
17	3049	500	10/2003	160 hp	0.1	0.1	1.2	0.3	0.1
27	76-558	500	1/1987	40 kW	0.0	0.0	0.4	0.1	0.0
30	3049-7	300	1/1990	225 kW	0.1	0.1	1.4	0.3	0.1
32	4014-1	300	1/1991	350 kW	0.2	0.2	2.2	0.5	0.2
33	4014-2	300	1/1991	350 kW	0.2	0.2	2.2	0.5	0.2
34	600	300	1/1991	283 kW	0.1	0.1	1.8	0.4	0.1
35	609	500	1/1995	100 kW	0.1	0.1	1.0	0.2	0.1
36	754	300	1995	400 kW	0.2	0.2	2.5	0.5	0.2
40	628	300	1/1998	275 kW	0.1	0.1	1.7	0.4	0.1
41	718	500	1/2000	50 kW	0.0	0.0	0.5	0.1	0.0
42	775	500	1/2001	500 kW	0.1	0.4	4.0	0.9	0.1
50	74-041-1	NA	2005	65.9 hp	0.0	0.0	0.2	7.2	0.4
51	74-041-2	NA	2005	65.9 hp	0.0	0.0	0.2	7.2	0.4
				Total Emissions:	**1.9**	**2.2**	**28.4**	**20.6**	**2.7**

Table 2: Summary of Current Emissions

EU ID	Bldg.	Basis for PTE	Install Date	Rating	PM-10	SO_2	NOx	CO	VOC
13	3057	500	10/1988	188 hp	0.1	0.1	1.5	0.3	0.1
14	3057	500	10/1988	235 hp	0.1	0.1	1.8	0.4	0.1
15	4011	500	2/2005	160 hp	0.1	0.1	1.2	0.3	0.1
16	3052	500	2004	160 hp	0.1	0.1	1.2	0.3	0.1
17	3052	500	2004	160 hp	0.1	0.1	1.2	0.3	0.1
27	76-558	500	1/1987	40 kW	0.0	0.0	0.6	0.1	0.0
30	3049	300	1/1990	248 kW	0.1	0.1	1.5	0.3	0.1
32	4014	300	1/1991	350 kW	0.2	0.2	2.5	0.5	0.2
33	4014	300	1/1991	350 kW	0.2	0.2	2.5	0.5	0.2
34	600	300	1/1991	283 kW	0.1	0.1	1.9	0.4	0.2
35	609	500	1/1995	154 kW	0.1	0.1	1.6	0.3	0.1
36	754	300	1995	496 kW	0.1	0.2	2.4	0.5	0.1
40	628	300	1/1998	302 kW	0.1	0.1	1.9	0.4	0.2
41	718	500	1/2000	76.1 kW	0.1	0.1	0.8	0.2	0.1
42	775	500	1/2001	500 kW	0.2	0.0	5.4	1.2	0.1
50a	74-041-1a	500	3/2017	64 hp	0.0	0.0	0.5	0.1	0.0
51a	74-041-2b	500	3/2017	64 hp	0.0	0.0	0.5	0.1	0.0
				Total Emissions:	**1.74**	**1.66**	**29.15**	**6.39**	**1.91**

Table Notes:
a) Most changes to engine information, shown in red text, are attributable to better recordkeeping.
b) This application assumes that the PTE of EU IDs 13 and 14 is based on 500 hours operation.
c) EU IDs 50 and 51 were replaced with EU IDs 50a and 51a in 2017. NOx emissions increased by 0.6 TPY as a result of this replacement.
d) EU ID 39 is no longer in service.

2.3 Effect on Other Permit Terms and Conditions

In accordance with §50.540(k)(3)(b), the removal of Condition 12 from the minor permit will not impact any other terms or conditions of that permit. There is a parallel condition in the current Title V operating permit AQ0307TVP03 Rev. 2, Condition 15. There will be no other effect on other permit terms and conditions.

2.4 Effect on Ambient Analysis

In accordance with §50.540(k)(3)(c), there will be no significant impact on the ambient air quality analysis performed in 2003 that results from the removal of Condition 12.

The TAR to AQ0307CP01 makes it clear that the contribution of pollutant emissions from emergency engines was included in the ambient air quality analysis performed as a part of "Project 2." The revised PTE calculations presented above demonstrate a reduction in most criteria pollutants, and a *de minimus* increase of NOx emissions. This would not be expected to produce a significant change in the results of that analysis.

2.5 Effect on Compliance Monitoring

In accordance with §50.540(k)(3)(d), the USAF will continue to record operating hours on all emission units, as this information is used for several other air quality-related reasons: assessable emissions estimates, triennial point source emission inventory, NSPS and NESHAP compliance. The data is also used for internal maintenance and operational reasons: ensuring that engine maintenance is conducted in accordance with manufacturer's written instructions and ensuring that equipment is operated in accordance with good engineering practices.

2.6 Permit Classification Changes

In accordance with §50.540(k)(4), revoking Condition 12 will not cause a change in the permit classification. "Project 2" of the PSD "lookback" project was classified as a major modification under PSD, and the facility underwent a full PSD analysis as a result of that project. The underlying assumptions about emergency engine operating hours, which were at that time enshrined in an ORL, are not being relaxed or increased, and the PTE for these engines is not changing significantly as a result of removing the ORL.

After studying the historical basis for this condition, and considering the regulatory framework in place today, we believe that this ORL does not result in a measurable net benefit to the environment. Revoking the ORL will not change the physical and operational design of the engines, nor will it result in any change to the method of operation of this equipment. It will not result in any increase in the operation of the engines above normal routine maintenance and readiness checks and the expected operations that may occur in an emergency. Therefore, removal of this ORL will reduce the burden of monitoring, recordkeeping, and reporting relating to Condition 12 without producing any environmental or regulatory concerns.

3.0 Request for Integrated Review

This application is an addendum to the minor permit modification ADEC is currently preparing. The USAF continues to request that this application be reviewed under the integrated review process described in 18 AAC 50.326(c)(1).

4.0 Application Fees

USAF understands that ADEC will charge fees based upon time and material for review and processing of this request under 18 AAC 50.400(h).

Attachment A:
EPA Seitz Memo 1995

September 6, 1995

MEMORANDUM

SUBJECT: Calculating Potential to Emit (PTE) for Emergency Generators

FROM: John S. Seitz, Director
Office of Air Quality Planning and Standards (MD-10)

TO: Director, Air, Pesticides and Toxics Management Division, Regions I and IV
Director, Air and Waste Management Division, Region II
Director, Air, Radiation and Toxics Division, Region III
Director, Air and Radiation Division, Region V
Director, Air, Pesticides and Toxics Division, Region VI
Director, Air and Toxics Division, Regions VII, VIII, IX, and X

The purpose of this guidance is to address the determination of PTE for emergency electrical generators.

Background

In a memorandum dated January 25, 1995, the Environmental Protection Agency (EPA) addressed a number of issues related to the determination of a source's PTE under section 112 and title V of the Clean Air Act (Act). One of the issues discussed in the memorandum was the term "maximum capacity of a stationary source to emit under its physical and operational design," which is part of the definition of "potential to emit." The memorandum clarified that inherent physical limitations, and operational design features which restrict the potential emissions of individual emission units, can be taken into account. This clarification was intended to address facilities for which the theoretical use of equipment is much higher than could ever actually occur in practice. For such facilities, if their physical limitations or operational design features are not taken into account, the potential emissions could be overestimated and consequently the source owner could be subject to the Act requirements affecting major sources. Although such source owners could in most cases readily accept enforceable limitations restricting the operation to its designed level, EPA believes this administrative requirement for such sources to be unnecessary and burdensome.

On the topic of "physical and operational design," the January 25 memorandum provided a general discussion. In addition, EPA committed to providing technical assistance on the type of inherent physical and operational design features that may be considered acceptable in determining the potential to emit for certain individual small source categories. The EPA is currently conducting category-specific analyses in support of this effort, and hopes as a result of these analyses to generate more general guidance on this issue as well.

The purpose of this memorandum is to address the issue of PTE as it relates specifically to emergency generators. There is a significant level of interest in this source category because there are many thousands of locations for which an emergency generator is the only emitting source. Moreover, based on a review of this source category, there exists a readily identifiable constraint on the operational design of emergency generators. Hence, the EPA believes it would be useful to provide today's guidance before the entire effort is complete.

The policies set forth in this memorandum are intended solely as guidance, do not represent final Agency action, and cannot be relied upon to create any rights enforceable by any party.

Guidance for Emergency Generators

For purposes of today's guidance, an "emergency generator" means a generator whose sole function is to provide back-up power when electric power from the local utility is interrupted. The emission source for such generators is typically a gasoline or diesel-fired engine, but can in some cases include a small gas turbine. Emissions consist primarily of carbon monoxide and nitrogen oxides. Other criteria pollutants, and hazardous air pollutants, are also emitted, but at much lower levels. Emissions occur only during emergency situations (i.e., where electric power from the local utility is interrupted), and for a very short time to perform maintenance checks and operator training.

The EPA believes that generators devoted to emergency uses are clearly constrained in their operation, in the sense that, by definition and design, they are used only during periods where electric power from public utilities is unavailable. Two factors indicate that this constraint is in fact "inherent." First, while the combined period for such power outages during any one year will vary somewhat, an upper bound can be estimated which would never be expected to be exceeded absent extraordinary circumstances. Second, the duration of these outages are entirely beyond the control of the source, and when they do occur (except in the case of a major catastrophe) rarely last more than a day.

For emergency generators, EPA has determined that a reasonable and realistic "worst-case" estimate of the number of hours that power would be expected to be unavailable from the local utility may be considered in identifying the "maximum capacity" of such generators for the purpose of estimating their PTE. Consequently, EPA does not recommend the use of 8760 hours per year (i.e., full-year operation) for calculating the PTE for emergency generators. Instead, EPA recommends that the potential to emit be determined based upon an estimate of the maximum amount of hours the generator could operate, taking into account (1) the number of hours power would be expected to be unavailable and (2) the number of hours for maintenance activities.

The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions. Alternative estimates can be made on a case-by-case basis where justified by the source owner or permitting authority (for example, if historical data on local power outages indicate that a larger or smaller number would be appropriate). Using the 500 hour default assumption, EPA has performed a number of calculations for some typically-sized emergency generators. These calculations indicate that these generators, in and of themselves, rarely emit at major source levels. (Of course, there may be unusual circumstances where these calculations would not be representative, for example where many generators are present that could operate simultaneously).

<u>Cautions</u>

Today's guidance is only meant to address emergency generators as described. Specifically, the guidance does not address: (1) peaking units at electric utilities; (2) generators at industrial facilities that typically operate at low rates, but are not confined to emergency purposes; and (3) any standby generator that is used during time periods when power is available from the utility. This guidance is also not intended to discourage permitting authorities from establishing operational limitations in construction permits when such limitations are deemed appropriate or necessary. Additionally, this memorandum is not intended to be used as the basis to rescind any such restrictions already in place.

Distribution/Further Information

The Regional Offices should send this memorandum to States within their jurisdiction. Questions concerning specific issues and cases should be directed to the appropriate Regional Office. Regional Office staff may contact Tim Smith of the Integrated Implementation Group at 919-541-4718. The document is also available on the technology transfer network (TTN) bulletin board, under "Clean Air Act" - "Title V" - "Policy Guidance Memos". (Readers unfamiliar with this bulletin board may obtain access by calling the TTN help line at 919-541-5384).

cc: Air Branch Chief, Region I-X
Regional Air Counsels, Region I-X
Adan Schwartz (2344)
Tim Smith (MD-12)

Attachment B:
TAR to AQ0307CP01

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM
Juneau, Alaska

Final

TECHNICAL ANALYSIS REPORT
For Air Quality Control Construction Permit
No. 307CP01

United States Air Force
Eareckson Air Station

September 29, 2003

Prepared by Zeena Siddeek
Supervisor Jim Baumgartner

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1. INTRODUCTION

The Eareckson Air Station (EAS) is operated under the control of the United States Air Force (USAF). The 611th Air Support Group under the command of Pacific Air Forces (PACAF) is the permit applicant. EAS occupies the Shemya Island located at the westernmost point in the Aleutian Island chain in the middle of the northern Pacific Ocean. EAS maintains a 10,000 foot long air field and supports activities that include the U.S. Army Space and Missile Defense Command (USASMDC), U.S. Army Corps of Engineers, U.S Navy, U.S. Coast Guard (Kodiak), AT &T Alascom, Federal Aviation Administration (FAA), National Oceanic and Atmospheric Administration (NOAA), U.S. Fish and Wildlife Service, and the Base Operations and Support (BOS) Contractor, Chugach Eareckson Support Services.

The Department has classified the air quality surrounding the EAS as in attainment or unclassifiable with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. Areas in attainment with the NAAQS are also categorized as Class I, Class II, or Class III for the purpose of air quality maintenance. These categories depend on the expected level of industrial growth and the need to protect the air quality of the area. The U.S. Environmental Protection Agency has established ambient air quality increments for each class, with Class I areas being most restrictive. Federal Prevention of Significant Deterioration (PSD) and Alaska Air Quality Regulations designate the region surrounding the Eareckson Air Station as Class II. There are no Class I areas located within 1,000 miles of the stationary source. Because the EAS is greater than 10 kilometers away from a Class I area, the secondary definition of a significant emission increase does not apply as set out in 18 AAC 50.300(h)(3)(xviii).

The EAS is classified as a major source under the Prevention of Significant Deterioration (PSD) regulations on August 7, 1980 described in 18 AAC 50.3000(c)(1), for having the potential to emit greater than 250 tons per year (TPY) of a regulated pollutant. EAS became a PSD major source when the power plant (Building 3049) was constructed in 1975, prior to the PSD program revisions of August 7, 1980. EAS has PTE greater than 250 TPY of nitrogen oxides (NOx), carbon monoxide (CO) and sulfur dioxide (SO_2). Subsequent modifications to the EAS should subject the stationary source to major source review if actual emission increases exceed the thresholds listed in 18 AAC 50.300(h)(3).

EAS has implemented modifications in the past without pre-construction review and permitting under federal New Source Review provisions of the Clean Air Act. USAF did not undergo pre-construction review or evaluate Best Available Control Technology (BACT) for the equipment associated with these projects. In the current permit application, USAF is proposing to mitigate past actions and requesting authorizations for proposed future projects. Thus, the evaluation for modifications at EAS is reviewed in two parts: 1) modifications that have already been implemented and 2) proposed modifications from 2003 through 2007.

<u>Changes at EAS since 1980, are grouped in to the following projects:</u>

<u>Project 1</u>: Between 1980 and 1988 USAF added, upgraded and removed several backup generators and boilers, added a rock crusher, added and replaced aircraft barrier engines and replaced a barrier engine. Specific capacities and ratings of these units and the year in which

the changes took place are listed in Exhibit A, Table A2 of this report. With owner requests to limit emissions and operations, the increase in emissions from this project was less than the applicability threshold levels listed in 18 AAC 50.300(h)(3) for any regulated criteria pollutants.

Project 2: In 1988, USAF installed two 3,000 kW main generators, removed three 1,300 kW and five 1,250 kW generators and installed two firewater pumps of capacities 186 hp and 230 hp. The increased potential emissions from this project were greater than the applicability threshold levels of 40 TPY and 100 TPY for NO_X and CO, respectively.

Project 3: Since 1988 and prior to the 1995 fuel switch, USAF overhauled two primary generators, added, upgraded, removed and replaced backup generators and boilers, added and removed an incinerator, and modified a boiler to burn reclaimed oil. Specific capacities and ratings of these units and the year during which the changes took place are listed in Exhibit A, Table A2. The increased potential emissions from this project was less than the PSD applicability threshold levels listed in 18 AAC 50.300(h)(3) for any regulated criteria pollutants.

Project 4: Changes since 1995 to current. In 1995, a stationary source wide fuel switch from DF-2 (low sulfur fuel No. 2 diesel with 0.15% S) to JP-8 (0.3% S) occurred. The increased potential emissions from the fuel switch were not greater than 40-tpy applicability threshold for SO_2.

Project 5: USAF is proposing to add new equipment and replace existing equipment during the period 2003-2007. The proposed modification will result in an actual increase beyond the applicability threshold level listed in 18 AAC 50.300(h)(3)(B) for NOx, and SO_2.

1.1 Permit History

EAS was issued its first Air Quality Permit to Operate No. 8321-AA009 in September 1983. On September 21, 1994, EAS was issued Air Quality Control Permit No. 9325-AA007 for changes that occurred in 1988. The latter permit was issued with operational restrictions intended to make the 1988 changes a minor modification. This 1994 permit should have undergone pre-construction review under the PSD program. Since this application contains a PSD evaluation of the changes in 1988, the need for the operating limits is negated and therefore, the Department is withdrawing the 1994 permit restrictions for the 1988 change

1.2 Department Findings

USAF submitted an original construction permit application on January 27, 2003 and supplemental information on March 17, 2003 and June 11, 2003. The construction permit application was deemed complete on June 11, 2003.

From review of the permit application, the Department finds that:

1. The EAS is an existing stationary source classified as a PSD major stationary source for NOx and CO emissions under the Department's Air Quality control Regulations as listed in 18 AAC 50.300(c)(1).

2. USAF has submitted a construction permit application to reconcile past PSD permitting issues and get Department authorization to operate the existing emission units and proposed emission units.

3. The industrial processes and fuel burning equipment are subject to the State Air Quality Control Regulations 18 AAC 50.055(a)(1) for visible emissions, 18 AAC 50.055(b)(1) for particulate matter, and 18 AAC 50.055(c) for sulfur compound emissions.

4. The Cooper Bessemer primary generators Nos. 5 and 6 in building 3049 and the two firewater pumps added in 1988 are subject to major source review for NOx, and CO for having emissions increases greater than the PSD thresholds listed in 18 AAC 50.300(h)(3)(B)(ii) and (i). The Department proposes SCR/Oxidation catalysis as BACT for the Cooper Bessemer engines for NOx and CO control and no controls for the firewater pumps.

5. All emission units proposed to be installed between 2003-2007 are subject to major source review for NOx and SO_2 for having emissions greater than the PSD thresholds listed in 18 AAC 50.300(h)(3)(B)(ii) and (iii). The Department proposes no controls as BACT for emission units proposed to be installed between 2003-2007.

6. To protect SO_2 ambient standards and increments, USAF proposes to burn JP-8 fuel oil with a maximum sulfur content of 0.3% by weight.

7. USAF has shown that EAS, as permitted, will not cause or contribute to violations of the ambient NO_2, SO_2, PM-10 and CO air quality standards and PSD increments (as applicable).

8. EAS will have permitted emissions of 1,286 tons per year (TPY) of oxides of nitrogen (NOx), 415 TPY carbon monoxide (CO), 45 TPY particulate matter less than 10 micrometers, 115 TPY of volatile organic compounds and 450 TPY of sulfur dioxide (SO_2)

9. EAS is located within the federal coastal zone. Therefore, project consistency under the Alaska Coastal Management Program (ACMP) is required. The DGC will conduct project consistency review for the federal project.

The application and supplements satisfy the requirements set out in 18 AAC 50.310. Thus, the Department is granting USAF's request and issuing Air Quality Control Construction Permit No. 307CP01 for the Eareckson Air Station.

2. CLASSIFICATION

The EAS is classified under:
1) 18 AAC 50.300(c)(1) – as a PSD major stationary source;

2) 18 AAC 50.300(h)(2) – as a modification that requires a demonstration to show compliance with the applicable air quality standards and increments;
3) 18 AAC 50.300(h)(3) – as a modification that significantly increases the actual emissions of a regulated air contaminant; and
4) 18 AAC 50.305 (a)(3) – as an owner request to revise terms and conditions of a prior construction permit or Air Quality Control Permit issued before 1997.

2.1 Prevention of Significant Deterioration Program

The Federal Clean Air Act established the PSD program to manage air quality by evaluating the emission controls and potential ambient air quality impacts from proposed new or modified major stationary sources. The U.S. Environmental Protection Agency (EPA) has approved Alaska's PSD pre-construction review program for new or modified stationary sources to the State of Alaska. The Alaska Air Quality Control Regulations, 18 AAC 50, contain the PSD pre-construction review program. Entities desiring to build or modify a stationary source subject to the PSD pre-construction review program must submit an application to the Department prior to constructing the stationary source or modification. The Department then reviews the emissions, proposed controls, and predicted ambient impacts, to determine whether the proposed stationary source/modification complies with the air quality standards and program requirements.

The stationary source is a "major" source as classified in 18 AAC 50.300(c)(1). The application describes a proposed modification classified as PSD-significant in 18 AAC 50.300(h)(3). Therefore, the Department requires this project to undergo pre-construction review under the PSD program and obtain an Air Quality Control Construction Permit. This review includes:

- evaluating the potential to emit (PTE) from each modification;
- determining the State and federal emission standards applicable to the project's emitting sources and the project's compliance with emission standards;
- evaluating Best Available Control Technology (BACT) for new or modified emission units and establishing emission or operating limits, which represent BACT;
- determining the attainment status of the air shed;
- reviewing air pollution monitoring data regarding existing air quality and meteorological data in the vicinity of the project;
- identifying the ambient air quality boundary for the stationary source;
- assessing ambient air quality impacts of the project and associated activities relative to National and State Ambient Air Quality Standards (AAQS) and PSD increments; and
- evaluating impacts of the project and associated activities on air quality-related values such as visibility, deposition effects on lands and waters, and effects on vegetation.

2.2 PSD Application Requirements

PSD applicability for the EAS was determined on a project and on a pollutant basis by comparing the potential emission rate of the installed emission units minus the actual emission rate of the removed emission units to the PSD threshold listed in 18 AAC 50.300(h)(3)(B). The Department used the emission unit's potential emissions as its actual emissions amount in accordance with 18 AAC 50.910(a).

For a modification that consists of a discrete installation of a new unit and removal of an old unit, the applicant may simplify the examination by considering the new unit's projected actual emission increase and old unit's actual emission decrease in lieu of performing a stationary source-wide PSD applicability determination. This approach may also reduce the scope of the PSD review. Based on our review of permit application, we understand that EAS has made one discrete PSD significant modification since 1980 and proposes a PSD significant modification between 2003 and 2007 (post-2002). Therefore, the Department has conducted PSD reviews for the 1988 power plant modification project and post-2002 project. The Department's reviews are described in this technical analysis report.

Exhibit A, Table A2 shows this comparison for each pollutant and indicates whether a PSD review is required.

2.3 PSD Review Trigger Events

2.3.1 1988 Power Plant Addition

The first PSD significant emission trigger event occurred in 1988 with modifications to the main power plant as follows:
- install the Cooper-Bessemer primary diesel generators No. 5 and 6;
- install the two Detroit emergency firewater pumps (Building 3057); and
- remove eight (8) existing generating units (Building 3051).

The emission increases resulting from the unrestricted operation of the primary generator Units 5 and 6 exceeded PSD thresholds for NOx, and CO. Therefore the project in 1988 should have undergone PSD review. As such, the modifications resulting from the power plant addition are being reviewed under PSD regulations in the current permit action. EAS made several changes prior to 1988 project, but is requesting operational limits to the emergency backup generators, firewater pump, and aircraft barrier engines of up to 1,000 hours per year so the resulting potential emissions from previous changes would not exceed PSD significant levels.

2.3.2 Proposed Modification for years 2003-2007

USAF is proposing the following changes to the EAS during the 2003-2007 period:
- install two emergency firewater pumps of 1,100 hp each;
- install two firewater pumps of 160 hp each hp;
- modify a 2.79 MMBtu/hr boiler to fire reclaimed oil;

- install two 600 kW emergency generators;
- replace four 2,100 hp firewater pumps with 1,100 hp firewater pumps;
- replace four 65.9 hp aircraft barrier engines;
- install a solid waste incinerator;
- install two 2.01 MMBtu/hr boilers;
- replace a 2.05 MMBtu/hr and 2.6 MMBtu/hr boilers with two 2.65 MMBtu/hr boilers;

The cumulative emissions from the proposed project will be greater than the PSD threshold for NO_X and SO_2.

2.3.3 Baseline Emissions

The baseline date for SO_2 and PM-10 fall within one year of August 7, 1980, the date from subsequent modifications are compared with PSD applicability thresholds. As such, actual emissions on August 7, 1980 were used as baseline emissions for SO_2 and PM-10. Actual emissions on August 7, 1980 were determined using appropriate AP-42 emission factors. Detailed calculations of baseline emissions for each equipment can be found in on the CD ROM provided with the permit application. A listing of emission unit installation and modifications that occurred since 1980 and associated emissions are shown in Exhibit A, Table A2.

2.3.4 Emission Changes since Baseline

Table 2.1 presents cumulative emissions since 1980 that resulted from historical modifications to the stationary source. Emissions were determined using AP-42 emission factors. The Department concurs with USAF's method of calculation. Pollutant emission changes since the 1980 baseline date and basis of calculation are listed in Exhibit A, Table A2. Emissions from existing and proposed emission units that are subject to this permit review are shown in Exhibit A, Table A1.

Table 2.1: Cumulative Emissions resulting from modification

Project	Modification	Emissions in tons per year				
		PM-10	SO_2	NOx	CO	VOC
Project 1	Changes from 1980 to 1988 before power plant additions of 1988	2.2	23.8	39.6	34.1	2.4
Project 2	1988 power plant additions	-1.0	6.3	696.1	151.1	22.1
	Cumulative changes up to 1988	1.2	30.1	735.7	185.2	24.5
Project 3	Changes since 1988 and prior to caretaker status/fuel switch of September 1995	2.6	37.5	44.1	10.8	2.1
	Cumulative changes up to 1995	3.8	67.6	44.1	10.8	26.6
Project 4	Changes since 1995 including changes from caretaker status/ fuel switch to 2002	-0.6	38.8	-36.6	12.5	5.8
	Cumulative changes	3.2	106.4	7.5	23.3	32.4
Project 5	Proposed changes for 2003 and beyond	1.3	16.4	55.3	41.0	2.7
	Cumulative changes since post 2002	4.5	122.8	62.8	64.3	35.1

[a] Emission changes resulting from fuel switch is shown in Table B-1 of Addendum 2 of the permit application.

In 1995 the stationary source underwent a base wide fuel switch from DF-2 (low sulfur No. 2 diesel) to JP-8. The maximum sulfur content for JP-8 and DF-2 fuel were assumed to be 0.3% and 0.15%, respectively. The SO_2 emissions resulting from fuel switch with higher sulfur content did not exceed the PSD threshold. As shown in Table 2.1 the cumulative changes up to 1988 are greater than the PSD thresholds for NOx and CO. Similarly, the combined cumulative changes since 1988 and proposed changes beyond 2003 triggers PSD review for SO_2, and NOx.

3. EMISSION STANDARDS

For each stationary source or modification subject to construction permitting, the applicant must show that the proposed units comply with State and federal emission standards. The Department has adopted federal New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs), by reference in 18 AAC 50.040. In addition, the Department has unit-specific emission standards listed in 18 AAC 50.050-090.

3.1 New Source Performance Standards

The U.S. Environmental Protection Agency promulgates and implements New Source Performance Standards (NSPS). The intent of NSPS is to provide technology-based emission control standards. EPA may delegate to each state the authority to implement and enforce standards of performance for new stationary sources located in that state. The Department has incorporated by reference the NSPS effective July 1, 1997, for specific industrial activities, as listed in 18 AAC 50.040. However, EPA has not delegated to the Department the authority to administer the NSPS program at this time.

EAS has fuel storage tanks subject to NSPS Subpart K and Kb and a municipal solid waste landfill subject to subpart WWW. However these equipment were installed prior to 1980 and are not part of the described projects subject to this permit decision. The fuel storage tanks subject to NSPS Subpart K and Kb for volatile organic liquid storage vessels and municipal solid waste landfill subject to NSPS Subpart WWW will be dealt with in the Operating Permit that will in include terms and conditions for all the equipment in the stationary source.

3.2 National Emission Standards for Hazardous Air Pollutants

The U.S. Environmental Protection Agency (EPA) promulgates National Emission Standards for Hazardous Air Pollutants (NESHAPs). 18 AAC 50.040 adopts the federal hazardous air pollutant regulations, 40 CFR 61, and 40 CFR 63, by reference. EPA may delegate to each state the authority to implement and enforce certain standards for units located in that state. At this time, EPA has not delegated authority to the Department to administer the NESHAPs program. USAF is not proposing any new or modified units subject to Federal NESHAPs.

3.3 Alaska Emission Standards

Industrial processes and fuel-burning equipment at the stationary source are subject to specific visible emission, particulate matter, and sulfur compound emission standards as listed in

18 AAC 50.055, open burning prohibitions as listed in 18 AAC 50.065, and fugitive dust prohibitions listed in 18 AAC 50.045(d). The Department has reviewed file documents and prepared monitoring, record keeping, and reporting requirements within the construction permit for compliance with the standards.

3.3.1 Visible Emissions

The industrial processes and fuel burning equipment and incinerators are subject to a 20 percent visible emission standard as listed in 18 AAC 50.055(a)(1) and set out in Section 7, Conditions 12 and 16.

USAF did not provide a compliance demonstration for the standards. Because oil-fired units have the potential to exceed the opacity standard, the Department is requiring USAF to verify compliance by performing Visible Emission Surveillance tests for each unit that are not insignificant units based on 18 AAC 50.335(r) every 12-month period as stated in Permit Condition 12.3. For insignificant units USAF is required to provide an annual certification to comply with standards. USAF must also conduct Visible Emission Surveillance tests upon the Department's request and report in accordance with Permit Conditions 44-46.

3.3.2 Particulate Matter

All fuel burning equipment at the EAS are subject to a particulate matter standard of 0.05 grains per dry standard cubic foot of exhaust gas (gr/dscf), as listed in 18 AAC 50.055(b)(1), and set out in Section 7, Condition13 of the permit. EAS demonstrated compliance with state emission standards for grain loading for the units installed in 1988 and emission units proposed for the post 2002 project. EAS is required to demonstrate compliance for all emission units subject to the current permit action and not limited to the emission units installed in 1988 and emission units proposed for the post 2002 project. Further, the Department was unable to concur with the methodology used in the demonstration.

Therefore the Department independently examined compliance with the grain loading emission standards using the equation 19-1 from 40 CFR 60, Appendix A:

$$E = CF(20.9/(20.9-O_2)) \quad \text{where}$$

E = Emission Factor, lb/MMBtu
F = F factor specific to fuel type (9,190 dscf/MMBtu for diesel fuel or DF-8)
O_2 = % oxygen in exhaust gas typical to equipment
C = Pollutant Concentration lb/dscf

EAS has not selected the firewater pumps and emergency backup engines proposed to be installed for the post 2002 project. EAS does not have emission unit specific emission factors for PM available for the post 2002 emission units or existing units.

Table 3.3-1 shows particulate matter concentrations estimates using AP-42 emission factors for emission units burning DF-8 fuel. Oxygen contents used below are typical values for each category of units or most conservative estimates.

Table 3.3-1: Particulate Emission Estimate

Building	Description	Capacity	Emission Factor	Oxygen Content	Reference	Concentration gr/dscf
3049	Cooper Bessemer	3,000 kW	0.1 lb/MMBtu	8%	AP-42 Table 3.4-1	0.047
3057	Two Firewater Pumps #1 & #2	186 hp and 230 hp	0.31 lb/MMBtu	12%	AP-42 Table 3.3-1	0.101
76-522-ILS	Two EB Generators #1& #2	600 kW	0.1 lb/MMBtu	12%	AP-42 Table 3.4-1	0.031
3049	Two Firewater Pumps #1 & #2	160 hp	0.31 lb/MMBtu	12%	AP-42 Table 3.3-1	0.101
755	Reclaimed oil fired Boiler	2.66 MMBtu/hr	$51A^b$ lb/10^3 gal	3%	AP-42 Table 1.11-1	0.100
754	Two Boilers	2.65 MMBtu/hr	2 lb/10^3 gal	0%	AP-42 Table 1.3-1	0.012
76-522 and 76-524 ILS	Two EB Generators	600 kW	0.1 lb/MMBtu	12%	AP-42 Table 3.3-1	0.031
84-110	Two Firewater Pumps #1 & #2	1,100 hp	0.1 lb/MMBtu	12%	AP-42 Table 3.3-1	0.031
523	Four Firewater Pumps #1-4	1,100 hp	0.1 lb/MMBtu	12%	AP-42 Table 3.3-1	0.031
74-041-1	Aircraft Barrier Engines #1-4	65.9 hp	0.31 lb/MMBtu	12%	AP-42 Table 3.3-1	0.101

[b] A is the ash content of used oil assumed determined to be 0.36% from fuel analysis

As shown in Table 3.3.1, small oil fired diesel engines less than 600 hp, will not comply with state grain loading requirements when using AP-42 emission factors. Therefore, in order to ensure compliance with the standard, the Department added a requirement for USAF to provide vendor guarantees or conduct PM source tests of representative units as set out in condition 14 and report in accordance with permit condition 47.

USAF did not demonstrate compliance with grain loading emission standard for the reclaimed oil-fired boilers burning used oil. The Department carried out an independent analysis using AP-42 emission factor using Method 19-1 and fuel factor of 9,190 dscf/MMBtu, a heating value of 150,000 Btu/gal for used oil and 3% excess oxygen.

As shown in Table 3.1.1, the reclaimed oil fired boiler will not meet state grain loading requirement. Therefore, USAF is required to blend the used oil with diesel fuel oil in the ratio of used oil to diesel oil of 1:2 parts as set out in Condition 14.3, to meet compliance with grain loading requirements. Details of the particulate matter concentrations and the blending ratio calculations are provided in Exhibit B of this report.

3.3.3 Sulfur Compounds

All fuel burning equipment are subject to the sulfur compound emission standard as set out in 18 AAC 50.055(c). Sulfur compound emissions from fuel burning equipment, expressed as sulfur dioxide, may not exceed 500 ppm averaged over a period of three hours as set out in Permit Section 7, Condition 15.

All equipment subject to the current permit action will burn DF-8, motor vehicle unleaded gasoline (MUR) and used oil as listed in Table 1, Emission Unit Inventory of the permit, with a maximum sulfur content of 0.3% by weight. Typically, fuel-burning equipment is operated with combustion air in excess of stoichiometric conditions to ensure fuel is completely burned under non-ideal conditions. This excess air dilutes exhaust gas concentrations of sulfur compounds. Accounting for excess air normal to a fuel-burning unit, the units should comply with the sulfur compound limit while burning fuel with a sulfur content somewhat greater than 0.74 percent by weight.

The Department proposes, periodic monitoring, record keeping, and reporting requirements for fuel oil to ensure compliance with the sulfur compound standard in Condition 15 of the permit.

3.3.4 Ice Fog Standards

The Department will, in its discretion, require a person who proposes to build or operate an industrial process, fuel-burning equipment, or incinerator in an area of potential ice fog to obtain a permit and to reduce water emissions. Ice fog is not a concern at the EAS and the Department is not placing any additional conditions in the permit.

3.3.5 General Air Pollution Prohibited

18 AAC 50.110 and Permit Condition 20 state that no person may permit any emission that is injurious to human health or welfare, animal or plant life, or property, or that would unreasonably interfere with the enjoyment of life and property. The Department has proposed in Permit No.307CP01, Conditions 21.1 and 21.2 that USAF record all public complaints and take reasonable actions to correct air pollution complaints resulting from emissions at EAS. The Department has also proposed in Condition 11 that USAF provide advanced notice of any modifications at EAS which would result in an increase in allowable emissions from the stationary source.

4. BEST AVAILABLE CONTROL TECHNOLOGY

The Department's goal for the Best Available Control Technology (BACT) review is to evaluate available technologies, identify BACT for the project's emission units, and establish emission or operational limits which represent BACT. This review is conducted in accordance with State and federal rules and guidelines. In this section, the Department evaluates the available control technologies for each emission unit and selects BACT. In addition, the Department assesses the level of monitoring, record keeping, and reporting necessary to ensure the applicant applies BACT.

Under the State of Alaska's PSD Provisions of the Air Quality Control Regulations, an applicant subject to pre-construction review must show that BACT will be installed and used for each new or modified unit. BACT is defined as an emission limit that represents the maximum reduction achievable for each regulated air contaminant subject to pre-construction review under the PSD provisions of the Clean Air Act.

The 1988 PSD triggering event listed in Table 2.1 requires that the Cooper-Bessemer primary generator units 5 and 6 will be subject to retroactive BACT analysis. For this project, BACT evaluation is required for NO_X and CO.

For the post 2002 PSD trigger event listed in Table 2.1, the small capacity heaters and emergency backup power generation equipment will be subject to a BACT analysis.
For this project, BACT evaluation is required for NO_X and SO_2.

All BACT requirements, with limits, monitoring, record keeping, and reporting obligations are incorporated in Section 8 of the permit. Table 4.0-1 below summarizes the BACT limits proposed by the Department.

Table 4.0-1: Department proposed BACT Limits

Emission Unit	NO_X Limits		CO Limits		SO_2 Limits	
	BACT limit	Basis	BACT limit	Basis	BACT limit	Basis
Cooper Bessemer Primary Generators #5 and #6	9.7 lb/hr	SCR[(a)]/Oxidation Catalysts	4.4 lb/hr	SCR[(a)]/Oxidation Catalysts	N/A[(d)]	N/A[(d)]
186 hp firewater pump	N/A[(c,d)]	GCP[(b)]	N/A[(c,d)]	GCP[(b)]	N/A[(d)]	N/A[(d)]
230 hp firewater pump	N/A[(c,d)]	GCP[(b)]	N/A[(c,d)]	GCP[(b)]	N/A[(d)]	N/A[(d)]
Post 2002 equipment changes	N/A[(c,d)]	GCP[(b)]	N/A[(c,d)]	N/A[(c)]	N/A[(d)]	0.3% S limit

a. SCR = Selective Catalytic Reduction
b. GCP = Good Combustion Practice
c. N/A = Not Applicable
d. The Department did not impose an emission rate representative of BACT due to the size of the unit and operational limit

4.1 Standard for Making BACT Determinations

The methodology USAF used to identify BACT is the five-step "top-down" methodology set forth in the U.S. EPA's proposed *New Source Review Rule Revisions* (EPA 1990). EPA has published numerous policy memorandums and guidance documents to assist applicants and permitting authorities in using the top-down approach. Although the Department is not legally bound to follow the top-down methodology, the Department may choose to use the methodology at its discretion, and has chosen to use it for this permit.

The following is a description of the top-down process taken from EPA publications.

In step 1, the applicant identifies all available control options for the emission unit and the pollutant under consideration. This includes technologies used throughout the world. To assist in identifying available controls, USAF reviewed the available controls listed on EPA's RACT/BACT/LAER Clearinghouse (RBLC) bulletin board where permitting agencies nationwide have listed the BACT control technologies imposed for PSD actions within the past five years. The RBLC is not a comprehensive list of all BACT control technologies since it does not include stationary sources that do not undergo PSD actions but have BACT imposed to avoid PSD review. In addition, not all agencies submit their updates for this bulletin board.

In step 2, the applicant evaluates the technical feasibility of the various control options in relation to the specific emission unit under consideration. If the applicant can clearly document and demonstrate, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option, it is eliminated from further consideration in this step.

In step 3, the remaining control options are listed in order of control effectiveness for the pollutant under review, with the most effective option at the top. In this step, the applicant also presents detailed information about the control efficiency, the expected emission rate, the expected emission reduction, and the cost, environmental, and energy impacts for each control option. An applicant proposing to use the most effective option is not required to provide the detailed information for the less effective options.

In step 4, the energy, environmental, and economic impacts are considered to arrive at the final level of control. The applicant is responsible for presenting an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts.

EPA's guidance describes the process for this step as follows:

> If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts on other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then, the next most stringent in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any emission unit-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

The process concludes in step 5, where the most effective control option not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review.

In 1980, the EAS had the potential to emit greater than 250 tons per year of a regulated pollutant, and was therefore classified as a PSD Major stationary source under 18 AAC 50.300(c)(1). According to 18 AAC 50.300(h)(3), any modification to a PSD major stationary source after August 7, 1980 that results in an increase of actual emissions greater than PSD applicability thresholds is subject to a BACT review for that pollutant.

USAF has made numerous changes to the EAS involving installations and removals of fuel burning equipment. The installation of the fifth and sixth Cooper Bessemer primary generators and the installation of two firewater pump engines resulted in emissions greater than the PSD applicability threshold for NO_X and CO. The proposed changes for 2003 and beyond will result in emissions greater than PSD applicability threshold for NOx and SO_2.

4.2 BACT Determination for NO_X

USAF evaluated several NO_X control methods as BACT for the emission units installed in 1988 and for the emission units proposed to be installed for the post-2002 project. The emission units under review are two 3,000 kW Cooper Bessemer Diesel Electric Generators, two Detroit firewater pump engines of 186 hp and 230 hp and each of the proposed 8 firewater pump engines, four emergency generators, four aircraft barrier engine and 6 boilers. The specific options and an evaluation of results are summarized below, and discussed in detail in this section.

In this construction permit application, the two Cooper Bessemer primary generators and two firewater pump engines installed in 1988 will undergo an after-the-fact BACT assessment. The proposed firewater pump engines, emergency generators, boilers and solid waste incinerator for the post-2002 project will undergo BACT assessment.

Table 4.2-1: Summary of NO_X BACT for Diesel Engines

Applicable Controls	Emission Units	Technically Feasible	Economically Feasible	BACT
Selective Catalytic Reduction (SCR)	Cooper Bessemer Generators	Yes	Yes	Yes
	Firewater pumps and Post 2002 units	No	N/A	N/A
Selective Non-Catalytic Reduction (SNCR) (NOxTECH system)	Cooper Bessemer Generators	Yes	No	No
	Firewater pumps and Post 2002 units	No	N/A	N/A
Non-Selective Catalytic Reduction (NSCR)	All	No	N/A	N/A
SCONOx™ System	All	No	N/A	N/A
XONON	All	No	N/A	N/A
Fuel Injection Timing Retard (FITR)	Cooper Bessemer Generators	Yes	No	No
	Firewater pumps and Post 2002 units	No	N/A	N/A
Electronic Fuel Ignition	All	No	N/A	N/A
Separate Cooling Water to the Aftercooler (Turbocharger/Aftercooler)	Cooper Bessemer Generators	Yes	No	No
	Firewater pumps and Post 2002 units	No	N/A	No
Improved Injector Design and low NO_X Desigi	All	No	N/A	N/A
De-rating	All	No	N/A	N/A
Low-NO_X Design	All	No	N/A	N/A
Water Injection	All	No	N/A	N/A
Humidity Control	All	No	N/A	N/A
Flue Gas Recirculation (FGR)	All	No	N/A	N/A
Direct Water Injection	All	No	N/A	N/A
Fuel Additives or Alternative Fuels	All	No	N/A	N/A
Propane Fumigation	All	No	N/A	N/A
Good Combustion (GCP)	Cooper Bessemer Generators	Yes	Yes	No
	Firewater pumps and Post 2002 units	Yes	Yes	Yes

4.2.1 NO_X BACT Analysis for the Cooper Bessemer Diesel Electric Generators

The following presents the Department's BACT review using the step-by-step top-down approach described previously for the Cooper Bessemer Diesel Electric Generators.

Step 1 – Identify All Control Technologies

USAF identified eighteen control technologies for control of NO_X that are applicable to these emission units. See Table 4.2-1.

In general, the Department concurs with USAF's identification of applicable control technologies.

Step 2 – Eliminate the Technically Infeasible Options

USAF eliminated from consideration the following technically infeasible options for the Cooper Bessemer Diesel Engines:

- Non-Selective Catalytic Reduction (NSCR) because of the inability to control the necessary air to fuel ratio for varying loads in IC engines;
- SCONOx™ because no units smaller than 3MW size range have been operated and permitted;

- XONON because the technology is being developed for large gas turbine engines but has not been developed for diesel IC engines;
- Electronic Fuel Injection because the technology is available for some of the new large stationary diesel engines but extended Research and Development (R&D) and time is necessary before it can be applied to the old Cooper Bessemer engines.
- Improved Injector Design and Low-NO_X Design because the old Cooper Bessemer engines would need to be retrofitted with improved injector design or low-NO_X injectors involving extensive engineering costs;
- Water Injection because of the significant amounts of maintenance and repair on a retrofitted IC engine and the non availability of large quantities of purified water;
- Humidity Control because the technology has limited application and is inefficient.
- Flue Gas Recirculation because the technology is currently limited to spark ignition gas engines and some industrial boilers and because of inefficiency of the control;
- Alternative Fuels because of its remote location, there is no infrastructure at EAS to accommodate an alternate fuel;
- Propane Fumigation because the technology has not been adequately tested and is not commercially available for IC engines;

Fuel Injection Timing Retard is a technology that delays the injection of fuel to a time when the compression chamber is expanding. The larger volume produces a lower peak flame temperature, thus reducing thermal NO_X formation. FITR however, reduces fuel efficiency resulting in increases in CO and SO_2 emissions through increased fuel consumption. NO_X emission reduction is in the order of 10-30% depending on the degree of FITR. Excessive injection delays on the other hand can cause engine misfire.

Fuel Injection Timing Retard is deemed technically infeasible. Cooper Energy Services informed USAF that fuel injection timing retard was not recommended for these engines as it was known to increase fuel consumption, make the engine run abnormally hot, and increase emissions of particulate matter and carbon monoxide. The deleterious effects of retarding the injection timing were contrary to good operating practices and have also been shown to shorten engine operating life and contribute to more frequent than normal engine overhauls due to misfiring and rough running. According to Cooper Energy Services, unless the engines could be switched to a different type of fuel, such as natural gas, no other potential combustion modifications were available for these engines. Therefore, this technology is eliminated from further consideration.

Cooper Energy Service's (Cooper) concurs with USAF the BACT options that were determined infeasible for the Cooper Bessemer Engines. Low-NO_X injectors would take major research and development effort. Water injection is in a research and development phase that has not been applied in a commercial environment. The turbocharger/aftercooler is usually needed to reach the required horsepower output without making the engine displacement larger. The specific LSVB model was never available without the turbocharger/aftercooler design. Cooper has test results that show exhaust temperature increases and fuel economy decreases as the degree of timing retard increases.

Direct Water Injection (DWI) is an alternative to SCR for marine applications. Its application to land-based base load power generation is largely experimental in the US. Its use at EAS would require an extensive R&D for retrofitted application on an existing mechanically timed engine without adequate electronic controls or materials, designed for DWI use.

Other primary emission control technologies include segregated cooling systems, intake air humidification, and other pre-combustion chamber control techniques that serve to limit combustion temperature and the heat transfer to the engine cylinder and piston surfaces. These technologies have been applied on new electronically controlled engines but to renovate or re-engineer a 30-year old engine to utilize these technologies for emission control is unknown. Although "state of the art" electronic air controlled diesel injection technology is currently available, the cost and availability of this technology for an existing mechanically timed engine design like the Cooper Bessemer would be prohibitive.

The Department reviewed and concurred with these findings.

Step 3 – Rank the Remaining Control Technologies by Control Effectiveness

A ranking of the three remaining control technologies for the Cooper Bessemer engines by control effectiveness, expressed as percent reduction in NO_X from the base case and emission in tons per year after application of the control option, is shown below. The base case is the configuration of the engine as installed in 1988.

Table 4.2-2: NO_X Control Effectiveness for the two Cooper Bessemer Engines

Rank No.	Control Option	Uncontrolled actual emissions (tpy)	Total NO_X removed	Emission Rate (tpy)	Percent Reduction (%)	Cost $/ton removed	
						Applicant Estimate	Dept Revised
1	NOxTECH	845	811	34	96	8,558	3,688
2	SCR/Oxidation catalyst	845	761	84	90	1,307	1,168
3	GCP	845	0	845	0		N/A

USAF provided detailed discussion of the economic, environmental, and energy impacts of each control option in the application and addenda. Tables 4-4 through 4-17, Addendum 1, March 17, 2003 includes cost estimates for the add-on controls listed above.

USAF estimated costs per ton of pollutant removed based on actual emissions and potential emissions projected back to 1988 dollars.

Step 4 – Evaluate the Most Effective Controls and Document Results

NOxTECH (Option 1) is the most effective control applicable to EAS's Cooper Bessemer engines as shown above with a 96% reduction of NO_X. NOxTECH is considered a type of Selective Non-Catalytic Reduction where NO_X reduction is achieved autocatalytically by gas-phase reaction, with no catalyst. NO_X is reduced to nitrogen and water by injecting urea or ammonia at a temperature range of 1,400 to 1,500°F. Additionally the self-sustained reactions deplete hydrocarbons, CO, soot and ammonia slip without generating any hazardous by-products. The process was not available at the time and technically infeasible in 1988. However based on the EPA's injunctive relief policy of 1992, previously unavailable technologies may be considered for BACT analysis.

USAF provided vendor quotes for the installation and operation of the NOxTECH system. USAF provided cost estimates of removing a ton of NO_X based on actual emissions as well as potential emissions. Since the EAS is projected to increase utilization of the existing unit in response to increased activity at the base, the Department will evaluate the cost estimates based on future potential emissions.

The total capital cost of investment is estimated at $13.3 million. The total annualized cost of the capital (based on 5-year economic life of the equipment and miscellaneous indirect costs) and total direct annual cost is in the order of $6.9 million. The Department did not agree with USAF's use of the LAF and SSF factors for the equipment.

Due to the remote location of EAS, USAF corrected the total capital investment costs using two correction factors. The first one is a site specific, location adjustment factor (LAF) of 3.44 for EAS that reflect the average statistical difference in normal labor, material and equipment costs compared to similar facilities built in different geographical locations. The second factor is a site sensitivity adjustment factor (SSF) of 1.119 to account for costs associated with uniqueness of the conditions involved in relation to labor. The SSF was estimated using factors of 0.059, 0.04 and 0.02 for a "substantially below normal" labor force, housing availability and material availability, respectively. In general, the Department concurs with the LAF to be applied for construction and installation of equipment in Shemya. The Department rejects the use of the SSF in view of the installation of the SCR module not being labor intensive.

The Department revised the estimates to apply the LAF only for installation costs. The Department also revised the 5-year life of the equipment to 7 years to adjust the cost estimates. The revised cost estimate for NO_X reduction is in the order of $3,680 per ton of NO_X removed (see Exhibit C for applicant's cost estimate versus the Department's revised estimates).

The collateral impact clause of the BACT definition allows permitting authorities to temper the stringency of BACT in cases where the energy, environmental, or economic impacts that are associated with the use of a control option at a specific stationary source are viewed by the review agency as sufficiently adverse as to render the use of that technology inappropriate for a given stationary source. The applicant did not identify collateral energy or environmental impacts for this technology sufficiently adverse to render the use of NOxTECH as inappropriate as BACT.

The Department has compared the economic cost of NOxTECH with its recent diesel engine BACT decisions as set out in the table below:

Table 4.2.3: Diesel Engine NO_X BACT Costs

Permittee	Stationary source	Date	Cost per Ton
BPX	Badami	9/10/1997	$0[1]
BPX	Northstar	2/5/1999	$0[1]
Nushagak Electric Coop.	Dillingham Power Plant	5/12/2000	$620
Ketchikan Public Utilities	Bailey Street Power Plant	6/4/1998	$1318
Nome Joint Utilities	Snake River Power Plant	12/28/1999	$0-$171
Unisea Seafoods	Unalaska	1/17/1997	$0[1]
USAF	Eielson AFB	12/10/1998	$0
Cominco Alaska	Red Dog Mine	4/26/2001	$0[1]
Kotzebue Electric	Kotzebue Power Plant	6/4/2002	$0-74

Note 1: FITR, electronically controlled fuel injection timing, or low emission configuration was considered as base-case with no associated cost, at these facilities.

Because the NOxTECH system control cost of $3680/ton significantly exceeds that historically required as BACT for NO_X control from diesel generator sets, the Department concludes that this emission control option should be rejected based on economic considerations.

Selective Catalytic Reduction (SCR) (Option 2) is a technology in which ammonia or urea is injected in the presence of a catalyst (usually a noble metal) to react with NO_X to form water and nitrogen in the exhaust flow. A well-designed SCR system can achieve up to 90% NO_X reduction efficiency. The NO_X reduction is however, largely dependent upon optimum temperatures. Ammonia, as a hazardous material may pose worker safety concerns during emergency releases. However, these concerns may be ameliorated by safe worker handling practice with sufficient preventive maintenance, or by substitution of a urea-based SCR system for the installation.

Most SCR systems operate in the 500 to 800°F temperature range. The SCR process requires good control and continual adjustment of the ammonia or urea injection rate to match the rate of NO_X formation. Additionally fuel bound sulfur reacts with ammonia or urea to form ammonium sulfate that fouls the surface of the catalyst, resulting in requiring premature replacement of the catalyst.

Alternatively, the use of vanadium pentoxide (V_2O_5), can be used to reduce fouling. However, V_2O_5 is a hazardous substance that will have to be shipped off site for disposal, or returned to the vendor for recycling. With the option of recycling, the collateral disposal cost and waste generated is offset. The economic cost of this collateral impact can be quantified and assigned an economic cost for determining control costs.

Likewise, there is a nominal energy penalty associated with changes to engine back-pressure due to the add-on controls and energy required to operate the urea mix tank and urea solution injection pump. Although discounted and not quantified by the applicant, the Department recognizes these as additional economic costs of controls. However, based on the applicant's approach, the Department anticipates the added energy cost is inconsequential.

Finally, SCR has an additional environmental risk--potential for ammonia slip in the controlled exhaust from unused reagent. Ammonia slip is controlled by proper engine NO_X mapping during system start-up and reagent injection just sufficient to achieve the desired level of NO_X emission control.

During and after the public comment period USAF provided additional cost information to persuade the Department to remove the requirement for SCR. USAF provided documentation from a vendor for the purchase of SCR units. Additionally, USAF provided documentation of construction cost estimates for a previous power plant renovation and replacement study carried out by HMS Inc. in March 2001 for the EAS. Similar documentation by the Core of Engineers (Tri-Service Automated Cost Engineering System (TRACES)) was submitted to the Department. The HMS cost estimates include cost allowance for labor, material and freight with 30% allowance for contingencies. The TRACES estimates list cost of freight separately. Both HMS and TRACES estimates are based on installation of SCR for the 6 Cooper Bessemer engines for a project that USAF previously considered for the Eareckson power plant.

USAF provided cost estimates using different methods that included estimates from vendor quote, Location Adjustment Factor (LAF) of 3.44, US Army Corp. of Engineers TRACES document and HMS Inc. USAF included the cost of Continuous Emission Monitoring Systems in recognition of the Compliance Assurance Monitoring (CAM) rule applicable with add on controls. USAF included also the cost of water treatment that was overlooked in the previous estimates.

The Department considered that the HMS costs estimate provide the most realistic costs for the installation of SCR. The Department did not completely concur with the applicant's costs and therefore, made adjustments that were deemed necessary to arrive at a more representative cost estimate. Based on the adjusted costs, the capital cost to install SCR on the two Cooper Bessemer engines is in the order of \$1.6 million. The total annualized cost of the capital (based on 7-year economic life of the equipment and miscellaneous indirect costs) and total direct annual cost is in the order of \$888,500. These estimates result in \$1,168 per ton of NO_X removed. (see Exhibit C for applicant's cost estimate versus the Department's revised estimates). This control cost falls within the range of the Department's recent BACT decisions, as shown in Table 4.2-3. The Department's preliminary estimates of \$1,270 per ton of NO_X removed and \$3,700 per ton of CO removed were based on vendor data, application of LAF factors and absent CEMS and water treatment costs (see Exhibit C of preliminary Technical Analysis Report).

Although the Department has in the past rejected SCR as BACT for a diesel engine based on economic and other considerations as applied to different stationary sources, the Department believes that the significantly lower control costs associated with the use of SCR at EAS, as compared to the costs found in recent BACT determinations, do not foreclose SCR as BACT in this specific instance.

Condition 17.1a of the permit requires the Cooper Bessemer primary engines to meet the 9.7 lb/hour and 90% removal efficiency NO_X limit representative of BACT. Condition 17.1b requires the installation of SCR in compliance with 90% NO_X emission reduction. Condition 17.1c requires the installation Continuous Monitoring Emission Systems (CEMS) for NO_X monitoring as dictated by the Compliance Assurance Monitoring (CAM) rule. The results must be reported as indicated in permit Section 8. To assure against excessive ammonia slip, the Department imposed a 15 ppmv ammonia exhaust limit concurrently with periodic NO_X CEMS relative accuracy testing within the preliminary construction permit.

4.2.2 NO_X BACT Analysis for all other emission units

Table 4.2.4. Small Emission Units under review for BACT:

Unit Location	Unit Description	Fuel Type	Operating Limit (hrs/yr)	Installation Date	Rating
3057	Firewater Pump (Detroit #5)	DF-8	1,000	1988	186 hp
3057	Firewater Pump (Detroit #6)	DF-8	1,000	1988	230 hp
84-110	Firewater Pump	DF-8	500	2003	160 hp
84-110	Firewater Pump	DF-8	500	2003	160 hp
523	Firewater Pump Unit #1	DF-8	500	2004	1,100 hp
523	Firewater Pump Unit #1	DF-8	500	2004	1,100 hp
523	Firewater Pump Unit #1	DF-8	500	2004	1,100 hp
523	Firewater Pump Unit #1	DF-8	500	2004	1,100 hp
76-524	EB Generator (ILS Unit #1)	DF-8	500	2003	600 kW
76-524	EB Generator (ILS Unit #1)	DF-8	500	2003	600 kW
74-041-1	Four (4) Aircraft Barrier Engines	MUR	500	2005	65.9 hp
755	Boiler (Unknown)	Reclaimed Oil/DF8		2003	2.79 MMBtu/hr
597	Boiler (Unknown)	DF-8		2005	2.01 MMBtu/hr
597	Boiler (Unknown)	DF-8		2005	2.01 MMBtu/hr
754	Boiler (Unknown)	DF-8		2005	2.65 MMBtu/hr
754	Boiler (Unknown)	DF-8		2005	2.65 MMBtu/hr
619	Solid Waste Incinerator	DF8/Solid waste		2005	750 lb/hr

The following presents the USAF's final BACT review using the step-by-step top-down approach described previously.

Step 1 – Identify All Control Technologies

USAF identified SNCR, FITR , water injection, 3-way catalytic converters and SCR for small diesel engines. For boilers, they identified, Low NO_X burners, FGR, SCR, NOxTECH, water injection, lime reagent injection, Burner NO_X tuning, Reduce Nitrogen bearing fuels, Oxyfuel burners, SNCR and wet scrubbers. In general, the Department concurs with USAF's identification of applicable control technologies.

Step 2 – Eliminate the Technically Infeasible Options

On account of their size, the add-on control technologies available are not feasible for the small capacity heating and diesel engines to be installed in the post 2002 equipment. The use of an owner requested operating limit for the diesel engines has reduced emissions to insignificant levels. Good Combustion Practices (GCP) will be an inherent design feature of the new equipment. USAF asserts that the equipment vendor filling the procurement for the proposed equipment would utilize a state-of-the art fuel oil burner system. Such new equipment specifications are intended to be GCP inherently.

With respect to the two firewater pump engines installed in 1988, USAF has agreed to limit hours of operation to no more than 1,000 hours per year. With the operational limits, the potential to emit NO_X will be less than 2 tons per year. As such, any add on controls will be economically prohibitive for an emission unit with insignificant emissions.

4.3 BACT Determination for CO

The 1988 power plant upgrade project resulted in emissions greater than the PSD applicability threshold for CO. The proposed post 2002 project does not result in emissions increase beyond PSD thresholds for CO.

Table 4.3-1: Summary of CO BACT for Diesel Engines

Applicable Controls	Emission Units	Technically Feasible	Economically Feasible	BACT
Selective Non-Catalytic Reduction (SNCR) (NOxTECH system)	Cooper Bessemer Engines	Yes	No	N/A
	Firewater pumps	Yes	No	N/A
Oxidation Catalyst	Cooper Bessemer Engines	Yes	Yes	Yes
	Firewater pumps	No	No	N/A
SCONOx™ System	All	No	N/A	N/A
Good Combustion Practice (GCP)	Cooper Bessemer Engines	Yes	Yes	No
	Firewater pumps	Yes	Yes	Yes

4.3.1 CO BACT Analysis for the Cooper Bessemer Diesel Electric Generators

USAF evaluated several CO control methods as BACT for the Cooper Bessemer primary generators and the two firewater pump engines installed in 1988. The specific options and an evaluation of results are summarized below, and discussed in detail in this section.

Step 1 – Identify All Control Technologies

Ensuring complete combustion of the fuel limits CO formation. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. In general methods used to minimize NOx formation during combustion could increase CO emissions. USAF identified three control technologies for control of CO that are applicable to the emission units at EAS. In general, the Department concurs with USAF's identification of applicable control technologies.

Step 2 – Eliminate the Technically Infeasible Options

USAF eliminated from consideration the SCONOx™ as technically infeasible since no units in the 3 MW size range have been operated or permitted using SCONOx™ for CO control.

Step 3 – Rank the Remaining Control Technologies by Control Effectiveness

USAF ranked the Cooper Bessemer engines by control effectiveness, expressed as percent reduction in CO from the base case and emission in tons per year after application of the control option, is shown below. The base case is the configuration of the engine as installed in 1988.

Table 4.3-2: CO Control Effectiveness for the Cooper Bessemer Engines

Rank No.	Control Option	Uncontrolled actual emissions (tpy)	Total NOx removed	Emission Rate (tpy)	Percent Reduction (%)	Cost $/ton removed	
						Applicant Estimate[1]	Dept Revised
1	NOxTECH	194	155	39	80	44,322	19,296
2	Oxidation catalyst	194	155	39	80	3,795	3,117
3	GCP	194	0	194	0		

[1] The applicant did not provide CO cost estimates using HMS and TRACES costs estimates. The Department extrapolated the USAF's NOX cost estimate to determine CO cost estimates.

USAF provided detailed discussion of the economic, environmental, and energy impacts of each control option in the application and addenda. Tables 4-4 through 4-17, Addendum 1, March 17, 2003 includes cost estimates for the add-on controls listed above.

Step 4 – Evaluate the Most Effective Controls and Document Results

The NOxTECH as described above, is a type of selective non-catalytic reduction that reduces NOx selectively, while reducing CO concurrently, in one process without solid catalysts. The process is autocatalytic and autothermal. Autocatalysis is a type of reaction in which one of the products of reaction acts as catalyst. Autothermal is another type of reaction that has autocatalytic behavior.

The Oxidation catalysts involve the oxidation of CO using a catalyst.

NOxTECH and Oxidation catalyst are equally effective controls applicable to EAS's Cooper Bessemer engines as shown above with 80% reduction of CO. The Department agrees with the selection of the most effective controls.

Step 5 – Proposed CO BACT for the Cooper Bessemer engines

As shown in Table 4.1.2 above, the cost associated with NOxTECH is prohibitive. Option 2 is economically feasible contingent upon SCR/Oxidation for NO_X reduction. The Department finds that an emission rate achievable with Oxidation catalyst (Option 2) to be BACT on the Cooper Bessemer diesel generator. An emission rate of 4.4 lb/hour is representative of the selected BACT option.

Condition 18.1 of the permit requires the Cooper Bessemer primary engines to meet the 4.4 lb/hour CO limit representative of BACT. Condition 18.1b requires source testing to be carried out concurrently with NO_X Continuous Emission Monitoring System Relative Accuracy Test Audit requirements. The results must be reported as indicated in permit Section 11.

4.4 BACT Determination for SO_2

In 1995 EAS changed fuel oil from DF-2 (fuel sulfur content 0.15%) to JP-8 (fuel sulfur 0.3%). The fuel switch in 1995 did not result in net emission increase of SO_2 beyond the PSD thresholds. However, PSD review is triggered for SO_2 from accumulation of increases since the 1988 PSD trigger date.

Step 1 – Identify All Control Technologies

Sulfur dioxide emissions from combustion units are a result of sulfur in the fuel oil. The SO_2 further combines with water to form sulfuric acid and diammonium sulfate. During the combustion process most of the sulfur will be converted to sulfur dioxide. EAS proposes to use fuel oil containing a low sulfur less than 0.3% of sulfur. Yet the small amount of sulfur will be oxidized to form sulfur dioxide.

USAF identified flue gas desulfurization (FGD) and use of low sulfur fuel as control of SO_2 applicable to the emission units at EAS. In general, the Department concurs with USAF's identification of applicable control technologies.

Step 2 – Eliminate the Technically Infeasible Options

USAF eliminated from consideration flue gas desulfuration. FGD uses an alkali solution in a scrubber to remove sulfur compounds from the flue gases of combustion units. This technology has not been applied to diesel fired IC engines and not technologically feasible for boilers smaller than 100 MMBtu/hr.

Step 3 – Rank the Remaining Control Technologies by Control Effectiveness

Low sulfur fuel is the only feasible control technology for SO2 and control for the emission units.

Step 4 – Evaluate the Most Effective Controls and Document Results

EAS underwent a fuel switch from DF-2 to DF-8 in 1995 as a result of the Department of Defense (DOD) fuel procurement policy. Based on the DOD fuel procurement policy all installations will utilize a standard fuel. The DOD fuel contract specification for ground-based equipment is DF-8 with maximum fuel sulfur content of 0.3% by weight. The specification is the same for all military users and cannot be changed for EAS. The costs associated with procuring alternative fuel at a remote location like Shemya Island would be prohibitive.

Step 5 – Proposed SO_2 BACT for the Cooper Bessemer engines

The Department finds that no controls for SO_2 to be BACT for post 2002 equipment.

5. AMBIENT AIR QUALITY IMPACT ANALYSIS

PSD applicants are required under 18 AAC 50.310(d)(2) to submit predictions of the project's impact on air quality for the air pollutants that triggered PSD review. In a similar manner, applicants of proposals classified under 18 AAC 50.300(h)(2) must also submit an air quality impact analysis per 18 AAC 50.310(n)(2). The Department can also request an air quality analysis under the discretionary provision listed in 18 AAC 50.310(c)(5). Applicants use computer analysis (modeling) to predict the air quality impacts from their proposed emission units. PSD applicants may also be required to measure local air pollution levels (ambient air quality monitoring data), and estimate the impact from their stationary source on select "Air Quality Related Values".

USAF was required to submit an air quality analysis for NO_2, SO_2, PM-10 and CO, which they provided as part of their application. They also provided an Air Quality Related Value (AQRV) analysis, as well as an assessment regarding the monitoring data requirement. Exhibit D contains a memorandum summarizing USAF's analyses, the Department's findings and conclusions. The findings and conclusions are repeated below, along with several highlighted items.

5.1 Pre-Construction Monitoring

18 AAC 50.310(d)(1) requires PSD applicants to submit ambient monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the predicted ambient impact of the proposal is less than the monitoring thresholds provided in 18 AAC 50.310(e). The requirement only pertains to PSD pollutants. The data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the estimated ambient impact from the proposed project.

USAF modeled the NO_2 and CO impacts for the 1988 PSD project, and the NO_2 and SO_2 impacts for the post-2002 project impacts. They compared the maximum impacts to the monitoring thresholds. The maximum-modeled impacts for both the 1988 and post-2002 PSD projects are provided in Table 5.1.1, along with the monitoring thresholds. All of the project impacts are less than the monitoring thresholds. Therefore, pre-construction monitoring would not have been required in 1988, and is not required for the post-2002 proposal.

Table 5.1.1 – Pre-Construction Monitoring Assessment

Air Pollutant	Avg. Period	1988 PSD Project Impact ($\mu g/m^3$)	Post-2002 PSD Project Impact ($\mu g/m^3$)	Monitoring Threshold ($\mu g/m^3$)
NO_2	Annual	11	5	14
SO_2	24-hour	not applicable	12	13
CO	8-hr	62	Not applicable	575

5.2 Ambient Impact Analysis

The Department's goal for the ambient air quality review is to determine whether the proposed project emissions will cause or contribute to a violation of the ambient air quality standards established in 18 AAC 50.010. These air quality standards were set by the U.S. Environmental Protection Agency (EPA) and the Department to protect human health and welfare. In addition, EPA established the maximum allowable increases (increments) as listed in 18 AAC 50.020 to prevent significant deterioration of air quality in areas that meet ambient air quality standards.

USAF used EPA's *Industrial Source Complex Short-Term 3* (ISCST3) model to predict the ambient NO_2, SO_2, PM-10 and CO air quality impacts from the emission units listed in the permit application. However, they used actual emissions, rather than allowable emissions, to model the *projected* annual average impacts from the *existing* EAS emission units. This approach is inconsistent with past Department practice of using allowable emissions to estimate the future annual average impacts from existing emission units.

According to Table 9-2 of EPA's *Guideline on Air Quality Models*, actual emissions can be used "*if* the emissions from the existing stationary source will not be affected by the modification" (emphasis added). The clause implies that actual emissions may be used only if there will not be any change in operation for the existing emission units. However, it is very clear from the remaining text that allowable emissions should be used if there will, or could be, increased operation of the existing emission units. For this reason, the Department's standard practice is for applicants to model the future allowable emissions from their existing emission units. Using this approach to demonstrate compliance with the State's air quality standards and increments ensures that the applicant can have full operational flexibility, without creating an adverse air quality impact. In regards to EAS, the use of allowable emissions is especially warranted considering the potential for increased operations associated with the likely growth of National Security activities.

USAF addressed the Department's concern by presenting two AAAQS demonstrations as a surrogate to revising the entire analysis using allowable emissions for every emission unit. The first demonstration used the as-modeled results, which is based on actual emissions for the emission units existing in 1980 (referred by USAF as a "baseline" unit) and allowable emissions for the "post-baseline" emission units.[1] The second demonstration included an adjustment to the "baseline" impact. USAF multiplied the maximum impact from the "baseline" emission units by the ratio of total allowable to total actual emissions (2.86). They then added this adjusted value to the maximum-modeled impact from the post-baseline activities. The Department considers this approach as an adequate surrogate to modeling the true allowable emissions from each emission unit. The results from both approaches are provided in this chapter.

SO_2 emissions are directly related to the amount of sulfur in the fuel. USAF uses distillate fuels at EAS to operate their combustion units. They are currently using, and plan to continue using, DS-8 with a maximum fuel sulfur content of 0.3 percent, by weight. Prior to 1995, USAF used DF-2 of sulfur 0.15 percent, by weight.

The maximum-modeled NO_2, SO_2, PM-10 and CO AAAQS impacts are shown in Table 5.2.1. The adjusted impacts are provided in Table 5.2.2. The background concentrations, total impacts and AAAQS are also provided in both tables. In both approaches, the total impacts are less than the AAAQS.

Table 5.2.1 – Maximum AAAQS Impacts
(Using actual emissions for the existing emission units)

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	Total Impact: Max Conc. Plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
NO_2	Annual	33	4	**37**	100
PM-10	24-hour	31	33	**64**	150
	Annual	1.2	6.5	**8**	50
SO_2	3-hr	215	13	**228**	1300
	24-hr	76	5.2	**81**	365
	Annual	9	2.6	**12**	80
CO	1-hr	2,920	3,100	**6,020**	40,000
	8-hr	1,004	1,500	**2,504**	10,000

[1] The term "baseline" can have a variety of meanings in air quality permitting. The 611 ASG used the term as the starting point for tracking the stationary source modifications, to determine when the modifications would have required PSD review. The starting point for tracking these modifications is listed in 18 AAC 50.300(h)(3)(A) as August 7, 1980. In modeling applications, "baseline" typically refers to the emission unit inventory and actual air quality concentrations in existence during the "baseline date" established for the given Air Quality Control Region. The baseline dates for each Air Quality Control Region are listed in Table 2 of 18 AAC 50.020(a). EAS is in the South Central Alaska Intrastate Air Quality Control Region. Therefore, the SO_2 and PM-10 baseline dates are October 26, 1979 and the NO_2 baseline date is February 8, 1988. In this context, the PM-10 and SO_2 "baseline concentrations" also include the *allowable* emissions from major stationary sources for which construction commenced before January 6, 1975, but was not in operation by the baseline date, while otherwise excluding the *actual* emissions from a major stationary source for which construction commenced on or after January 6, 1975 – per 18 AAC 50.020(e)(1). The 611 ASG stated the 1980 "baseline" inventory is identical to the emission unit inventory in existence during the 1979 SO_2 and PM-10 baseline date. Therefore, the 611 ASG used the 1980 baseline inventory to estimate the SO_2 and PM-10 PSD baseline concentrations. The Department accepts this assumption and notes that there is no evidence to show that the 1980 inventory substantially differs from the either the 1979 or 1975 inventories.

Table 5.2.2 – Adjusted Maximum AAAQS Impacts

Air Pollutant	Avg. Period	Maximum Modeled Impact (µg/m³) Baseline Sources	Adjusted Baseline	Post-2002 Units	Bkgd Conc (µg/m³)	Total Impact (µg/m³)	Ambient Standard (µg/m³)
NO_2	Annual	16.3	46.6	17.0	4	**68**	100
PM-10	24-hour	20.2	57.8	28.8	33	**120**	150
	Annual	0.2	0.6	1.1	6.5	**8**	50
SO_2	3-hr	29.1	83.2	215	13	**311**	1300
	24-hr	16.2	46.3	76.0	5.2	**128**	365
	Annual	0.2	0.6	8.8	2.6	**12**	80
CO	1-hr	933	2,668	2,208	3,100	**7,976**	40,000
	8-hr	328	938	759	1,500	**3,197**	10,000

The maximum increment impacts for the 1988 PSD project are provided in Table 5.2.3. The maximum increment impacts for the post-2002 PSD project are provided in Table 5.2.4. The Class II increment standards are provided in both tables. All of the maximum impacts are less than the applicable Class II standard.

Table 5.2.3 – 1988 PSD Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Class II Increment Standard (µg/m³)
NO_2	Annual	**11**	25

Table 5.2.4 – Post-2002 PSD Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Class II Increment Standard (µg/m³)
NO_2	Annual	**17**	25
PM-10	24-hour	**29**	30
	Annual	**1.1**	17
SO_2	3-hr	**215**	512
	24-hr	**76**	91
	Annual	**9**	20

It is important to note that since ambient concentrations vary with distance from each emission unit, the maximum values shown represent the highest value that may occur somewhere in the local airshed. They do *not* represent the highest concentration that could occur at *all* locations in the area.

5.3 Analysis of Air Quality Related Values

As required under 18 AAC 50.310(d)(4), USAF submitted an analysis of the potential impact from EAS on the air quality related values for visibility, soil, vegetation, noise and odor. A Class I assessment was not required since the nearest Class I areas are over 1600 km away.

USAF's analysis adequately demonstrates that there are no adverse visibility, soil, vegetation, noise and odor impacts. Additional details regarding the analysis may be found in the application and in the Department's review memorandum provided in Exhibit D.

5.4 Conclusion

The NO_2, SO_2, PM-10 and CO emissions associated with operating the stationary source within the requested operating limits will not cause or contribute to a violation of the ambient air quality standards provided in 18 AAC 50.010, or the maximum allowable increases (increments) provided in 18 AAC 50.020. The project should not lead to adverse visibility, soil, vegetation, noise, or odor impacts. USAF's modeling analysis fully complies with the showing requirements of 18 AAC 50.315(e)(2). USAF conducted their modeling analysis in a manner consistent with EPA's *Guideline on Air Quality Models.*

The Department has included Conditions 6, 7 and 8 in the permit to ensure compliance with the ambient air quality standards and increments. Condition 6 specifies the type of fuels authorized to be burned in the emission units. Condition 7 requires USAF to limit the maximum sulfur content of the fuel to 0.3 percent by weight. Condition 8 limits the operating hours of the emergency backup generators, firewater pumps and barrier engines to owner requested limits and those imposed as BACT.

6. PERMIT ADMINISTRATION

The Department has prepared Air Quality Control (AQC) Construction Permit No. 307CP01 for the USAF for the Eareckson Air Station. Permit No. 307CP01 authorizes USAF to install and operate the existing emission units and proposed emission units and operate EAS under PSD regulations. The decision documents have been prepared in accordance with the provisions of 18 AAC 50.315 and AS 46.14.170.

7. CONSISTENCY WITH ALASKA COASTAL MANAGEMENT PROGRAM

Project consistency with the Alaska Coastal Management plan is being carried out by the Department of Natural Resources, Office of Project Management and Permitting (OPMP). USAF submitted a coastal project questionnaire to the OPMP. The questionnaire identifies the need for USAF to apply only for an Air Quality Control Construction and Operating Permits. OPMP initiated project review on August 20, 2003.

8. FINAL PERMIT DECISION

USAF's construction permit application for the Eareckson Air Station satisfies the requirements listed in 18 AAC 50.310. USAF's application demonstrates that the EAS will meet all applicable requirements in 18 AAC 50.315(e). Therefore, in accordance with 18 AAC 50.315(f), the Department is issuing a final construction permit for Eareckson Air Station.

EXHIBIT A
Table A1. Emission Unit Inventory and Associated Emissions

Unit No	Unit Location	Unit Description	Fuel type	Op Limit Hr/yr	Install/ Modify Date	Rating/Size	PM-10	SO_2	NO_X	CO	VOC
Main Generators											
1	3049-1	Cooper LSV16GDT #1	DF-8		Pre 1980	3,000 kW	1.1	42.7	42.5	19.3	11.3
2	3049-2	Cooper LSV16GDT #2	DF-8		Pre 1980	3,000 kW	1.1	42.7	42.5	19.3	11.3
3	3049-3	Cooper LSV16GDT #3	DF-8		Pre 1980	3,000 kW	1.1	42.7	42.5	19.3	11.3
4	3049-4	Cooper LSV16GDT #4	DF-8		Pre 1980	3,000 kW	1.1	42.7	42.5	19.3	11.3
5	3049-5	Cooper LSV16GDT #5	DF-8		10/1988	3,000 kW	1.1	42.7	42.5	19.3	11.3
6	3049-6	Cooper LSV16GDT #6	DF-8		10/1988	3,000 kW	1.1	42.7	42.5	19.3	11.3
Firewater Pump Engines											
7	523	Firewater Pump (Detroit #1)	DF-8		Pre 1980	2,100 hp	6.4	22.3	220.8	50.6	5.9
8	523	Firewater Pump (Detroit #2)	DF-8		Pre 1980	2,100 hp	6.4	22.3	220.8	50.6	5.9
9	523	Firewater Pump (Detroit #3)	DF-8		Pre 1980	2,100 hp	6.4	22.3	220.8	50.6	5.9
10	523	Firewater Pump (Detroit #4)	DF-8		Pre 1980	2,100 hp	6.4	22.3	220.8	50.6	5.9
11	755	Firewater Pump Unit #1	DF-8		Unknown	30 hp	0.3	0.3	4.1	0.9	0.3
12	755	Firewater Pump Unit #2	DF-8		Unknown	30 hp	0.3	0.3	4.1	0.9	0.3
13	3057	Firewater Pump (Detroit #5)	DF-8	1000	10/1988	186 hp	0.2	0.2	2.9	0.6	0.2
14	3057	Firewater Pump (Detroit #6)	DF-8	1000	10/1988	230 hp	0.3	0.3	3.6	0.8	0.3
15	4011	Firewater Pump	DF-8	500	1/1997	175 hp	0.1	0.1	1.4	0.3	0.1
16	3049	Firewater Pump Unit #1	DF-8	500	10/2003	160 hp	0.1	0.1	1.2	0.3	0.1
17	3049	Firewater Pump Unit #2	DF-8	500	10/2003	160 hp	0.1	0.1	1.2	0.3	0.1
18	84-110	Firewater Pump Unit #1	DF-8	500	2003	1,100 hp	0.2	0.7	6.6	1.5	0.2
19	84-110	Firewater Pump Unit #2	DF-8	500	2004	1,100 hp	0.2	0.7	6.6	1.5	0.2
20	523	Firewater Pump Unit #1	DF-8	500	2004	1,100 hp	0.2	0.7	6.6	1.5	0.2
21	523	Firewater Pump Unit #2	DF-8	500	2004	1,100 hp	0.2	0.7	6.6	1.5	0.2
22	523	Firewater Pump Unit #3	DF-8	500	2004	1,100 hp	0.2	0.7	6.6	1.5	0.2
23	523	Firewater Pump Unit #4	DF-8	500	2004	1,100 hp	0.2	0.7	6.6	1.5	0.2
Backup Generators											
24	629	EB Generator (Unknown)	DF-8		Pre 1980	62 kW	0.8	0.9	11.3	2.4	0.9
25	76-529	EB Generator	DF-8	500	1/1981	30 kW	0.0	0.0	0.3	0.1	0.0
26	42	Generator	DF-8	500	1/1986	20 kW	0.0	0.0	0.2	0.0	0.0
27	76-558	EB Generator (Mitsubishi)	DF-8	500	1/1987	40 kW	0.0	0.0	0.4	0.1	0.0
28	222	EB Generator	DF-8	500	1/1988	50 kW	0.0	0.0	0.5	0.1	0.0
29	223	EB Generator	DF-8	500	4/1988	35 kW	0.0	0.0	0.4	0.1	0.0
30	3049-7	EB Generator (Caterpillar)	DF-8	300	1/1990	225 kW	0.1	0.1	1.4	0.3	0.1
31	558	EB Generator (Unknown)	DF-8	500	1/1991	40 kW	0.0	0.0	0.4	0.1	0.0
32	4014-1	EB Generator (Mitsubishi #1)	DF-8	300	1/1991	350 kW	0.2	0.2	2.2	0.5	0.2
33	4014-2	EB Generator (Mitsubishi #2)	DF-8	300	1/1991	350 kW	0.2	0.2	2.2	0.5	0.2
34	600	EB Generator (Caterpillar)	DF-8	300	1/1991	283 kW	0.1	0.1	1.8	0.4	0.1

Unit No	Unit Location	Unit Description	Fuel type	Op Limit Hr/yr	Install/ Modify Date	Rating/Size	PM-10	SO_2	NO_x	CO	VOC
35	609	EB Generator	DF-8	500	1/1995	100 kW	0.1	0.1	1.0	0.2	0.1
36	754	EB Generator	DF-8	300	1995	400 kW	0.2	0.2	2.5	0.5	0.2
37	76-529	EB Generator	DF-8	500	1995	30 kW	0.0	0.0	0.3	0.1	0.0
38	76-557	EB Generator	DF-8	500	1995	20 kW	0.0	0.0	0.2	0.0	0.0
39	110	EB Generator	DF-8	300	1/1996	350 kW	0.2	0.2	2.2	0.5	0.2
40	628	EB Generator (Unknown)	DF-8	300	1/1998	275 kW	0.1	0.1	1.7	0.4	0.1
41	718	EB Generator (Motor Works)	DF-8	500	1/2000	50 kW	0.0	0.0	0.5	0.1	0.0
42	775	EB Generator (Caterpillar)	DF-8	500	1/2001	500 kW	0.1	0.4	4.0	0.9	0.1
43	527	EB Generator	DF-8	500	Unknown	40 kW	0.0	0.0	0.4	0.1	0.0
44	76-524	EB Generator (ILS Unit #1)	DF-8	500	2003	600 kW	0.1	0.5	4.8	1.1	0.1
45	76-522	EB Generator (ILS Unit #2)	DF-8	500	2003	600 kW	0.1	0.5	4.8	1.1	0.1
Emergency Barrier Engines											
46	74-041-1	Aircraft Barrier Engine (Wisconsin V465 #1)	MUR		1/2000	65.9 hp	0.0	0.0	0.2	7.2	0.4
47	74-041-2	Aircraft Barrier Engine (Wisconsin V465 #2)	MUR		1/2000	65.9 hp	0.0	0.0	0.2	7.2	0.4
48	74-041-3	Aircraft Barrier Engine (Wisconsin V465 #3)	MUR		1/2000	65.9 hp	0.0	0.0	0.2	7.2	0.4
49	74-041-4	Aircraft Barrier Engine (Wisconsin V465 #4)	MUR		1/2000	65.9 hp	0.0	0.0	0.2	7.2	0.4
50	74-041-1	Aircraft Barrier Engines	MUR		2005	65.9 hp	0.0	0.0	0.2	7.2	0.4
51	74-041-2	Aircraft Barrier Engines	MUR		2005	65.9 hp	0.0	0.0	0.2	7.2	0.4
52	74-041-3	Aircraft Barrier Engines	MUR		2005	65.9 hp	0.0	0.0	0.2	7.2	0.4
53	74-041-4	Aircraft Barrier Engines	MUR		2005	65.9 hp	0.0	0.0	0.2	7.2	0.4
Boilers											
54	110-1	Boiler	DF-8		1/1982	0.607 MMBtu/hr	0.0	0.9	0.4	0.1	0.0
55	110-2	Boiler	DF-8		1/1982	0.607 MMBtu/hr	0.0	0.9	0.4	0.1	0.0
56	753-1	Boiler (Kewanee #1)	DF-8		1/1990	2.05 MMBtu/hr	0.1	3.0	1.4	0.4	0.0
57	753-2	Boiler (Kewanee #2)	DF-8		1/1990	2.05 MMBtu/hr	0.1	3.0	1.4	0.4	0.0
58	754	Boiler (Kewanee)	DF-8		1/1990	2.05 MMBtu/hr	0.1	3.9	1.8	0.5	0.0
59	754	Boiler (Kewanee)	DF-8		1/1990	2.66 MMBtu/hr	0.1	3.9	1.8	0.5	0.0
60	1001	Boiler (Weil McCain)	DF-8		1/1991	0.405 MMBtu/hr	0.0	0.6	0.3	0.1	0.0
61	3045	Boiler (Unknown)	DF-8		1/1992	0.528 MMBtu/hr	0.0	0.7	0.3	0.1	0.0
62	600	Boiler (Cleaver Brooks)	DF-8		1/1994	4.184 MMBtu/hr	0.2	6.2	2.9	0.7	0.0
63	752-1	Boiler (Unknown)	DF-8		1/1994	2.01 MMBtu/hr	0.1	3.0	1.4	0.3	0.0
64	752-2	Boiler (Unknown)	DF-8		1/1994	2.01 MMBtu/hr	0.1	3.0	1.4	0.3	0.0
65	626	Boiler	DF-8		1994	0.25 MMBtu/hr	0.0	0.4	0.2	0.0	0.0
66	626	Boiler	DF-8		1994	0.14 MMBtu/hr	0.0	0.2	0.1	0.0	0.0
67	599	Boiler (Unknown)	DF-8		1/1995	5.05 MMBtu/hr	0.2	7.4	3.5	0.9	0.1
68	755	Boiler (Unknown)	DF-8		1/1995	2.05 MMBtu/hr	0.1	3.0	1.4	0.4	0.0
69	755	Boiler (Unknown)	DF-8		1/1995	2.66 MMBtu/hr	0.1	3.9	1.8	0.5	0.0
70	611	Boiler (Unknown)	DF-8		1/1995	1.29 MMBtu/hr	0.0	1.9	0.9	0.2	0.0

Unit No	Unit Location	Unit Description	Fuel type	Op Limit Hr/yr	Install/ Modify Date	Rating/Size	PM-10	SO_2	NOx	CO	VOC
71	743-1	Boiler (Unknown)	DF-8		1/1996	3.35 MMBtu/hr	0.1	4.9	2.3	0.6	0.0
72	743-2	Boiler (Unknown)	DF-8		1/1996	3.35 MMBtu/hr	0.1	4.9	2.3	0.6	0.0
73	618	Boiler	DF-8		1996	0.442 MMBtu/hr	0.0	0.7	0.3	0.1	0.0
74	600	Boiler (Cleaver Brooks)	DF8/ Reclaimed Oil		1/1998	8.369 MMBtu/hr	2.1	11.8	5.7	4.2	0.7
75	598	Boiler (Burnham)	DF-8		7/2002	5.657 MMBtu/hr	0.2	7.4	3.5	0.9	0.1
76	598	Boiler	DF-8		Unknown	0.704 MMBtu/hr	0.0	1.0	0.5	0.1	0.0
77	729	Boiler	DF-8		Unknown	0.399 MMBtu/hr	0.0	0.6	0.3	0.1	0.0
78	755	Boiler (Unknown)	DF8/ Reclaimed Oil		2003	2.79 MMBtu/hr	0.7	3.9	1.9	1.4	0.2
79	597	Boiler (Unknown #1)	DF-8		2005	2.01 MMBtu/hr	0.1	3.0	1.4	0.3	0.0
80	597	Boiler (Unknown #2)	DF-8		2005	2.01 MMBtu/hr	0.1	3.0	1.4	0.3	0.0
81	754	Boiler (Unknown)	DF-8		2005	2.65 MMBtu/hr	0.1	3.9	1.8	0.5	0.0
82	754	Boiler (Unknown)	DF-8		2005	2.65 MMBtu/hr	0.1	3.9	1.8	0.5	0.0
Furnaces and Incinerators											
83	743	Paint Spray Booth	DF-8		10/2002		0.7	0.0	0.0	0.0	4.8
84	619	Solid Waste Incinerator	DF8/Solid Waste	1,000	2005	750 lb/hr	0.8	0.3	0.6	0.8	0.8
						Total emissions	**44.6**	**450.3**	~~**1286.3**~~	~~**414.5**~~	**115.1**

2807.9 725.0

Assessable emissions 4143

Emission Factors (EF)

	PM-10	SO_2	NOx	CO	VOC
IC Engine					
Diesel fired < 600 hp AP-42 Table 3.3-1 (lb/hp-hr)	0.0022	0.0039	0.031	0.00668	0.0025141
Diesel fired > 600 hp AP-42 Table 3.4-1 (lb/hp-hr)	0.0007	0.004045	0.024	0.0055	0.00064155
Cooper Bessemer Engines (lb/hr)*	0.242				
MUR Fired IC Engine < 600 hp	0.000721	0.000591	0.011	0.439	0.021591
Boilers < 100 MMBtu/hr					
No. 2 oil fired AP-42 Tables 1.3-1 & 1.3-7 (lb/10^3 gal)	1.08	142S	20	5	0.34
No. 6 oil fired AP-42 Tables 1.3-1 & 1.3-5 (lb/10^3 gal)	2.2	157S	55	5	1.13
Used oil fired AP-42 Table 1.11-1, 1.11-2 & 1.11-3 (lb/10^3 gal)	64A	147S	19	5	1.0

* - Source test results;
A - ash content (determined to be 0.36% from fuel analysis);
S – fuel sulfur content;

Table A2. Pollutant Emission Rate Changes Since 1980, tons/yr

Project/Physical Change	Bldg	Year	Net emission Increase/Decrease (tons/yr)				
			NOx	SO_2	CO	VOC	PM-10
Added 30 kW backup gen set	76-529	1981	0.3	0.0	0.1	0.0	0.0
Removed 5 kW backup gen set	730	1981	0.0	0.0	0.0	0.0	0.0
Removed 2.0 MMBtu/hr boiler	726	1981	-0.1	0.0	0.0	0.0	0.0
Removed 8 kW backup gen set	41	1982	0.0	0.0	0.0	0.0	0.0
Added 8.9 MMBtu/hr boiler	600	1982	5.7	6.1	1.4	0.1	0.3
Added two 0.607 MMBtu/hr boilers	110	1982	0.8	0.8	0.2	0.0	0.0
Upgraded 30 kW White to 75 kW Kato	718	1983	0.5	0.0	0.1	0.0	0.0
Added 0.07 MMBtu/hr boiler	719	1983	0.0	0.0	0.0	0.0	0.0
Removed 30 kW backup gen set	3016	1984	0.0	0.0	0.0	0.0	0.0
Added 20 kW backup gen set	76-557	1984	0.2	0.0	0.0	0.0	0.0
Added 260 kW Waukesha backup gen set	110	1984	1.6	0.1	0.3	0.1	0.1
Added two 1.3 MMBtu/hr boilers	752	1985	1.7	1.8	0.4	0.0	0.1
Added 20 kW backup gen set	42	1986	0.2	0.0	0.0	0.0	0.0
Added and replaced BAK-13 barrier arrestors, 2 MUR engines[1]	74-041	1986	0.8	0.0	26.2	1.4	0.0
Added rock crusher	N/A	1986	0.5	0.1	0.2	0.0	0.3
Added 100 kW backup gen set	625	1986	1.0	0.0	0.2	0.1	0.1
Added 0.14 MMBtu/hr boiler	28	1986	0.1	0.1	0.0	0.0	0.0
Upgraded two 5 MMBtu/hr boilers to 9.7 MMBtu/hr units	702	1986	16.1	12.2	2.8	0.3	0.8
Upgraded 400 k W Chicago Pneumatic to 500 kW Cummins	775	1987	3.9	0.1	0.9	0.1	0.1
Added 40 kW backup gen set at VORTAC	76-558	1987	0.4	0.1	0.1	0.0	0.0
Added two 1.6 MMBtu/hr boilers	522	1987	2.0	2.2	0.5	0.0	0.1
Added 400 kW backup gen set	754	1987	2.5	0.1	0.5	0.2	0.2
Added 100 kW backup gen set	600	1987	1.0	0.0	0.2	0.1	0.1
Added 20 kW backup gen set	611	1987	0.2	0.0	0.0	0.0	0.0
Added 0.25 MMBtu/hr boiler	114	1987	0.2	0.1	0.0	0.0	0.0
Accumulated emission changes since 1980			**39.6**	**23.8**	**34.1**	**2.4**	**2.2**
Add #5 & #6 C-B 3,000 kW Gen Sets, remove 8 Alco Worthington 1,250 and 1,300 kW gen sets	3049, 3051	1988	636.8	5.8	138.3	17.3	-5.2
Added two (186 and 230 hp) firepumps	3057	1988	56.5	0.4	12.2	4.6	4.0
Added 30 kW backup gen set	3013	1988	0.3	0.0	0.1	0.0	0.0
Added 60 kW backup gen set	727	1988	0.6	0.0	0.1	0.1	0.1
Replaced 35 kW backup gen set with same[1]	223	1988	0.4	0.0	0.1	0.0	0.0
Upgraded 60 kW Cummins to 100 kW backup gen set	221	1988	1.0	0.1	0.2	0.1	0.1
Replaced 60 kW backup gen set with 50 kW unit	222	1988	0.5	0.0	0.1	0.0	0.0
Accumulated emissions from Power Plant Additions			**696.1**	**6.3**	**151.1**	**22.1**	**-1.0**
Removed 60 kW backup gen set	232	1989	0.0	0.0	0.0	0.0	0.0
Removed 30 kW backup gen set	490	1989	0.0	0.0	0.0	0.0	0.0

Project/Physical Change	Bldg	Year	Net emission Increase/Decrease (tons/yr)				
			NOx	SO_2	CO	VOC	PM-10
Removed 150 kW backup gen set	110	1989	-0.1	0.0	0.0	0.0	0.0
Added 35 kW Cummins backup gen set	731	1989	0.4	0.0	0.1	0.0	0.0
Added 225 kW backup gen set	3049	1990	1.5	0.0	0.3	0.1	0.1
Added 5.05 MMBtu/hr Boiler	598	1990	3.2	0.6	0.8	0.1	0.2
Replaced 20 kW Perkins backup gen set with 100 kW Cummins	611	1990	1.0	0.1	0.2	0.1	0.1
Added 86 kW backup gen set	729	1990	0.9	0.1	0.2	0.1	0.1
Added 60 kW backup gen set	729	1990	0.6	0.0	0.1	0.1	0.0
Added two 2.05 MMBtu/hr Boilers	753	1990	2.6	2.8	0.7	0.0	0.1
Added 2.05 MMBtu/hr Boiler	754	1990	1.3	1.4	0.3	0.0	0.1
Added 2.66 MMBtu/hr Boiler	754	1990	2.3	1.8	0.4	0.1	0.1
Replaced two 0.392 MMBtu/hr Consumate C-500 units with single Keller solid waste incinerator	619	1990	-0.1	-0.1	0.0	0.0	0.0
Removed 275 kW backup gen set	4010	1991	0.0	0.0	0.0	0.0	0.0
Replaced two 275 kW backup gen sets with 350 kW units	4014	1991	4.6	0.0	1.0	0.4	0.3
Added two 100 kW backup gen sets	3051	1991	2.1	0.0	0.4	0.2	0.1
Added 3 kW backup gen set	3051	1991	0.0	0.0	0.0	0.0	0.0
Added 60 kW backup gen set	3051	1991	0.6	0.0	0.1	0.1	0.0
Added 30 kW backup gen set	3051	1991	0.3	0.0	0.1	0.0	0.0
Added 30 kW backup gen set	3075	1991	0.3	0.0	0.1	0.0	0.0
Added 40 kW backup gen set	558	1991	0.4	0.0	0.1	0.0	0.0
Added 283 kW backup gen set	600	1991	1.9	0.1	0.4	0.2	0.1
Added two 2.01 MMBtu/hr Boilers	597	1991	2.8	2.8	0.7	0.1	0.2
Added 0.405 MMBtu/hr Boiler	1001	1991	0.3	0.3	0.1	0.0	0.0
Added 0.528 MMBtu/hr Boiler	3045	1992	0.3	0.4	0.1	0.0	0.0
Overhauled Primary Generator #1[3]	3049	1992	0.0	0.0	0.0	0.0	0.0
Added 260 kW Caterpillar backup gen set	618	1992	1.8	0.0	0.4	0.1	0.1
Added 250 kW backup gen set	628	1993	1.7	0.0	0.4	0.1	0.1
Overhauled Primary Generator #3[3]	3049	1993	0.0	0.0	0.0	0.0	0.0
Added two 4.18 MMBtu/hr boilers	502	1993	5.3	5.7	0.7	0.0	0.3
Added 0.255 MMBtu/hr boiler	618	1993	0.1	0.2	0.0	0.0	0.0
Removed 35 kW backup gen set	731	1993	0.0	0.0	0.0	0.0	0.0
Removed two 11.6 MMBtu/hr boilers	503	1994	-1.6	-1.5	-0.4	-0.1	-0.2
Removed 0.07 MMBtu/hr boiler	719	1994	0.0	0.0	0.0	0.0	0.0
Added 100 kW backup gen set	490	1994	1.0	0.1	0.2	0.1	0.1
Added 0.808 MMBtu/hr boiler	515	1994	0.6	0.6	0.1	0.0	0.0
Added 0.716 MMBtu/hr boiler	515	1994	0.5	0.5	0.1	0.0	0.0
Added 0.25 MMBtu/hr boiler	626	1994	0.2	0.2	0.0	0.0	0.0

Project/Physical Change	Bldg	Year	Net emission Increase/Decrease (tons/yr)				
			NOx	SO_2	CO	VOC	PM-10
Added 0.14 MMBtu/hr boiler	626	1994	0.1	0.1	0.0	0.0	0.0
Removed 86 kW backup gen set	729	1994	0.0	0.0	0.0	0.0	0.0
Removed 60 kW backup gen set	729	1994	0.0	0.0	0.0	0.0	0.0
Removed 0.5 MMBtu/hr boiler	27	1994	-0.1	0.0	0.0	0.0	0.0
Removed 0.14 MMBtu/hr boiler	28	1994	-0.1	0.0	0.0	0.0	0.0
Removed two 5 MMBtu/hr boilers	4010	1994	-0.6	-0.1	-0.1	0.0	0.0
Removed 260 kW backup gen set	110	1994	-0.1	0.0	0.0	0.0	0.0
Removed 0.25 MMBtu/hr boiler	114	1994	-0.1	0.0	0.0	0.0	0.0
Removed 30 kW backup gen set	132	1994	0.0	0.0	0.0	0.0	0.0
Removed 50 kW backup gen set	220	1994	0.0	0.0	0.0	0.0	0.0
Removed 100 kW backup gen set	221	1994	0.0	0.0	0.0	0.0	0.0
Removed 35 kW backup gen set	223	1994	0.0	0.0	0.0	0.0	0.0
Removed 0.19 MMBtu/hr boiler	452	1994	0.0	0.0	0.0	0.0	0.0
Removed 2.05 MMBtu/hr boiler	490	1994	-0.1	-0.1	0.0	0.0	0.0
Removed 0.167 MMBtu/hr boiler	587	1994	0.0	0.0	0.0	0.0	0.0
Removed 5.05 MMBtu/hr boiler	598	1994	-0.1	-0.1	0.0	0.0	0.0
Removed 3.34 MMBtu/hr boiler	599	1994	0.0	-0.1	0.0	0.0	0.0
Removed 8.9 MMBtu/hr boiler	600	1994	-0.9	-0.6	-0.2	0.0	0.0
Added 4.184 MMBtu/hr boiler	600	1994	2.9	2.1	0.7	0.0	0.2
Removed 0.8 MMBtu/hr boiler	613	1994	-0.1	0.0	0.0	0.0	0.0
Removed 0.405 MMBtu/hr boiler	614	1994	0.0	0.0	0.0	0.0	0.0
Removed 2.34 MMBtu/hr boiler	615	1994	-0.1	-0.2	0.0	0.0	0.0
Removed 0.19 MMBtu/hr boiler	616	1994	-0.1	0.0	0.0	0.0	0.0
Removed two 0.25 MMBtu/hr boilers	617	1994	-0.1	-0.1	0.0	0.0	0.0
Removed 30 kW backup gen set	625	1994	0.0	0.0	0.0	0.0	0.0
Removed 100 kW backup gen set	625	1994	0.0	0.0	0.0	0.0	0.0
Removed 6.5 MMBtu/hr boiler	702	1994	-0.2	0.0	0.0	0.0	0.0
Removed two 9.7 MMBtu/hr reclaimed oil fired boilers	702	1994	-4.6	-2.0	-0.2	-0.1	-0.1
Removed 75 kW backup gen set	718	1994	0.0	0.0	0.0	0.0	0.0
Removed 0.25 MMBtu/hr boiler	731	1994	0.0	0.0	0.0	0.0	0.0
Removed 30 kW backup gen set	3013	1994	0.0	0.0	0.0	0.0	0.0
Removed two 1.6 MMBtu/hr boilers	522	1994	-0.5	-0.6	-0.1	0.0	0.0
Removed two 4.18 MMBtu/hr boilers	502	1994	-0.2	-0.2	0.0	0.0	0.0
Replaced two 1.3 MMBtu/hr boilers with 2.01 MMBtu/hr boilers	752	1994	2.4	2.7	0.6	0.0	0.2
Added 5.05 MMBtu/hr boiler	599	1995	3.5	7.4	0.9	0.1	0.2
Added 2.05 MMBtu/hr boiler	755	1995	1.4	3.0	0.4	0.0	0.1
Added 2.66 MMBtu/hr boiler	755	1995	1.8	3.9	0.5	0.0	0.1

Project/Physical Change	Bldg	Year	Net emission Increase/Decrease (tons/yr)				
			NOx	SO_2	CO	VOC	PM-10
Added 1.29 MMBtu/hr boiler	611	1995	0.9	1.9	0.2	0.0	0.0
Added 0.088 MMBtu/hr boiler	619	1995	0.1	0.1	0.0	0.0	0.0
Added 3.348 MMBtu/hr boiler	743	1995	2.3	4.9	0.6	0.0	0.1
Removed 2.05 MMBtu/hr boiler	490	1995	-0.3	-0.3	-0.1	0.0	-0.2
Removed 0.808 MMBtu/hr boiler	515	1995	-0.1	0.0	0.0	0.0	0.0
Removed 0.716 MMBtu/hr boiler	515	1995	-0.1	0.0	0.0	0.0	0.0
Removed two 2.01 MMBtu/hr DF-8 fired boilers	597	1995	-2.8	-0.6	-0.8	0.0	-0.2
Removed 40 kW backup gen set	558	1995	0.0	0.0	0.0	0.0	0.0
Added 100 kW backup gen set	609	1995	1.0	0.1	0.2	0.1	0.1
Replaced 400 kW backup gen set[1]	754	1995	2.3	0.2	0.5	0.2	0.2
Replaced 30 kw backup gen set[1]	76-529	1995	0.3	0.0	0.1	0.0	0.0
Replaced 20 kW backup gen set[1]	76-557	1995	0.2	0.0	0.0	0.0	0.0
Removed 35 kW backup gen set	232	1995	0.0	0.0	0.0	0.0	0.0
Removed 100 kW backup gen set	490	1995	-0.1	0.0	0.0	0.0	0.0
Removed 100 kW backup gen set	600	1995	0.0	0.0	0.0	0.0	0.0
Removed 20 kW backup gen set	611	1995	0.0	0.0	0.0	0.0	0.0
Removed 100 kW backup gen set	611	1995	0.0	0.0	0.0	0.0	0.0
Removed 60 kW backup gen set	727	1995	0.0	0.0	0.0	0.0	0.0
Removed two 100 kW backup gen sets	3051	1995	-0.4	0.0	-0.1	0.0	0.0
Removed three backup gen sets (3 kW, 60 kW, & 30 kW)	3051	1995	-0.1	0.0	0.0	0.0	0.0
Removed 30 kW backup gen set	3075	1995	0.0	0.0	0.0	0.0	0.0
Accumulated Emissions since power plant additions			**44.1**	**37.5**	**10.8**	**2.1**	**2.6**
Transition to caretaker status/fuel switch to DF-8 from DF-2 (Actuals)	All	1995	-55.7	22.8	-14.7	-1.3	-2.6
Removed Keller Incinerator (Solid Waste)	619	1995	-0.5	-0.6	-0.1	0.0	0.0
Overhauled Primary Generator #4[3]	3049	1995	0.0	0.0	0.0	0.0	0.0
Added 3.35 MMBtu/hr Boiler	743	1996	2.3	4.9	0.6	0.0	0.1
Added 350 kW backup gen set	110	1996	2.2	0.2	0.5	0.2	0.2
Removed rock crushing equipment	N/A	1996	-0.5	-0.1	-0.2	0.0	-0.3
Added 175 hp firepump	4011	1997	1.4	0.1	0.3	0.1	0.1
Replaced a 250 kW backup gen set with a 275 kW unit	628	1998	0.0	0.0	0.0	0.0	0.0
Replaced 0.255 MMBtu/hr boiler with a 0.442 MMBtu/hr boiler	618	1998	0.3	0.6	0.1	0.0	0.0
Modified 8.369 MMBtu/hr boiler to fire reclaimed oil	600	1998	7.7	9.5	1.2	0.2	0.6
Replaced four BAK-13 barrier engines[1]	74-041	2000	0.8	0.0	23.6	1.6	0.0
Reactivate[2] 50 kW backup gen set & relocate ICC & weather obs station	718	2000	0.5	0.0	0.0	0.0	0.4
Overhauled Primary Generator #2[3]	3049	2000	0.0	0.0	0.0	0.0	0.0
Remove 260 kW backup gen set	618	2001	-0.1	0.0	0.0	0.0	0.0

Project/Physical Change	Bldg	Year	Net emission Increase/Decrease (tons/yr)				
			NOx	SO_2	CO	VOC	PM-10
Overhauled Primary Generator #3[3]	3049	2001	0.0	0.0	0.0	0.0	0.0
Repair Primary Generator #2[3]	3049	2002	0.0	0.0	0.0	0.0	0.0
Repaired foundation Primary Generator #6	3049	2001	0.0	0.0	0.0	0.0	0.0
Replaced 500 kW backup gen set with 600 kW unit	775	2001	3.8	0.3	0.9	0.1	0.1
Overhaul Primary Generator #1[3]	3049	2002	0.0	0.0	0.0	0.0	0.0
Overhaul Primary Generator #5[3]	3049	2002	0.0	0.0	0.0	0.0	0.0
Replace 5.05 MMBtu/hr boiler	598	2002	1.2	1.1	0.3	0.1	0.1
Added Paint Spray Booth	743	2002	0.0	0.0	0.0	4.8	0.7
Accumulated emissions since last action			**-36.6**	**38.8**	**12.5**	**5.8**	**-0.6**
Total Emission Change			**743.2**	**106.4**	**208.5**	**32.4**	**3.2**
PSD Significant Threshold Levels			**40.0**	**40.0**	**100.0**	**40.0**	**15.0**

Notes:
For existing operating units, removed, Net Emission Change calculated from post-change potential minus pre-change average actuals.

A. Net Emission Change calculated from post-change potential for units not previously operated or replaced;
B. Fuel switch from DF-2 to DF-8 in 1995 was determined with actual calendar year emissions (pre-conversion year- 1994) and 1995.
C. All added units with criteria pollutant emissions net changes above 0.1 ton/yr threshold are shown in the summary.
D. Period of evaluation extended from Calendar year 1980 until the present year.
E. EB generators, firewater pumps, and aircraft barrier engines have been restricted to operate no more than 500 hr/rolling 12-month period per unit as a PAL.
F. Changes in VOC emissions due to storage tank changes are not tracked.

Footnotes:
[1] Like-kind replacement of existing unit is treated as new installation under recent ADEC and EPA Region X guidance.
[2] Existing equipment brought into service after a period of inactivity.
[3] Periodic overhaul of equipment has been classified as "routine maintenance, repair, and replacement" consistent with recent ADEC and EPA Region X guidance.

Sulfur dioxide emissions revised per ADEC review to reflect DF-2 fuel sulfur content of 0.15% by weight.

EXHIBIT B

Particulate Matter Standards when using Reclaimed Oil

The Department used an AP-42 emission factor and the following equation from 40 CFR 60, Appendix A, Performance Test 19, to determine the grain loading from the engines:

$$\mathbf{E = CF(20.9/(20.9\text{-}O_2))}$$

where

E = Emission Factor, lb/10^3 gal
F = F factor specific to fuel type
O_2 = % oxygen in exhaust gas typical to equipment unit
C = Pollutant Concentration

<u>Unit: Used oil fired auxiliary burner (Unit No. 3)</u>

From AP-42, Table 1.11-1, PM emission factor = 64A lb/10^3 gal
Where, A is the ash content of the used oil determined to be 0.36% from the August 20, 2003 fuel analysis

From 40 CFR 60, Appendix A, Table 19-1, F=9,190 dscf/MMBtu

Converting emission factor assuming 150,000 Btu/gal.
PM emission factor = (64 lbx0.36/10^3 gal)/0.15 MMBtu/gal) = 0.154 lb/MMBtu

Solving for C, converting to grains for standard cubic foot (gr/scf) and assuming 3% excess oxygen,

C = E(20.9-O_2)/F(20.9)

C = 0.154 lb/MMBtu (20.9-3)/ 9,190 scf/MMBtu(20.9) = 1.44 x 10^{-5} lb/scf

C = 1.44 x 10^{-5} lb/scf x 7000 gr/lb = 0.10 gr/scf

Or, 0.10 gr/scf is double the 0.05 gr/scf standard.

DF-8 fuel oil will have grain loading of 0.01 gr/scf when using AP-42 Table 1.3-1 PM emission factor of 2 lb/10^3 gal and heating value of 126,815 MMBtu/gal. In order to meet grain loading requirements of 0.05 gr/scf, the used oil will need to be blended with distillate oil at a ratio of 1:X and solve for X as follows:

$$\frac{0.1 + 0.01X}{1 + X} = 0.05$$

$$X\,(0.05\text{-}0.01) = 0.1 - 0.05$$

$$X = 2$$

Therefore the used oil will have to be blended with distillate oil in the ratio of 1: 2

Sulfur Dioxide Demonstration

Compliance with Sulfur Dioxide Emissions Limit: Method 19 40 CFR 60 Appendix A

Goal: Determine what percent (%) sulfur in **fuel oil** will ensure compliance with 500 parts per million (ppm) limit found in 18 AAC 50.055(c).

Known:

Known:	C_d	500 ppm, uncorrected for oxygen, assumed to be on a dry basis
	F_d	9,190 dscf/MMBtu, F factor, 40 CFR 60 App. A, Method 19, (Oil)
	H_{FO}	0.019320 MMBtu/lb, heat content of No. 2 fuel oil (AP-42)
	H	0.139 MMBtu/gallon
	ρ	7.128 lb fuel/gallon
	V	385 dscf/lbmol, volume of ideal gas at standard conditions
	MW	64 lb SO_2/lbmol, molecular weight of SO_2
	%S	percent Sulfur in fuel by weight
	2	64 lb SO_2/32 lb S, stoichiometric equation ($S + O_2 \rightarrow SO_2$)

Assumption: Fuel oil fired exclusively.

Solution: Determine %S equivalent to C_d = 500 ppm

$$\%S = \frac{\left[Cd\,\frac{dscfSO_2}{dscf_{fluegas}}\right]\left[MW\,\frac{lbSO_2}{lbmol}\right]\left[Fd\,\frac{dscf_{fluegas}}{MMBtu}\right]\left[H\,\frac{MMBtu}{gallon}\right]}{\left[V\,\frac{dscfSO_2}{lbmol}\right]\left[2\,\frac{lbSO_2}{lbS}\right]\left[\rho\,\frac{lbfuel}{gallon}\right]}[100\%]$$

$$\%S = \frac{\left[\frac{500}{1{,}000{,}000}\right][64][9{,}190][0.139]}{[2][385][7.128]}[100\%]$$

$$\%S = 0.74\%$$

Answer: Compliance with a percent sulfur content less than 0.74% ensures compliance with respect to the 500 ppm emission limit found in 18 AAC 50.055(c).

EXHIBIT C

Capital Cost Summary for NOxTECH

	NOx		CO	
DIRECT COSTS (for both engines)	**Applicant**	***Revised***	**Applicant**	***Revised***
PURCHASED EQUIPMENT COSTS				
NOxTECH units (4x $285,000 each) (vendor quote)	1,140,000	*1,140,000*	1,140,000	*1,140,000*
Urea Storage Tank (vendor quote)	16,000	*16,000*	16,000	*16,000*
Cold Weather Insulating (vendor quote)	13,000	*13,000*	13,000	*13,000*
Instrumentation (10% of equipment costs)	116,900	*116,900*	116,900	*116,900*
Freight (5% of equipment costs)	58,450	*58,450*	58,450	*58,450*
Total Purchased equipment costs	1,344,350	*1,344,350*	1,344,350	*1,344,350*
DIRECT INSTALLATION COSTS				
Foundation (8% of total purchased equipment costs)	107,548	*107,548*	107,548	*107,548*
Erection (14% of total purchased equipment costs)	188,209	*188,209*	188,209	*188,209*
Electrical (4% of total purchased equipment costs)	53,774	*53,774*	53,774	*53,774*
Piping (2% of total purchased equipment costs)	26,887	*26,887*	26,887	*26,887*
Insulation (1% of total purchased equipment costs)	13,443	*13,443*	13,443	*13,443*
Painting (1% of total purchased equipment costs)	13,443	*13,443*	13,443	*13,443*
Total direct installation costs	403,305	*403,305*	403,305	*403,305*
Revised total direct installation costs LAF		***1,387,369***[a]		***1,387,369***[a]
TOTAL DIRECT CAPITAL COSTS	1,747,655	*2,731,719*	1,747,655	*2,731,719*
INDIRECT COSTS[b]				
Engineering (30% of total purchased equipment costs)	403,305	*403,305*	403,305	*403,305*
Construction management (10% of total purchased equipment costs)	134,435	*134,435*	134,435	*134,435*
Construction fee (20% of total purchased equipment costs)	268,870	*268,870*	268,870	*268,870*
Airfare ($2,000/person roundtrip x 17)	34,000	*34,000*	34,000	*34,000*
Start up (2% of total purchased equipment costs)	26,887	*26,887*	26,887	*26,887*
Performance test (assume $50,000)	50,000	*50,000*	50,000	*50,000*
TOTAL INDIRECT COSTS	917,497	*917,497*	917,497	*917,497*
TOTAL INSTALLED COST	2,665,152	*3,649,216*	2,665,152	*3,649,216*
CONTINGENCY (30% of total installed cost)	799,546	*547,382*[c]	799,546	*547,382*[c]
TOTAL CAPITAL INVESTMENT	3,464,698	***4,196,598***	3,464,698	***4,196,598***
CORRECTED TOTAL CAPITAL INVESTMENT	**13,336,868**[d]		**13,336,86**[d]	

Please see footnotes at the end of the annualized Cost Summary for NOxTECH

Annualized Cost Summary for NOxTECH

	NOx		CO	
DIRECT ANNUAL COSTS	**Applicant**	***Revised***	**Applicant**	***Revised***
OPERATION AND MAINTENANCE				
Maintenance labor (2% of total capital investment	266,737	*266,737*	266,737	*266,737*
Maintenance materials (20% of maintenance labor)	53,347	*53,347*	53,347	*53,347*
Total operations and maintenance	320,084	*320,084*	320,084	*320,084*
UTILITIES AND MATERIALS				
Additional fuel (35 gal/hr x 2 units x 8,760 hr/yr x $0.84/gal	515,088	*515,088*	515,088	*515,088*
Urea ($0.7/gal x 45 gph x 8,760 hours/yr x $2/gal, LAF, SSF)	2,124,385	*551,880*[e]	2,124,385	*551,880*[e]
Cost of shipment (40% of cost of utilities)		*426787*		*426787*
Total Utilities and materials	2,639,473	*1,493,755*	2,639,473	*1,493,755*
TOTAL DIRECT ANNUAL COSTS	2,959,557	*1,181,839*	2,959,557	*1,181,839*
INDIRECT ANNUAL COSTS				
Overhead (80% of total operation and maintenance)[f]	256,067		256,067	
Administrative charges (2% of total capital investment)	266,737	*83,932*	266,737	*83,932*
Insurance (1% of total capital investment)	133,369	*41,966*	133,369	*41,966*
Property tax (1% of total capital investment)	Exempt	*Exempt*	Exempt	*Exempt*
Capital recovery (24.4% of total capital investment: 5 yr at 7% int., based on site conditions	3,254,196	*778,679*[g]	3,254,196	*778,679*[g]
Capital recovery of forfeited expenditure (FY02 heat exchange replacement project)	70,574			
TOTAL INDIRECT ANNUAL COSTS	3,980,943	*904,577*	3,910,369	*904,577*
TOTAL ANNUALIZED COSTS	6,940,500	*2,990,953*	6,869,926	*2,990,953*
TOTAL UNCONTROLLED POLLUTANT EMISSIONS, ton (potential increase)	845	*845*	194	*194*
POLLUTANT REMOVAL EFFICIENCY, %	96	*96*	80	*80*
TOTAL POLLUTANT REMOVED, tons (potential increase)	811	*811*	155	*155*
2002 COST-EFFECTIVENESS, $/ton removed	**8,558**	***3,688***	**44,322**	***19,296***

[a] Direct installation costs corrected using Location Adjustment Factor (LAF) of 3.44. LAF reflects the average statistical difference in normal labor, material, and equipment costs for similar facilities built elsewhere (TM 5-800-4 Manual). The factor also makes allowances for weather, seismic, climatic, normal labor availability etc. The add on control is a module that will be transported and installed in Shemya and not a facility that will be built on site in proper sense. It may be appropriate to adjust the direct installation costs using the LAF but not the equipment cost. The site sensitivity factor (SSF) is an adjustment for special cases where the unique nature of both the site (extensive site limitations) and project (extreme construction effort), in relation to one another will cause a significant impact on the cost. In this case the location is unique but the project itself is not labor intensive. It is inappropriate to adjust the overall costs including the equipment cost with SSF and LAF. Therefore the SSF appear to be inapplicable. The costs of transporting labor have been accounted separately. Therefore the direct installation/overhead costs and not the equipment costs are adjusted by a LAF of 3.44.

[b] With the exception of the airfare for personnel to install and startup, the Department has no basis for percentages used to determine indirect costs. Performance test is usually included in startup and appears to be a

redundant cost. Direct and indirect costs have been accounted above. As such the contingency appears to be redundant as well.

[c] The Department is unable to concur with contingency equivalent to 30% of installed costs. The Department adopted a 15% contingency factor per EPA Air Pollution Control Cost Manual.

[d] Applicant has adjusted the total cost by LAF (3.44) and SSF (1.119) factors. The Department disagrees with the use of LAF and SSF on equipment costs.

[e] The Department disagrees with the use of the combined LAF and SSF factors for catalytic replacement for reasons discussed in item (d) above. Revised estimates are based on no credit for reuse of catalysts and 40% shipment cost for utilities.

[f] The Department has no basis for overhead of 80% of operation and maintenance. Overheads have been accounted for in Operation and Maintenance and Utilities. Therefore the Department removed the 80% contingency.

Capital Cost Summary for SCR/Oxidation Catalysts

	NOx		CO	
DIRECT COSTS (for both engines)	**Applicant**	***Revised***	**Applicant**	***Revised***
PURCHASED EQUIPMENT COSTS[a]				
Equipment cost (Instrumentation and control panels)	300,000	*300,000*	300,000	*300,000*
4,000 gallon fiberglass urea make down tank (1 unit)	30,500	*30,500*	30,500	*30,500*
4,000 gallon fiberglass urea tank (1 unit)	30,500	*30,500*	30,500	*30,500*
Urea feed system with superstack support structure and feeder (1 unit)	25,000	*25,000*	25,000	*25,000*
Urea liquid transfer pump (1 unit)	4,000	*4,000*	4,000	*4,000*
Urea feed pumps (2 units)	9,000	*9,000*	9,000	*9,000*
Urea ammonia injection system (2 units)	13,000	*13,000*	13,000	*13,000*
Additive feed system with tote support frame	12,000	*12,000*	12,000	*12,000*
2" stainless steel insulated piping from tanks to SCR (160 LF x $29.75 LF	4,760	*4,760*	4,760	*4,760*
Valves and gauges at tanks (1 lot)	10,000	*10,000*	10,000	*10,000*
Sampling platform and ports for stack testing (2 units)	40,000	*40,000*	40,000	*40,000*
Ductwork and dampers from SCR to gensets (2 units)	30,000	*30,000*	30,000	*30,000*
Continuous Emissions Monitoring Systems (USACE Estimate)[b]	213,333	*213,333*	213,333	*213,333*
Freight to Anchorage AK (Argillon Quote)[c]	8,500		8,500	
Freight from Anchorage to Eareckson AS - C130 ($60,000 RT x 2 trip)[c]	120,000		120,000	
Total equipment costs	850,593	*722,093*	850,593	*722,093*
DIRECT INSTALLATION COSTS				
Water Pre-treatment System (USACE Estimate)[b]	61,220	***61,220***	61,220	***61,220***
Foundation (8% of total purchased equipment costs)[d]	68,047	*57,767*	68,047	*57,767*
Erection (14% of total purchased equipment costs)[d]	119,083	*101,093*	119,083	*101,093*
Electrical (4% of total purchased equipment costs)[d]	34,024	*28,884*	34,024	*28,884*
Piping (2% of total purchased equipment costs)[d]	17,012	*14,442*	17,012	*14,442*
Insulation (1% of total purchased equipment costs)[d]	8,506	*7,221*	8,506	*7,221*
Painting (1% of total purchased equipment costs)[d]	8,506	*7,221*	8,506	*7,221*
Total direct installation costs	316,398	*277,848*	316,398	*277,848*
TOTAL DIRECT CAPITAL COSTS	1,166,991	*999,941*	1,166,991	*999,941*
INDIRECT COSTS				
Engineering and Supervision (20% of total equipment cost)[d]	170,119	*144,419*	170,119	*144,419*
Construction fee Multiple Contractors (10% of equipment costs)[d]	42,530	*36,105*	42,530	*36,105*
Construction fee Multiple Contractors (20% of equipment costs)[e]	85,059		85,059	
Startup (6 man days at 1500 per man day, HMS estimate)[a]	9,000	*9,000*	9,000	*9,000*
Performance test (assume $ 50,000)	50,0000	*50,000*	50,0000	*50,000*
Electrical Contract Overhead (29% of Electrical Installation costs)[f]	9,867			
Foundation Contract Overhead (29% Foundation Installation Costs)[f]	19,734			
Mechanical Overhead (31% of Piping, Insulation @ Painting Costs)[f]	10,547			
Prime Contractor Overhead (16.1% of Total Direct Installation Costs)[f]	50,940			
TOTAL INDIRECT COSTS	447,796	*458,789*	447,796	*458,789*
TOTAL INSTALLED COST	1,614,787	*1,239,464*	1,614,787	*1,239,464*
CONTINGENCY (30% of total installed cost)[e]	484,436	*371,839*	484,436	*371,839*
TOTAL CAPITAL INVESTMENT	2,099,222	***1,611,303***	2,099,222	***1,611,303***

a. Purchase equipment costs except CEMS and water treatment are brought in from HMS cost estimates of March 2001. HMS estimates are turn-key type (Pricing includes wage rates, materials, freight and equipment).
b. Cost of CEMS and water treatment are from Tri-Service Automated Cost Engineering System (TRACES). TRACES cost estimate are for the installation of SCR and CEMs for all 6 Cooper Bessemer engines. These estimates are scaled down to 2 CEMS units (640,000÷3)
c. Freight charges included in HMS estimates. Therefore previous vendor shipping cost to Anchorage and C-130 transportation costs irrelevant.
d. Although the HMS cost estimates are turn-key type, the Department is allowing this added costs to account for building structure for SCR
e. HMS cost estimates are turn-key type that includes contractor costs.
f. Indirect installation costs include overheads.
g. HMS estimates 20% for Architecture and Engineering and 10 % for Escalation; total 30% for contingency. Note this allowance is for total equipment cost per HMS cost estimates, but the Department is allowing a 30% of total installed costs to account for the remote location.

Annualized Cost Summary for SCR/Oxidation Catalysts

	NOx		CO	
DIRECT ANNUAL COSTS	**Applicant**	***Revised***	**Applicant**	***Revised***
OPERATION AND MAINTENANCE				
Operating labor (4 hr/day x $60/hrx365 day/yr, similar unit)	87,600	*87,600*	87,600	*87,600*
Supervision (15% of operating labor)	13,140	*13,140*	13,140	*13,140*
Maintenance labor ((16 hrs/quarter for NOx, 8 hrs/quarter for CO) x 4 quarters x $60/hr, vendor quote)	3,840	*3,840*	1,920	*1,920*
Maintenance materials (20% of maintenance labor)	768	*768*	384	384
Total operations and maintenance	105,348	*105,348*	103,044	*103,044*
UTILITIES AND MATERIALS				
Reagent Costs (8 gal/hour/unit x 2 units x 8,760 hours/yr x $2/gal)	280,320	*280,320*		
Catalytic replacement and disposal ($40,000/unit for NOx and $30,000 for CO)x 2 units + $1,310 disposal for NOx and - $1,600, over 3 yr at 7% int)	30,983	*30,983*	23,362	*23,362*
Cost of shipment (40% of cost of utilities)	124,521	*124,521*	9,345	*9,345*
Total Utilities and materials	435,825	*435,825*	32,707	*32,707*
TOTAL DIRECT ANNUAL COSTS	541,172	*541,167*	135,751	*135,751*
INDIRECT ANNUAL COSTS				
Administrative charges (2% of total capital investment)	41,984	*39,497*	41,984	*39,497*
Capital recovery (18.55% of total capital investment: 7 yr at 7% int., based on site conditions	389,517	*298,982*	389,517	*298,982*
Insurance (1% of total capital investment)	20,992	*16,328*	20,992	*16,328*
TOTAL INDIRECT ANNUAL COSTS	452,494	*347,321*	452,494	*347,321*
TOTAL ANNUALIZED COSTS	**993,667**	***888,494***	**588,245**	***483,073***
TOTAL UNCONTROLLED POLLUTANT EMISSIONS, ton (potential increase)	845		194	*194*
POLLUTANT REMOVAL EFFICIENCY, %	90	*90*	80	*80*
TOTAL POLLUTANT REMOVED, tons (potential increase)	761	*761*	155	*155*
2002 COST-EFFECTIVENESS, $/ton removed	**1,307**	***1,168***	**3,795**	***3,117***

EXHIBIT D
Department Review Memorandum Regarding the Ambient Analysis

MEMORANDUM

State of Alaska
Department of Environmental Conservation
Division of Air and Water Quality

TO: File

THRU: Jim Baumgartner
Construction Permits Supervisor
Air Permits Program

FROM: Alan Schuler, P.E. AES
Environmental Engineer
Air Permits Program

DATE: July 24, 2003

FILE NO.: X176 – Modeling

PHONE: 465-5100
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SUBJECT: Review of the Eareckson Ambient Assessment

As required under 18 AAC 50.315(b)(1)(A), this memorandum summarizes the Department's findings regarding the ambient assessment submitted by the 611th Air Support Group (611 ASG) for Eareckson Air Station (EAS). The 611 ASG provided the assessment as part of their January 2003 permit application for an air quality control construction permit. The application pertains to past modifications and proposed modifications that are subject to the State's Prevention of Significant Deterioration (PSD) program. The assessment includes an analysis of the potential pre-construction monitoring obligations, impacts on the ambient air quality standards and increments, and impacts on Air Quality Related Values (AQRVs).

The 611 ASG's analysis adequately shows that operating their emission units within the requested constraints will not cause or contribute to a violation of the Alaska Ambient Air Quality Standards (AAAQS) provided in 18 AAC 50.010, or the maximum allowable increases (increments) listed in 18 AAC 50.020. The 611 ASG also demonstrated that pre-construction monitoring is not required and that there are no adverse AQRV impacts. Through this memorandum, the Department is summarizing the key components, comments and results of the Ambient Data Assessment, Ambient Impact Analysis, and AQRV analysis.

BACKGROUND

EAS is located on and occupies all of Shemya Island, which is located near the most western part of the Aleutian Island chain. The area is unclassified in regards to compliance with the AAAQS. For purposes of demonstrating compliance with the increments, Shemya Island is classified as a "Class II" area. The nearest "Class I" areas are the Simeonof National Wildlife Refuge and the Bering Sea National Wildlife Refuge, which are both located over 1,000 miles (1,600 km) away.

EAS operates under the control of the U.S. Air Force (USAF), under the major command of Pacific Air Forces (PACAF). The stationary source is currently classified under 18 AAC 50.300(c) as a PSD Major Stationary Source for oxides of nitrogen (NOx), sulfur dioxide (SO_2) and carbon monoxide (CO).

The 611 ASG submitted an air quality control construction permit application on January 27, 2003 to address a 1988 major modification and proposed modifications through 2007. The 1988 modification should have triggered PSD review under 18 AAC 50.300(h)(3) for NOx and CO. The proposed modifications trigger PSD review for NOx, and SO_2. PSD applications must include an ambient analysis for those pollutants per 18 AAC 50.310(d). The modifications are also classified for PM-10 under 18 AAC 50.300(h)(2). Therefore, the 611 ASG was required under 18 AAC 50.310(n)(2) to model PM-10. The Department also asked the 611 ASG to model the CO impacts for the post-2002 PSD project under the discretionary provision contained in 18 AAC 50.310(c)(5).

The 611 ASG submitted a modeling protocol on May 24, 2002. The Department provided comments on August 2, 2002. The 611 ASG then provided a new, *draft* modeling protocol in September 2002. They also discussed the proposed modeling analysis with the Department during a September 5, 2002 meeting. The Department verbally agreed with the revised modeling approach during the September 5th meeting.

The Department conducted a cursory review of the January 2003 analysis and raised several questions in a March 6, 2003 letter to the 611 ASG. In addressing these questions, the 611 ASG found some mistakes and submitted a revised ambient assessment as part of their June 6, 2003 "Addendum 2." In response to additional questions and inconsistencies, the 611 ASG submitted an additional revision via electronic mail (e-mail) on July 22, 2003. The findings provided in this memorandum are based on the revised submittal, except as noted otherwise.

The 611 ASG developed the identification number ("Model ID") for each emission unit in the modeling files separately from the "Source IDs" developed for the proposed permit. Therefore, the Department used a source description, as well as the Model ID, when discussing specific emission units in this memorandum.

Battelle conducted the pre-construction monitoring analysis, the ambient impact analysis, and AQRV analysis on behalf of the 611 ASG.

AMBIENT AIR POLLUTANT DATA

18 AAC 50.310(d)(1) requires PSD applicants to submit ambient monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the predicted ambient impact of the proposal is less than the monitoring threshold provided in 18 AAC 50.310(e). The requirement only pertains to PSD pollutants. The data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the estimated ambient impact from the proposed project. The 611 ASG's approach for meeting both data needs is discussed below.

Pre-Construction Monitoring

The 611 ASG used computer analysis (modeling) to compare the predicted impacts from both PSD projects to the monitoring thresholds. The details regarding the modeling analysis are described in the "Ambient Impact Analysis" section of this memorandum.

1988 Project Impact Assessment

The 611 ASG modeled the NO_2 and CO impacts for the 1988 PSD project and compared the maximum impacts to the monitoring thresholds. The maximum impacts, along with the monitoring thresholds, are presented in Table 1.

Post-2002 Project Impact Assessment

The 611 ASG is planning to install, replace, and remove a number of emission units over the next four years. They summarized the specific changes in Section 2.3.3 and Table 2-3 of their application. For purposes of modeling the post-2002 project impacts, the 611 ASG assumed all of these changes occur simultaneously. The 611 ASG modeled the NO_2 and SO_2 post-2002 project impacts, as required under 18 AAC 50.310(d)(1).

The Department accepts the simultaneous assumption for modeling new and replaced units. The NO_2 and SO_2 post-2002 project impact results are also presented below in Table 1 below.

Table 1 – Pre-Construction Monitoring Assessment

Air Pollutant	Avg. Period	1988 PSD Project Impact (μg/m^3)	Post-2002 PSD Project Impact (μg/m^3)	Monitoring Threshold (μg/m^3)
NO_2	Annual	11	5	14
SO_2	24-hour	not applicable	12	13
CO	8-hr	62	Not applicable	575

Project Impact Results

The maximum impacts estimated for both PSD projects are less than the monitoring thresholds. Therefore, pre-construction monitoring would not have been required in 1988, and is not required for the post-2002 proposal.

Background Concentrations

In addition to the pre-construction monitoring requirements for PSD pollutants, ambient "background" data may also be needed to supplement the ambient impact analysis. The background concentration represents impacts from sources not included in the modeling analysis. Typical examples include natural, area-wide, and long-range transport sources. The background concentration must be evaluated on a case-by-case basis for each ambient impact analysis. Once the background concentration is determined, it is added to the modeled concentration to estimate the total ambient concentration. Hence, background concentrations are typically needed for all air pollutants included in an AAAQS compliance demonstration, regardless of whether or not PSD pre-construction monitoring is required.

The USAF has never collected ambient data at EAS. Therefore, the 611 ASG used the maximum concentrations measured at other remote, maritime locations to represent the background concentrations at EAS. The background NO_2 data were collected from July 1995 through May 1996 in Pyramid Valley on Unalaska Island. The background SO_2, PM-10 and CO data were collected from July 1993 through September 1994 as part of the Sunfish Development project in Beluga. The maximum concentrations measured during these monitoring efforts are provided in the results section of this memorandum. The Department considers these data to be adequately representative of the expected background concentrations at EAS.

AMBIENT IMPACT ANALYSIS – APPROACH

The 611 ASG used computer analysis (modeling) to predict the ambient NO_2, SO_2, PM-10 and CO air quality impacts from the emission units listed in the permit application. They used the U.S. Environmental Protection Agency's (EPA) *SCREEN3* and *Industrial Source Complex Short-Term 3* (ISCST3) models for the ambient analysis. They used SCREEN3 to conduct a load analysis of the larger emission units and ISCST3 for the ambient assessment. The 611 ASG used the current version of both models. Both models are appropriate for this analysis. Per the Department's request, the 611 ASG conducted a full impact analysis for each pollutant.

The 611's application is notably different from the typical project reviewed by the Department. The application addresses both past and future PSD projects at the site, along with numerous smaller changes to the emissions inventory. This created a large number of emission activities that needed to be tracked and addressed to adequately portray the ambient impacts.

The 611 ASG used a very unique approach in modeling the EAS emission units. They included a Model ID for each unit existing in 1980 (referred by the 611 ASG as a "baseline" unit), as well as each installation, modification and removal that has occurred subsequent to 1980.[1] They also included a "place holder" Model ID (an emission unit with zero emissions) in the "baseline" inventory for units installed subsequent to 1980. This resulted in modeling files containing a total of 302 "emission sources."

This level of detailed emission unit tracking is needed for permit applicability determinations, but it can be "overkill" in carrying it through to an ambient demonstration. For example, EAS installed two 2.01 MMBtu/hr boilers in Building 597 in 1991. They removed them in 1994, but plan to reinstall them in 2005. The 611 ASG included a unique Model ID and emission characteristic (credit or debit, as applicable) for all three actions in the post-2002 increment analysis and AAAQS analysis. However, all of these actions occurred or will occur subsequent

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[1] The term "baseline" can have a variety of meanings in air quality permitting. The 611 ASG used the term as the starting point for tracking the stationary source modifications, to determine when the modifications would have required PSD review. The starting point for tracking these modifications is listed in 18 AAC 50.300(h)(3)(A) as August 7, 1980. In modeling applications, "baseline" typically refers to the emission unit inventory and actual air quality concentrations in existence during the "applicable baseline date" established for the given Air Quality Control Region. The baseline dates for each Air Quality Control Region are listed in Table 2 of 18 AAC 50.020(a). EAS is in the South Central Alaska Intrastate Air Quality Control Region. Therefore, the SO_2 and PM-10 baseline dates are October 26, 1979 and the NO_2 baseline date is February 8, 1988. In this context, the PM-10 and SO_2 "baseline concentrations" also include the *allowable* emissions from major stationary sources for which construction commenced before January 6, 1975, but was not in operation by the baseline date, while otherwise excluding the *actual* emissions from a major stationary source for which construction commenced on or after January 6, 1975 – per 18 AAC 50.020(e)(1). The 611 ASG stated the 1980 "baseline" inventory is identical to the emission unit inventory in existence during the 1979 SO_2 and PM-10 baseline date. Therefore, the 611 ASG used the 1980 baseline inventory to estimate the SO_2 and PM-10 PSD baseline concentrations. The Department accepts this assumption and notes that there is no evidence to show that the 1980 inventory substantially differs from the either the 1979 or 1975 inventories.

to all of the PSD baseline dates. Therefore, in this example, the 611 ASG only needed to include the 2005 reinstallation in the increment and AAAQS ambient demonstrations.

The detailed approach used by the 611 ASG is not wrong. However, it makes the modeling files extremely large, which slows review time. The use of large inventories also increases the potential for source confusion, data entry errors and inconsistencies. The Department found several cases of inconsistent nomenclature and unit confusion in Table 5-24 of the original application and in the modeling files. Three examples are listed below.

- The 611 ASG typically revised a baseline Model ID with a decimal to designate changes not related to the PSD actions. For example, the 611 ASG would use a Model ID of "89" (or some other number) to designate the 1980 emission characteristics of a particular emissions unit, and "89.1" to designate a latter emission characteristic (not associated with one of the two PSD permit actions) for that same unit. However, they did not use this convention in regards to Model ID "55" and Model ID "55.5". In this case, Model ID 55 refers to a 260 kW generator while Model ID 55.5 refers to a 0.255 MMBtu/hr boiler.

- Model ID "85" typically referred to a 2.01 MMBtu/hr boiler in building 597, but was also used to refer to a 2.5 MMBtu/hr boiler in Building 601.

- Model ID "18" typically referred to a 60 kW generator in building 221, but was also used along with Model ID "19" to refer to a 100 kW replacement unit

The 611 ASG also used a different nomenclature series for the PM-10 analysis from what they used in the NO_2, SO_2 and CO analyses. ***While the 611 ASG did note this change in convention, it would have been better if they used a consistent nomenclature to identify their future emission units.***

The 611 ASG also used actual emissions, rather than allowable emissions, to model the *projected* annual average impacts from the *existing* EAS emission units. This approach is inconsistent with past Department practice of using allowable emissions to estimate the future annual average impacts from existing emission units. The use of future actual emissions in an increment analysis can also lead to an excessive increment credit, if the current actual emissions are larger than the baseline actual emissions. For example, if the actual emissions for an emissions unit removed in 1994 are larger than the actual emissions during the baseline year, then the modeled "credit" would be larger than the baseline "impact."

According to Table 9-2 of EPA's *Guideline on Air Quality Models*, actual emissions can be used "*if* the emissions from the existing facility will not be affected by the modification" (emphasis added). The clause implies that actual emissions may be used only if there will not be any change in operation for the existing emission units. However, it is very clear from the remaining text that allowable emissions should be used if there will, or could be, increased operation of the existing emission units. For this reason, the Department's standard practice is for applicants to model the future allowable emissions from their existing emission units. Using this approach to demonstrate compliance with the State's air quality standards and increments ensures that the applicant can have full operational flexibility, without creating an adverse air quality impact. In regards to EAS, the use of allowable emissions is especially warranted considering the potential for increased operations associated with the likely growth of National Security activities.

The 611 ASG addressed the Department's concern by presenting two AAAQS demonstrations as a surrogate to revising the entire analysis using allowable emissions for every emission unit. The first demonstration used the as-modeled results, which is based on actual emissions for the baseline emission units and allowable emissions for the "post-baseline" emission units. The second demonstration is based on an adjustment to the baseline impact. The 611 ASG multiplied the maximum impact from the "baseline" emission units by the ratio of total allowable to total actual emissions (2.86). They then added this adjusted value to the maximum-modeled impact from the post-baseline activities. The Department considers this approach as an adequate surrogate to modeling the true allowable emissions from each emission unit. The results from both approaches are provided in this memorandum.

Meteorological Data

ISCST3 requires hourly meteorological data to estimate plume dispersion. The 611 ASG used the same five-year (1988-1992) meteorological data set as used by the National Missile Defense Joint Program Office (NMD-JPO) in support of the once-proposed Shemya X-Band Radar facility. The NMD-JPO used surface and upper air meteorological data collected by the USAF at EAS and processed the data using EPA's *PCRAMMET* program. However, they also noted that the Holzworth mixing height algorithm in PCRAMMET is designed for a continental setting and therefore, could provide incorrect mixing heights when processing data from a small north pacific island, such as Shemya. The NMD-JPO discussed the issue with the Department's meteorologist (Gerry Guay). Based on these conversations, the Department agreed that NMD-JPO could reset the minimum mixing height to 140 meters during non-stable hours. The condition of concern occurred less than 100 hours per year.

The use of the NMD-JPO data set is appropriate for this ambient assessment. The use of five years of meteorological data is also appropriate.

EPA allows applicants to compare the high second-high (h2h) modeled concentration to the short-term air quality standards and increments if at least one year of temporally representative site-specific, or five years of representative off-site data, are used. When these criteria are not met, then the high first-high (h1h) estimate is to be used. Applicants must also always compare the h1h modeled concentration to the significant impact levels (SILs) and the pre-construction monitoring thresholds. The Department allowed the 611 ASG to compare the h2h modeled concentration to the standards and increments in their application since the data set meets the length of record requirement.

Receptor Grid

Access to EAS is restricted to mission-related personnel. There are no locations on the island that are accessible to the general public. Therefore, the 611 ASG used the coast-line as their ambient air boundary and developed a receptor grid from the coast-line to 4-kilometers off-shore. The 611 ASG also placed on-shore receptors at the off-duty housing areas (Buildings 597, 598, 599, 600), as well as Building 618 (communication facility), and the future Defense Satellite Communications Systems (DSCS) facility. The DSCS facility will be operated by the Ballistic

Missile Defense Organization (BMDO) and Strategic Missile Defense Command (SMDC) as part of the Ground-based Midcourse Defense (GMD) test-bed deployment, scheduled for fiscal year 2004 (FY04). A stationary source located within a stationary source that is owned and operated by a different entity is considered ambient air. Therefore, the 611 ASG's placement of a receptor at the DSCS facility is appropriate. Figures 5-2 and 5-3 of the application show the resulting receptor grid layout.
The 611 ASG included flagpole receptors at the off-duty housing areas and Building 618. The use of flagpole receptors for housing areas is standard practice. However, the following items should be noted:

1. The increment standards do not apply at flagpole receptors, and
2. The Department typically requests applicants to collocate a ground-level receptor with each flagpole receptor.

The 611 ASG collocated a second, shorter flagpole receptor with each primary flagpole receptor, instead of the typical practice of collocating a ground-level receptor with the primary flagpole receptor. The 611 ASG then included the flagpole sets in the increment analysis. While this approach is non-standard, the Department will accept it since the use of flagpole receptors provides for a more conservative increment analysis.

Part-load Analysis
The maximum ambient concentrations do not always occur during the full-load conditions that typically produce the largest emissions. The relatively poor dispersion that occurs with cooler exhaust temperatures and slower part-load exit velocities may produce the maximum ambient impacts. Therefore, EPA recommends that part-load conditions be analyzed as well as full-load conditions. The 611 ASG used SCREEN3 to model the part-load emissions from one of the 3 MW Cooper-Bessemer main power plant engines. The SCREEN3 analysis showed that the worst-case impacts occur during full-load conditions. Therefore, the 611 ASG used the full-load conditions when modeling the Cooper-Bessemer engines (Model IDs 1-6) with ISCST3.

Emission Unit Locations, Emission Rates and Stack Parameters
The assumed emission unit location, emission rate and stack parameters (for a given load) can play significant roles in an ambient demonstration. Therefore, the Department reviewed these parameters to ensure they are appropriate.

The Department found several minor errors and inconsistencies associated with the emission rates and stack parameters. Examples include:

- Use of the wrong EPA NOx emission factor in estimating the emissions for the 160 hp Firewater Pumps proposed for Bldg. 3049 (Model ID 105 & 106). The 611 ASG used the emission factor for 600 hp and larger engines instead of the emission factor for engines rated at less than 600 hp. The correct NOx emission rate for these units should be 0.036 grams per second (g/s) instead of 0.028 g/s. The Department used the corrected NOx emission rate in a revised modeling run of the pre-construction monitoring analysis. The revised analysis provided the same maximum impact as modeled by the 611 ASG.

- Use of different stack parameters when modeling identical, collocated Mitsubishi emergency generators. For example, the two 275 kW Mitsubishi emergency backup generators that were located in Building 4014 (Model ID 48 and 49) have inconsistent stack temperatures and stack diameters. Unit 48 was modeled with 450 K stack temperature while Unit 49 was modeled with a 477 K stack temperature. Unit 48 was characterized with a 41.5-meter equivalent diameter (adjusted for a 0.001 m/s vertical exit velocity) while Unit 49 was characterized with a 42.8-meter equivalent diameter. The Department found similar inconsistencies for the 350 kW Mitsubishi generators (Model ID 46 and 47). These variations in stack parameters are curious but did not warrant a revised analysis.

- Emission credits that are greater than the initial emissions. For example, the 611 ASG used a 0.0006 g/s NO_2 emission rate for a 60 kW generator in Building 221 (Model ID 18) but modeled a 0.0012 g/s credit when the unit was removed. In the cases noticed by the Department, the errors had inconsequential impacts on the modeling assessment.

- Use of a positive NO_2 emission rate instead of a negative NO_2 emission rate to model the credit available from removing two 2.65 MMBtu/hr boilers (Model ID B98 and B99) in the pre-construction monitoring analysis. This made for a more conservative analysis, so is acceptable.

The presence of horizontal stacks or stacks with rain caps requires special handling in an ISCST3 analysis. EPA recommends that the plumes be characterized with an artificially small exit velocity (0.001 m/s) and an "equivalent diameter" to conserve the volume flow rate. The 611 ASG used EPA's recommended approach to characterize the EAS emission units with horizontal stacks or rain caps.

Ambient NO_2 Modeling
The modeling of ambient NO_2 concentrations can sometimes be refined through the use of ambient air data or assumptions. However, the 611 ASG took the most conservative approach of assuming full NO to NO_2 conversion.

Ambient SO_2 Modeling
SO_2 emissions are directly related to the amount of sulfur in the fuel. The USAF uses distillate fuels at EAS to operate their combustion sources. The USAF is currently using and plans to continue using DS-8. Prior to 1995, the USAF used DF-2.

According to the 611 ASG, the maximum fuel sulfur content of DS-8 is 0.30 percent, by weight. The 611 ASG essentially used this same fuel sulfur level (0.30%) to estimate the current and proposed SO_2 impacts in the modeling analysis. They made one unique minor modification though regarding their SO_2 emissions/impacts. The 611 ASG assumed that three percent of the fuel-bound sulfur is not converted to SO_2. This approach is inconsistent with the standard practice of assuming full conversion of fuel-bound sulfur to SO_2. However, since none of the modeled SO_2 impacts are within three percent of the AAAQS or increments, the potential ramifications of this unique method is moot.

The 611 ASG was not able to find fuel sulfur data from the 1979 SO_2 baseline year. However, they found a 1991 fuel sulfur analysis of a DF-2 delivery to EAS which indicated that the fuel sulfur content was 0.15 percent, by weight. Therefore, the 611 ASG assumed the fuel sulfur content during the baseline year was also 0.15 percent, by weight. The Department concurs with this assumption.

Downwash

Downwash refers to conditions where the plume pattern is influenced by nearby structures. Downwash can occur when a stack height is less than a height derived by a procedure called "Good Engineering Practice" (GEP), as defined in 18 AAC 50.910(43). The modeling of downwash-related impacts requires the inclusion of dimensions from nearby buildings. EPA has established specific algorithms for determining which buildings must be included and for determining the profile dimensions that would be "seen" by a given stack. They have also incorporated these algorithms in a separate computer program called the "Building Profile Input Program" (BPIP).

The 611 ASG used BPIP (version 95086) to determine the building profiles needed by ISCST3. This is the current version of BPIP and is appropriate for this analysis. The EPA released version of BPIP will only process a maximum of eight buildings and fourteen stacks, well below the total number of buildings and stacks at EAS. The 611 ASG made ten BPIP runs for the emission units located near the power plant and off-duty housing areas, and then compiled the results for ISCST3. The 611 ASG did not apply downwash for many of the smaller emission units located at the more distant areas of the base. This approach is reasonable.

Off-site Impacts

In a full impact assessment, the modeled impacts from relatively large off-site emission units located within 50 km of the applicant's significant impact area (SIA) are added to the modeled impacts from the applicant's stationary source. The 611 ASG included several small "off-site" emission units that will be installed on Shemya as part of the GMD test-bed deployment in FY04. The 611 ASG did not include any off-island emission units in the modeling analysis. The Department agrees that Shemya's extremely remote location precludes the need to specifically include any off-island emission units in the modeling analysis.

AMBIENT IMPACT ANALYSIS - RESULTS AND DISCUSSION

The maximum modeled NO_2, SO_2, PM-10 and CO AAAQS impacts are shown in Table 2. The adjusted impacts, as discussed earlier in this memorandum, are provided in Table 3. The background concentrations, total impacts and AAAQS are also provided in both tables. All of the total impacts are less than the applicable AAAQS. Therefore, the 611 ASG demonstrated compliance with the AAAQS.

Table 2 – Maximum AAAQS Impacts
(Using actual emissions for the existing emission units)

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Bkgd Conc (µg/m³)	TOTAL IMPACT: Max conc plus bkgd (µg/m³)	Ambient Standard (µg/m³)
NO_2	Annual	33	4	**37**	100
PM-10	24-hour	31	33	**64**	150
	Annual	1.2	6.5	**8**	50
SO_2	3-hr	215	13	**228**	1300
	24-hr	76	5.2	**81**	365
	Annual	9	2.6	**12**	80
CO	1-hr	2,920	3,100	**6020**	40,000
	8-hr	1,004	1,500	**2,504**	10,000

Table 3 – Adjusted Maximum AAAQS Impacts

Air Pollutant	Avg. Period	Maximum Modeled Impact (µg/m³)			Bkgd Conc (µg/m³)	TOTAL IMPACT (µg/m³)	Ambient Standard (µg/m³)
		"Baseline" Units	Adjusted Baseline	Post-2002 Units			
NO_2	Annual	16.3	46.6	17.0	4	**68**	100
PM-10	24-hour	20.2	57.8	28.8	33	**120**	150
	Annual	0.2	0.6	1.1	6.5	**8**	50
SO_2	3-hr	29.1	83.2	215	13	**311**	1300
	24-hr	16.2	46.3	76.0	5.2	**128**	365
	Annual	0.2	0.6	8.8	2.6	**12**	80
CO	1-hr	933	2,668	2,208	3,100	**7,976**	40,000
	8-hr	328	938	759	1,500	**3,197**	10,000

The maximum increment impacts for the 1988 PSD project are provided in Table 4. The maximum increment impacts for the post-2002 PSD project are provided in Table 5. The Class II increment standards are provided in both tables. All of the maximum impacts are less than the applicable Class II standard. Therefore, the 611 ASG has demonstrated compliance with the Class II increment standards.

Table 4 – 1988 PSD Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Class II Increment Standard (µg/m³)
NO_2	Annual	**11**	25

Table 5 – Post-2002 PSD Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Class II Increment Standard (µg/m³)
NO_2	Annual	**17**	25
PM-10	24-hour	**29**	30
	Annual	**1.1**	17
SO_2	3-hr	**215**	512
	24-hr	**76**	91
	Annual	**9**	20

It is important to note that since ambient concentrations vary with distance from each emission unit, the maximum values shown represent the highest value that may occur somewhere in the local airshed. They do *not* represent the highest concentration that could occur at *all* locations in the area.

ANALYSIS OF AIR QUALITY RELATED VALUES

As required under 18 AAC 50.310(d)(4), the 611 ASG submitted an analysis of the potential impact from EAS on the air quality related values (AQRV) for visibility, soil, vegetation, noise and odor. The AQRV analysis is only required for the project's PSD pollutants. Their assessment and the Department's findings are provided below.

Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility (visual range, contrast, or coloration) from that which would have existed under natural conditions (40 CFR 51.301(x)). Visibility impacts can be in the form of visible plumes ("plume blight") or in a general, area-wide reduction in visibility ("regional haze").

The nearest Class I areas are over 1600 km away. Therefore, a Class I visibility assessment was not required. However, the Department asked the 611 ASG to conduct a visibility analysis for an observer 50 km away (the maximum assessment distance for EPA's VISCREEN model). The 611 ASG conducted the VISCREEN analysis using two different background visual ranges for this weather-impaired location: a best-case scenario of 34 km and a worst-case (fog-impaired) scenario of 0.1 km. Using these values, the 611 ASG adequately demonstrated that there would not be visibility impacts at a location 50 km from EAS.

Soil and Vegetation Impacts

The 611 ASG compared the AAAQS to the sensitive vegetation thresholds listed in EPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals.* They noted that only the 3-hour SO_2 and annual average SO_2 thresholds are more stringent than the AAAQS. However, the modeled SO_2 impacts are well below the 3-hr threshold of 786

$\mu g/m^3$ and the annual average threshold of 18 $\mu g/m^3$. Therefore, the 611 ASG does not expect the EAS emission units to cause adverse vegetation impacts.

The Department asked the 611 ASG to specifically address the potential for impacting the endangered Aleutian shield fern. The 611 ASG contacted the U.S. Fish and Wildlife service and found that there is no evidence that the Aleutian shield fern occurs on Shemya Island. The Aleutian shield fern is found in mountainous habitat at elevations greater than 1,000 feet. This is well above the highest point on Shemya Island. The Department accepts the 611 ASG's assessment.

Noise and Odor Impacts
The 611 ASG does not expect noise and odor to be a concern due to the remote location and lack of nearby residential areas. The Department concurs with their finding.

CONCLUSION
The Department reviewed the 611 ASG's modeling analysis for EAS and concluded the following:

1. The NO_2, SO_2, PM-10 and CO emissions associated with operating the stationary source within the requested operating limits will not cause or contribute to a violation of the ambient air quality standards provided in 18 AAC 50.010, or the maximum allowable increases (increments) provided in 18 AAC 50.020.
2. The project should not lead to adverse visibility, soil, vegetation, noise, or odor impacts.
3. The 611 ASG's modeling analysis, as revised by the Department, fully complies with the showing requirements of 18 AAC 50.315(e)(2).
4. The 611 ASG conducted their modeling analysis in a manner consistent with EPA's *Guideline on Air Quality Models*.

The Department has developed conditions in the air quality control construction permit to ensure compliance with the ambient air quality standards and increments. These conditions are summarized below:

1. Limit the maximum sulfur content of the fuel to 0.30 percent by weight;
2. Limit the annual operation to the hours listed in Tables 2-5 and 2-6 of the application.

AES/cmd

Attachment C:
Emergency Engine Operating Data 2020-2022

Diesel Eng* Units 13-17, 27, 30, 32-36, 39-42, 50a, 51a Monthly Hours of Operation
Facility: Eareckson Air Station
AQ0307MSS04, Cond. 12
Reported in accordance with AQ0307TVP03, Rev. 2

	Unit ID: 13 Bldg. 3057 Detriot Firewater Pump #2 Limit: 1,000 hrs			Unit ID: 14 Bldg. 3057 Detriot Firewater Pump #1 Limit: 1,000 hrs			Unit ID: 15 Bldg. 4011 Clarke Fire Water Pump Limit: 500 hrs			Unit ID: 16 Bldg. 3052 Clarke Fire Water Pump #1 Limit: 500 hrs			Unit ID: 17 Bldg. 3052 Clarke Fire Water Pump #2 Limit: 500 hrs		
	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum
January	2	4.3	30.32	0	0	0	0.1	0.1	1.2	2	2	79.4	2	2.5	85.5
February	2.2	2	30.12	0	0	0	0.1	0.1	1.2	2	2	79.4	2	2	85.5
March	2	3	31.12	0	0	0	0.1	0.1	1.2	2.1	3	80.3	4.2	3	84.3
April	1.46	3	32.66	0	0	0	0.1	0.1	1.2	2.6	3	80.7	3.2	2	83.1
May	2	5.3	35.96	0	0	0	0.1	0.1	1.2	2	4.5	83.2	2	2.5	83.6
June	2.56	2	35.4	0	0	0	0.1	0.1	1.2	2.5	2.1	82.8	3.1	2	82.5
July	3.8	3.75	35.35	0	0	0	0.1	0.1	1.2	55.7	2	29.1	57.3	5	30.2
August	2.5	2.53	35.38	0	0	0	0.1	0.1	1.2	2	2.2	29.3	2.1	3	31.1
September	2	2	35.38	0	0	0	0.1	0.1	1.2	2	2.1	29.4	2.6	10.5	39
October	2.5	1.51	34.39	0	0	0	0.1	0.1	1.2	2	4.6	32	2	13.3	50.3
November	2.5	3.2	35.09	0	0	0	0.1	0.1	1.2	2.5	2	31.5	2.5	2	49.8
December	2.5	1.6	34.19	0	0	0	0.1	0.1	1.2	2	2	31.5	2	2	49.8

	Unit ID: 27 Bldg. 76-558 Mitsubishi EB Generator Limit: 500 hrs			Unit ID: 30a Bldg. 3049 Caterpillar EB Generator Limit: 300 hrs			Unit ID: 32 Bldg. 4014 Mistsubishi EB Generator Limit: 300 hrs			Unit ID: 33 Bldg. 4014 Mistsubishi EB Generator Limit: 300 hrs			Unit ID: 34 Bldg. 600 Caterpillar EB Generator Limit: 300 hrs		
January	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum
February	1.1	1.5	14.3	1	1	15	1	0.8	11.8	1	1	13.2	1	0	14
March	2.6	1	12.7	1	2	16	1	1.3	12.1	1	1	13.2	1	1	14
April	1.4	1	12.3	1	1	16	1	0	11.1	2	0	11.2	2	1	13
May	1	1.1	12.4	1	1	16	2	1	10.1	1	1	11.2	1	1	13
June	1	1.4	12.8	2	1	15	1	1	10.1	1	5	15.2	1	2	14
July	1	1	12.8	2	1	14	1	0	9.1	1	0	14.2	1	2	15
August	0.5	1.8	14.1	1	2	15	1	1	9.1	2	1	13.2	1	2	16
September	1.2	1.2	14.1	2	2	15	1	0	8.1	1.2	2	14	1	2	17
October	1	0	13.1	1	1	15	2	0	6.1	2	2	14	1	0	16
November	1	1.4	13.5	1	1	15	1	0	5.1	1	1	14	2	2	16
December	1	1	13.5	1	1	15	0	0	5.1	0	0	14	1	1	16
	1.1	1.4	13.8	1	1	15	0	0	5.1	0	2	16	2	1	15

	Unit ID: 35 Bldg. 609 Cummins EB Generator Limit: 500 hrs			Unit ID: 36 Bldg. 754 Caterpillar EB Generator Limit: 300 hrs			Unit ID: 40 Bldg. 628 Caterpillar EB Generator Limit: 300 hrs			Unit ID: 41 Bldg. 718 Cummins EB Generator Limit: 500 hrs			Unit ID: 42 Bldg. 775 Cummins EB Generator Limit: 500 hrs		
	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum	2020	2021	Rolling Sum
January	1	1.5	15	1.3	1.5	13.8	1	1	14	1	1	12.4	0	1.5	12.8
February	1	1	15	1	0.3	13.1	2	2	14	1.1	0.8	12.1	2.3	0.5	11
March	1	1	15	1.7	1.2	12.6	1	1	14	1.4	1.1	11.8	1.5	1.3	10.8
April	1	1	15	1.1	1	12.5	1	1	14	1	1.1	11.9	1.5	1	10.3
May	1	1	15	1.1	2.4	13.8	1	1	14	1.2	1.2	11.9	1.4	1.1	10
June	1.4	1.1	14.7	1.4	0.9	13.3	2	1	13	1	1.2	12.1	1.4	1.6	10.2
July	1	5	18.7	0.4	1.1	14	1	5	17	0.4	2.2	13.9	0	2	12.2
August	1.5	3.9	21.1	1.3	2.1	14.8	1	1	17	1.1	1	13.8	0	1.5	13.7
September	2.3	1	19.8	1	0	13.8	1	3	19	1	1	13.8	0	2	15.7
October	1	2	20.8	1	1	13.8	1	1	19	1.2	1.1	13.7	1.2	1	15.5
November	1.1	1.1	20.8	1	1.1	13.9	1	1	19	1	1.1	13.8	1	1	15.5
December	1.2	1.5	21.1	1.3	1.3	13.9	1	1	19	1	1.3	14.1	1	1.1	15.6

	Unit ID: 50a Bldg. 74-041-1a Deutz EB Generator Limit: 500 hrs			Unit ID: 51a Bldg. 74-041-2b Deutz EB Generator Limit: 500 hrs		
	2020	2021	Rolling Sum	2020	2021	Rolling Sum
January	1.4	1	13.3	1.4	0.9	13.2
February	1.5	0.9	12.7	1.6	0.9	12.5
March	0.6	1.5	13.6	0.6	1.2	13.1
April	1.1	1.5	14	1.1	1.2	13.2
May	1.2	1.3	14.1	1.1	1.3	13.4
June	1.2	1	13.9	1.2	1.3	13.5
July	1.1	1.4	14.2	1.2	1.3	13.6
August	1.2	1	14	1.1	0.9	13.4
September	1.3	0.9	13.6	1.3	0.9	13
October	1.1	0.75	13.25	1	0.75	12.75
November	1.1	1.2	13.35	1.2	1.4	12.95
December	0.9	1.2	13.65	0.9	1.1	13.15

Notes:
1. Rolling Sums = Calculated in accordance with Condition 12 of AQ0307MSS04.
2. Limits originate from Condition 12 of AQ0307MSS04.
3. Engine descriptions and building numbers updated in accordance with the Title V renewal application and Application to revise MSS04.

Diesel Eng* **Units 13-17, 27, 30, 32-36, 39-42, 50a, 51a Monthly Hours of Operation**
Facility: **Eareckson Air Station**
AQ0307MSS04, Cond. 12
Reported in accordance with AQ0307TVP03, Rev. 2

	Unit ID: 13 Bldg. 3057 Detriot Firewater Pump #2 Limit: 1,000 hrs			Unit ID: 14 Bldg. 3057 Detriot Firewater Pump #1 Limit: 1,000 hrs			Unit ID: 15 Bldg. 4011 Clarke Fire Water Pump Limit: 500 hrs			Unit ID: 16 Bldg. 3052 Clarke Fire Water Pump #1 Limit: 500 hrs			Unit ID: 17 Bldg. 3052 Clarke Fire Water Pump #2 Limit: 500 hrs		
	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum
January	4.3	3.3	33.19	0	0	0	0.1	0.1	1.2	2	10.1	39.6	2.5	2	49.3
February	2	2.5	33.69	0	0	0	0.1	0.1	1.2	2	2	39.6	2	2	49.3
March	3	2.5	33.19	0	0	0	0.1	0.1	1.2	3	2	38.6	3	2	48.3
April	3	2	32.19	0	0	0	0.1	0.1	1.2	3	2	37.6	2	2	48.3
May	5.3	2.9	29.79	0	0	0	0.1	0.1	1.2	4.5	2.6	35.7	2.5	4	49.8
June	2	2.1	29.89	0	0	0	0.1	0.1	1.2	2.1	2	35.6	2	2	49.8
July	3.75	2.3	28.44	0	0	0	0.1	0.1	1.2	2	2	35.6	5	2	46.8
August	2.53	2.6	28.51	0	0	0	0.1	0.1	1.2	2.2	2.5	35.9	3	2.5	46.3
September	2	1.6	28.11	0	0	0	0.1	0.1	1.2	2.1	2.5	36.3	10.5	2.1	37.9
October	1.51	2.6	29.2	0	0	0	0.1	0.1	1.2	4.6	2.5	34.2	13.3	2.5	27.1
November	3.2	5.1	31.1	0	0	0	0.1	0.1	1.2	2	2	34.2	2	2	27.1
December	1.6	1.8	31.3	0	0	0	0.1	0.1	1.2	2	2	34.2	2	2	27.1

	Unit ID: 27 Bldg. 76-558 Mitsubishi EB Generator Limit: 500 hrs			Unit ID: 30a Bldg. 3049 Caterpillar EB Generator Limit: 300 hrs			Unit ID: 32 Bldg. 4014 Mistsubishi EB Generator Limit: 300 hrs			Unit ID: 33 Bldg. 4014 Mistsubishi EB Generator Limit: 300 hrs			Unit ID: 34 Bldg. 600 Caterpillar EB Generator Limit: 300 hrs		
January	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum
February	1.5	1	13.3	1	1	15	0.8	0	4.3	1	1	16	0	1	16
March	1	1	13.3	2	1	14	1.3	0	3	1	0	15	1	1	16
April	1	1	13.3	1	1	14	0	0	3	0	1	16	1	1	16
May	1.1	1.1	13.3	1	1	14	1	0	2	1	2	17	1	1	16
June	1.4	1	12.9	1	2	15	1	0	1	5	1	13	2	2	16
July	1	1	12.9	1	1	15	0	0	1	0	1	14	2	1	15
August	1.8	1	12.1	2	1	14	1	0	0	1	1	14	2	1	14
September	1.2	1.3	12.2	2	2	14	0	0	0	2	1	13	2	1	13
October	0	1.2	13.4	1	1	14	0	1	1	2	2	13	0	1	14
November	1.4	1	13	1	1	14	0	55	56	1	99	111	2	2	14
December	1	1.1	13.1	1	1	14	0	0	56	0	0	111	1	1	14
	1.4	1	12.7	1	1	14	0	1	57	2	0	109	1	1	14

	Unit ID: 35 Bldg. 609 Cummins EB Generator Limit: 500 hrs			Unit ID: 36 Bldg. 754 Caterpillar EB Generator Limit: 300 hrs			Unit ID: 40 Bldg. 628 Caterpillar EB Generator Limit: 300 hrs			Unit ID: 41 Bldg. 718 Cummins EB Generator Limit: 500 hrs			Unit ID: 42 Bldg. 775 Cummins EB Generator Limit: 500 hrs		
	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum	2021	2022	Rolling Sum
January	1.5	1.1	20.7	1.5	1.1	13.5	1	1	19	1	1	14.1	1.5	1	15.1
February	1	1.3	21	0.3	1.1	14.3	2	1	18	0.8	1.1	14.4	0.5	1	15.6
March	1	1	21	1.2	1	14.1	1	1	18	1.1	1.1	14.4	1.3	1	15.3
April	1	1	21	1	1	14.1	1	1	18	1.1	1.2	14.5	1	1	15.3
May	1	1.1	21.1	2.4	1	12.7	1	1	18	1.2	1	14.3	1.1	1	15.2
June	1.1	3.7	23.7	0.9	2.9	14.7	1	4	21	1.2	1.1	14.2	1.6	1	14.6
July	5	1.5	20.2	1.1	2.9	16.5	5	1	17	2.2	1	13	2	1	13.6
August	3.9	1	17.3	2.1	1.2	15.6	1	1	17	1	1	13	1.5	1	13.1
September	1	1	17.3	0	1.3	16.9	3	2	16	1	1	13	2	1	12.1
October	2	2	17.3	1	21.5	37.4	1	2	17	1.1	2.4	14.3	1	1.2	12.3
November	1.1	1.1	17.3	1.1	2	38.3	1	1	17	1.1	1.1	14.3	1	1.2	12.5
December	1.5	1.1	16.9	1.3	0.6	37.6	1	1	17	1.3	1.1	14.1	1.1	1	12.4

	Unit ID: 50a Bldg. 74-041-1a Deutz EB Generator Limit: 500 hrs			Unit ID: 51a Bldg. 74-041-2b Deutz EB Generator Limit: 500 hrs		
	2021	2022	Rolling Sum	2021	2022	Rolling Sum
January	1	1.3	13.95	0.9	1.3	13.55
February	0.9	1.05	14.1	0.9	1	13.65
March	1.5	1	13.6	1.2	1.1	13.55
April	1.5	1	13.1	1.2	1	13.35
May	1.3	1.3	13.1	1.3	1.3	13.35
June	1	1.1	13.2	1.3	1.1	13.15
July	1.4	1.1	12.9	1.3	1.1	12.95
August	1	1	12.9	0.9	1.1	13.15
September	0.9	1	13	0.9	1.9	14.15
October	0.75	0.8	13.05	0.75	0.8	14.2
November	1.2	0.7	12.55	1.4	0.7	13.5
December	1.2	0.6	11.95	1.1	0.6	13

Notes:
1. Rolling Sums = Calculated in accordance with Condition 12 of AQ0307MSS04.
2. Limits originate from Condition 12 of AQ0307MSS04.
3. Engine descriptions and building numbers updated in accordance with the Title V renewal application and Application to revise MSS04.

Attachment D:
Emergency Engine PTE Calculations (MS Excel ® Spreadsheet)