APPLICATION TO REVISE OUTER CONTINENTAL SHELF PREVENTION OF SIGNIFICANT DETERIORATION PERMIT TO CONSTRUCT # R10OCS/PSD-AK-09-01

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Contents

Page

Introduction 1

Permit Revision Requests 5

1 Discoverer Main Generators: Revise Emission Limits for NOx and Remove Emission Limits for NH3 5
1.1 Background 5
1.2 PSD Permit Limits 6
1.3 Efforts to Achieve Emission Limits 6
1.3.1 DEC Marine Control Equipment 7
1.3.2 CleanAIR Systems E-POD Control Technology 9
1.4 Shell Testing and Efforts to Achieve Emission Limits 11
1.4.1 Engineering Tests at NC Machinery 11
1.4.2 Emission Testing at Vigor Shipyard 14
1.5 BACT Proposal in June 28, 2012 Permit Revision Application 15
1.5.1 BACT for NOx Emission from Engines at Constant Load 16
1.5.2 BACT for Ammonia Emissions 25
1.5.3 Administrative Order on Consent 26
1.6 Revise NOx Emission Limits to Accommodate Operational Realities 27
1.6.1 Issues with E-POD Controls in 2012 27
1.6.2 Excess Emissions and Permit Deviations 29
1.6.3 Efforts to Achieve PSD Permit Limits 31
1.6.4 Proposed BACT Limit for NOx Emissions 33
1.6.5 Compliance Monitoring 41
1.6.6 Proposed Revisions to Permit Conditions 42
1.7 Compliance with Ambient Air Quality Standards and PSD Increments 45

2 Substitute Catalytic Diesel Particulate Filters for Oxidation Catalyst Units 47
2.1 Emission Units with CDPFs substituted for Oxidation catalysts 47
2.2 Catalyzed Diesel Particulate Filters Control Efficiency 47
2.3 Location and Configuration of CDPF 48
2.4 Oxidation Catalyst Monitoring, Record-keeping and Reporting Requirements 48
2.4.1 Generator Engine Oxidation Catalyst MRR Permit Conditions 48
2.4.2 Mud Line Cellar Air Compressor Engine Oxidation Catalyst Monitoring 49
2.5 Identification of Monitoring Equipment Installed on CDPF 50
2.6 Proposed Permit Term Revisions 53

3 Rated Capacity for Emission Units 57
3.1 Introduction 57
3.2 Noble Discoverer 57
3.3 Nanuq (OSR Vessel) 58

4 Nanuq Particulate Matter Emission Limits ... 61
4.1 Background ... 61
4.2 Basis for Existing Emission Limits ... 62
4.3 Nanuq PM Source Test Results ... 62
4.4 Improvements to Nanuq Engines and CDPFs ... 62
4.5 June 2012 Source Tests ... 63
4.6 Proposed Revised Particulate Matter Limits ... 64
4.6.1 Requested PM Emission Limits and Compliance Monitoring Method ... 64
4.6.2 Proposed Permit Text Revisions ... 65
4.7 Compliance with Ambient Air Quality Standards and PSD Increments ... 66

5 Revise Permit Conditions for Crane and Cementing Unit Engines ... 67
5.1 Request to Remove CDPFs from Crane and Cementing Unit Engines ... 67
5.1.1 PSD Permit Limits ... 70
5.1.2 Efforts to Achieve PSD Permit Limits ... 70
5.1.3 BACT Re-evaluation ... 71
5.2 Request to Increase the Crane and Cementing Unit Engines Hourly NOx Mass Emission Limit ... 76
5.2.1 Background ... 77
5.2.2 Relevant PSD Permit Conditions for NOx ... 77
5.2.3 Efforts to Achieve PSD Permit Conditions ... 78
5.2.4 Proposed Permit Revisions Relevant to Crane and Cementing Unit Duty Cycle ... 78
5.3 Request for Option to Replace the Crane and Engine ... 78
5.3.1 BACT Analysis for Replacement Crane ... 79
5.3.2 Proposed Permit Revisions Relevant to Crane Replacement ... 79
5.4 Proposed Permit Revisions ... 79
5.4.1 Proposed Permit Revisions Relevant to Removing CDPFs ... 79
5.4.2 Proposed Permit Revisions Relevant to a Higher Hourly Use ... 82
5.4.3 Proposed Permit Condition Authorizing Crane Replacement ... 82
5.5 Compliance with Ambient Air Quality Standards and PSD Increments ... 83

6 Request to Revise Conditions that Apply During Engine Startup Periods ... 85
6.1 Background ... 85
6.1.1 Required Catalytic Control Devices ... 85
6.1.2 Catalytic Control Device Startup Deviation Reports ... 86
6.2 PSD Permit Limits ... 87
6.3 Efforts to Achieve PSD Permit Limits ... 88
6.4 BACT Re-evaluation ... 88
6.5 Proposed Permit Revisions ... 92
6.6 Compliance with Ambient Air Quality Standards and PSD Increments ... 93

7 Supply Ship Emission Controls ... 95
7.1 Permit Limits ... 95
7.2 Source Test Results and Permit Compliance ... 95
7.3 Proposed Permit Revisions ... 96
7.3.1 Proposed Permit Limits ... 97

7.4 Compliance with Ambient Air Quality Standards and PSD Increments 97

8 Eliminate Permit Conditions for Electrified Units 99

8.1 Proposed Permit Changes 99

List of Tables

Table 1-1: Summary of Source Test Results 15
Table 1-2: Comparison of Current D399 Limits to Transitional Tier 4 Limits, and Similar Source Permit Limits 18
Table 1-3: Comparison of Current D399 Limit to Transitional Tier 4 Limits, and Other Relevant BACT Determinations 20
Table 1-4: Analysis of NOx Emissions Testing 24
Table 1-5: Potential Ammonia Emissions From Discoverer Generator Engines 26
Table 1-6: 2012 Excess Emission & Permit Deviation Reports, Units FD-1-FD-6 30
Table 1-7: Generator Engine NOx Mass Emissions 41
Table 2-1: Discoverer Emission Units with CDPFs substituted for Oxidation catalysts 47
Table 2-2: Control Effectiveness Used for Oxidation Catalysts and CDPFs 48
Table 2-3: Measurements Included in the CMS with Thresholds 51
Table 2-4: Sensor Specifications, Signal Processing and Transmittal 51
Table 5-1: Engine Exhaust Temperature Summary 69
Table 5-2: RBLC Determinations for Small Diesel-fired Engines 72
Table 5-3: Cost for crane engine replacement 74
Table 5-4: Combined Crane Emissions and Cost of Emission Reduction using new-technology engines (@ 545 kW) 75
Table 5-5: Cost for Cementing Engine Replacement 76
Table 5-6: Cementing Engine Emissions and Cost Effectiveness Analyses 76
Table 5-7: Hourly NOx Mass Emission Limit Exceedance Events for Cranes 77
Table 6-1: Required Catalytic Control Devices for the Discoverer and Associated Fleet 85
Table 6-2: Catalytic Control Device Startup Deviation Reports 86
Table 7-1: Analysis of Supply Vessel Compliance with PM Emission Limits 96

List of Figures

Figure 1-1: Urea Crystallization within the FD-4 E-POD 29
Figure 1-2: Increase in FD-1 Average Generating Rate 33
Figure 1-3: FD-1 NOx Emissions Cumulative Frequency Plot 35
Figure 1-4: FD-2 NOx Emissions Cumulative Frequency Plot 36
Figure 1-5: FD-3 NOx Emissions Cumulative Frequency Plot 37
Figure 1-6: FD-4 NOx Emissions Cumulative Frequency Plot 38
Figure 1-7: FD-5 NOx Emissions Cumulative Frequency Plot 39
Figure 1-8: FD-6 NOx Emissions Cumulative Frequency Plot 40

List of Appendices

Appendix A: Computer Simulations of the E-POD Configuration Within the Discoverer
Appendix B: E-POD Specifications
Appendix C: Discoverer Generator Emission Test Results
Appendix D: Ambient Air Quality Analysis
Appendix E: CleanAIR Manufacturer Guarantee
Appendix F: CleanAIR Product Specification for HiBACK Units
Appendix G: Caterpillar 3608 Data Sheets
Appendix H: Nanuq Fuel Consumption/Engine Load Data
Appendix I: Crane Engine Temperature Data

Introduction

Shell Gulf of Mexico, Inc. acquired a number of exploration leases in the Chukchi Sea. On September 19, 2011, EPA issued a Prevention of Significant Deterioration (PSD) air quality permit for offshore exploration by the drill ship Discoverer at these lease sites (R10CS/PSD-AK-09-01) (the Permit). Responding to appeals, the Environmental Appeals Board denied or dismissed all petitions for review of the permit on January 12, 2012 and the Permit became final and effective on January 27, 2012.

This application seeks revisions to specific Permit conditions based on new information, source testing, and 2012's actual operating experience. It consolidates revision requests that Shell submitted to EPA on June 28, 2012, supplemental information submitted after June 28, and new revision requests.

June 28, 2012 Permit Revision Application

During Spring 2012, Shell conducted hundreds of source tests on emission units on the Discoverer and its associated fleet vessels. In the course of conducting these source tests and preparing for the drilling season, several issues surfaced warranting additional explanation or revisions to the Permit. Shell submitted a permit revision application to EPA on June 28, 2012, with supplements submitted on August 6 and 14, providing the basis for four revision requests. These requests are summarized below, with reference to their location in this consolidated application.

1. Discoverer main generator NOx and ammonia limits. Reference method emissions testing of the Discoverer's D399 engines demonstrated that the NOx and ammonia limits in the Permit were not feasible for this particular situation. Shell requested that the NOx emission limit associated with constant load operation and reference method testing be revised to 1.2 gram/kW-hr for FD1, FD3, FD4, and FD5 and to 2 grams/kW-hr for FD2 and FD6. Shell requested removal of the ammonia limit. In Chapter 1 of this consolidated application, Shell affirms its request to remove the ammonia limit but proposes to substitute a NOx emission limit that reflects variable engine load rather than the constant load operation that was the basis for the Permit emission limit and the June 28 proposed limit.

2. Use of CDPF controls in place of oxidation catalysts. Shell requested permit revisions to reflect the fact that Shell installed more-costly and better-performing catalytic diesel particulate filters on some engines in place of oxidation catalysts, including revisions to require appropriate monitoring, record-keeping, and reporting requirements. This request, presented in Chapter 2, is consistent with the June 28 application.

3. Requirement to test at rated capacity. The Discoverer generator engines and several other associated fleet engines are unable to operate at their rated capacity. For each such engine, Shell identified the maximum feasible operating rate and why the engine is limited. Chapter 3 addresses these requests and revises the June 28 requests on this topic.

4. OSR vessel PM limit. Shell requested that the PM10 and PM2.5 emission limits be revised for the oil spill response vessel based on emissions testing results showing that the vessel's PM emissions were higher than anticipated during the permit process. In August Shell amended its June 28 request to ask that the proposed limit be revised to 10 pounds per day. This request, presented in Chapter 4, is consistent with the request in the August 6 supplement to the June 28 application.

Based on Shell's June 28 permit revision application and its supplements, EPA issued an Administrative Compliance Order on Consent, effective September 7, 2012. EPA stated in the Order its expectation that it would not be able to take final agency action on the revision application during the 2012 drilling season. The Order makes several findings based on EPA's preliminary review of the application, imposes the revised limits proposed in the application, and imposes additional operational and reporting and monitoring requirements.

Additional Permit Revision Requests

The Discoverer first became an OCS source in the Chukchi Sea on September 6, 2012. The Discoverer operated in the Chukchi Sea for 43 days at a single drill site. This actual operating experience revealed a number of conflicts between actual operating conditions and permit requirements. This revision permit application incorporates the four requests from the June 28 permit application, with some revision, and adds the following requests prompted by the operating experience in September and October 2012:

5. Discoverer main generator NOx limits during actual operation. Operating experience shows that the E-POD control software is unable to respond fast enough to the frequent changes in operating load on the generators that occur during drilling operations. These frequent changes in operating load mean that the E-PODs are not able to achieve the 90 percent NOx reduction required by the Permit. While source testing shows that the E-PODs can meet the emission limits proposed in the June 28 application under constant load conditions, operating experience indicates those emission limits are not feasible for actual operation and do not represent BACT under real-world operating conditions. Based on data collected in 2012, Shell proposes, in Chapter 1, to establish a new emission limit of 6 g/kW-hr, which reflects BACT with variable engine load rather than the constant load operation that was the basis for the Permit emission limit and the June 28 proposed limit. Shell proposes to limit the annual NOx emissions increase resulting from this revision and proposed higher capacity operation of several smaller engines (discussed below) to 39 tons. Shell proposes to collect additional NOx emission data during operations in 2013, which may be used to adjust these limits again if the data shows that further revision is warranted.

6. Catalytic controls on low load engines. Shell installed catalytic controls (CDPFs, oxidation catalysts, or SCRs) on virtually all the engines on the Discoverer, including the cranes and cementing unit engines. Actual operating experience shows that the crane engines and the cementing engines operate at loads that are too low to maintain exhaust gas temperatures that allow effective emissions control by catalytic controls, making CDPFs an infeasible control technology for these two applications. Shell therefore requests, in Chapter 5, that the requirement for CDPFs on the crane and

cementing unit engines be rescinded and replaced with a requirement for good operating practices, which is BACT for these engines under actual operating conditions.

7. Catalytic controls during engine startup periods. The Permit requires Shell to measure exhaust gas temperature at the inlet to the control device every 15 minutes to confirm that catalyst-based control equipment is operating properly. If the exhaust gas temperature is below specified values, the Permit requires Shell to apply an uncontrolled emission rate in the emissions monitoring record for that time period on the assumption that the control equipment is not operating properly. In many cases, this resulted in Shell having to file a permit deviation or excess emissions report. These Permit conditions do not take into account the fact that engines are cold before startup and that it takes time for the engine and exhaust to reach the elevated operating temperature identified in the Permit. In Chapter 6 Shell requests that the Permit be revised to require best operating practices during engine startup.

8. Option to replace the cranes. In Chapter 5 Shell requests the option to replace the existing cranes and engines with others that meet the same BACT emission limits as the existing cranes (absent CDPFs).

9. Reduce supply ship PM emission limits. Recognizing that revisions requested in this application would increase fleet-wide potential emissions absent other reductions, in Chapter 7 Shell requests a corresponding reduction in allowable PM emissions from the supply ship. Based on source tests conducted in spring 2012, the Harvey Explorer and Harvey Spirit can comply with the proposed lower PM mass emissions limits without installing emission controls. Alternatively, Shell proposes to use other, yet to be identified supply vessels that would meet the Permit emission limits, including the proposed tighter PM limits. In the event that a supply ship proposed for use employs CDPFs to achieve the allowable PM emission limit, the application identifies CDPF monitoring requirements that would apply.

10. Revise crane and cementing unit hourly NOx mass emission limits. As explained in the 2010 PSD permit application, crane engines have a highly variable duty cycle. Shell estimated daily fuel consumption and emissions based on a duty cycle much lower than rated engine capacity. Actual 2012 operations, however, revealed higher hourly fuel consumption during some periods than was anticipated. Daily monitoring of hourly NOx emissions, which is based on fuel consumption, indicated that calculated hourly NOx emissions exceeded allowable NOx mass emissions eight times during the 2012 season.

    Although the need for high capacity use of the cementing engines was not demonstrated in 2012 operations, Shell anticipates that the hourly NOx limit for the cementing engines will occasionally be too restrictive. The current limit is also based on an expected daily fuel consumption distributed evenly among 24 hours. In Chapter 5, Shell proposes to eliminate the restriction on hourly duty cycle caused by the assumption of even distribution of the daily fuel limit and requests an increase in the hourly NOx mass emission limits for the crane and cementing unit engines.

11. Eliminate permit conditions related to electrified units. Table 1 of the Permit identifies a small cementing engine and two small logging winch engines as emissions units. Shell chose to electrify these operations prior to the beginning of the 2012 season. In Chapter 8, Shell proposes to eliminate all references and permit conditions related to these engines.

The need for these revisions derives in large part from the unique circumstances of this activity (drilling in the Arctic Ocean). Applying the PSD permitting rules to what are essentially mobile sources presents unique and difficult challenges. PSD permitting typically applies to future construction, either of a new or modified stationary source. In contrast, the Discoverer and most of the vessels in the associated fleet are existing mobile sources with existing engines built into the depths of each vessel's hull. Furthermore, the Discoverer and many of the associated fleet vessels are leased by Shell. At the time Shell prepared its application and BACT analysis, the Discoverer and other vessels were being leased and used by different companies. As a result, Shell's consultants had to rely on manufacturer literature and estimates in assessing emissions, the feasibility of control technologies, and the emission rates achievable by control technologies. In other words, the application, and thus the permit based on it, reflects what was theoretically achievable based on information available at the time.

Now that Shell has had the opportunity to test the emission units and controls, and then operate them in the Arctic for exploratory drilling purposes, it is in a better position to evaluate what those engines and controls can actually achieve when operated for their intended, permitted use. During the 43 days of operation in September and October 2012, the primary issue that arose is that the fluctuating engine loads in real world operation is inconsistent with emission limits established based on constant load. As noted above, the E-POD controllers did not respond quickly to startups and changing engine load for the main generators and the crane and cementing engines operated at loads so low the exhaust temperatures were insufficient for CDPF effectiveness.

The need for these revisions also results in part from the long permitting history for this project. It has been almost four years since Shell proposed PSD emission limits, and more than two years since EPA originally imposed PSD permit limits. In the interim, new and better emission unit information that would have supported revising some of those limits was developed. Shell submitted its initial Discoverer Chukchi Sea PSD application in December 2008, and submitted a replacement application in February 2009. EPA issued a Discoverer Chukchi Sea PSD permit in March 2010, and in December 2010, the Environmental Appeals Board remanded parts of the permit. In 2011, Shell submitted a number of application supplements addressing remand issues and in September 2011, EPA issued the revised PSD permit that is the subject of this revision request. Over these years there have been several changes, including use of a more refined and accurate model to demonstrate ambient air quality compliance, that provided a basis to revise limits. Shell acknowledges that the post-remand permit offered an opportunity to request emission limit revisions, but Shell was then and remains now committed to making every effort to meet the emission limits imposed by EPA. As noted above, Shell did not have actual emission factor data from emissions tests until only recently and as a result could not accurately determine the emission limits that would be achievable while simultaneously meeting stringent limits for multiple pollutants.

Permit Revision Requests

1 Discoverer Main Generators: Revise Emission Limits for NOx and Remove Emission Limits for NH3

This chapter provides the technical basis for revising the oxides of nitrogen (NOx) emission limits and removing the ammonia (NH3) emission limits for the Discoverer's main generator engines. It documents why specific permit terms should be revised or rescinded and the effect of these changes on emissions, other permit terms, the underlying ambient demonstrations, and compliance monitoring.

The following sections describe Shell's extensive efforts to meet Permit limits for the D399 engines, emission units FD-1 through FD-6, and the outcome of the source testing conducted in Spring 2012, before the 2012 operating season. The testing resulted in Shell proposing, in the June 28 revision application, revised emission rates that reflect Best Available Control Technology (BACT) during constant load operation. After the 2012 operating experience, however, Shell has concluded that BACT must take into account the actual operating mode of the Discoverer's generator engines. This revision application, accordingly, identifies and requests emission limits that reflect BACT during highly variable operating conditions. Shell proposes to conduct NOx emissions monitoring during the 2013 drilling season to collect additional emissions data and agrees to reconsider the NOx emission limits that apply to actual operating conditions after the 2013 drilling season.

1.1 Background

Six Caterpillar D399 generator sets (Emission Units FD-1 through FD-6) provide the primary systems power for drilling and ship utilities, and operate at varying loads throughout the drilling process. The engines burn ultra-low sulfur diesel (ULSD) fuel, and each is rated at 1,325 horsepower (hp). The normal ramping procedure is to operate the fewest number of engines needed to power the load; as load increases, operators add engines so that the power levels are targeted at 50 percent capacity or greater.

The PSD permit application for Discoverer operations in the Chukchi Sea provided a BACT analysis for all the sources on the Discoverer. Because there was virtually no precedent for BACT analyses on off-shore drill rigs, the BACT analyses necessarily focused on emission control experience at on-shore facilities. Shell's 2012 season operating experience showed that we underestimated how critical this distinction is when determining the feasibility of BACT-related emission limits.

The PSD permit application review of available control technologies for the D399 engines concluded that selective catalytic reduction (SCR) was the best technology for NOx emissions and an oxidation catalyst was the best technology for particulate matter (PM), carbon monoxide (CO), and volatile organic compound (VOC) emissions. SCR and oxidation catalysts are proven technologies for on-shore reciprocating engines, but Shell did not locate any examples of SCR and oxidation catalysts being retrofitted on older diesel engines located deep within a vessel hull. As discussed below, retrofitting SCR and oxidation catalysts on existing engines in a drill ship is extremely expensive (costing approximately $24 million initially), and is not cost-effective

when typical cost effectiveness criteria are applied. Despite being in a position to disqualify these controls based on cost, Shell committed to installing SCR. Shell's proposed BACT assessment was, therefore, essentially an exercise in determining the degree of NOx emission control the technology was capable of achieving. Given the scale of the costs, the emission limit ultimately proposed could logically be considered the Lowest Achievable Emission Rate (LAER).[1]

SCR technology involves injecting urea into the exhaust stream in the presence of a catalyst to convert NO_x to nitrogen and water. Ideally, the urea will reduce NO_x at a 1:1 ratio. However, because mixing within the exhaust stack is not ideal, a small portion of ammonia passes through the system and is released to the atmosphere; this is commonly referred to as ammonia slip. Ammonia slip is minimized using instrumentation that adjusts urea injection to engine load and other operational factors. The instrumentation includes a continuous NO_x sensor that adjusts the load-based urea injection algorithm as needed.

The BACT analysis indicated the anticipated vendor was DEC Marine AB, a Swedish company that by 2008 had installed NO_x emission control systems on more ships than any other company. With the DEC controls, Shell anticipated emission reductions to 0.5 grams NOx per kilowatt-hr, an 80 percent reduction of CO emissions, and a 50 percent reduction of PM emissions.

1.2 PSD Permit Limits

The Permit requires the installation and use of SCR and oxidation catalysts to control emissions from the main generator engines, and established the following emission limits in Condition C.3:

- NOx - 0.50 grams (g) per kilowatt-hour (kW-hr), EPA Method 7E
- NH3 - 5 parts per million by volume (ppmv), CTM 027 or 038
- PM - 0.127 g/kW-hr, EPA Method 5
- PM10 - 0.127 g/kW-hr, EPA Methods 201A and 202
- PM2.5 - 0.127 g/kW-hr, EPA Methods 201A and 202
- CO - 0.1790 g/kW-hr, EPA Method 10
- VOC - 0.0230 g/kW-hr, EPA Method 25A
- Visible Emissions: 20 percent averaged over any six consecutive minutes, EPA Method 9

1.3 Efforts to Achieve Emission Limits

Shell solicited SCR quotations from DEC and Mustang Cat in August 2008. Shell deemed the DEC proposal better suited for its purposes because of DEC's experience with marine installations and because its units were sized smaller, a key concern given the lack of overhead space in the Discoverer engine room above the D399 engines on which they were to be

[1] Note that Shell is not suggesting that the limit is LAER in this case. For purposes of this application, Shell accepts that EPA is processing the limit as BACT. Refer to footnote 12 for further explanation.

installed. Shell issued a purchase order to DEC in March 2009 to procure six of their vertical SCRs.

1.3.1 DEC Marine Control Equipment

Shell arranged to install the DEC SCR units and oxidation catalysts on the Discoverer generator engines in a Subic Bay (Philippines) shipyard. Installation of the control equipment took 120 days of shipyard time (from December 2009 through May 2010). Commissioning and air emissions testing started in May 2010, but the Discoverer was relocated to a Singapore shipyard in August to avoid typhoon season in the Philippines. Commissioning and testing continued in Singapore from September through November 2010. Although capital cost of the DEC emission control units was modest (approximately $750,000), the total cost to procure, engineer and design, install, and commission the units was $23.5 million.[2]

In three months of effort and nearly continuous involvement of engine and control technology specialists, the D399 engines with the DEC Marine SCR and oxidation catalysts were only occasionally able to meet the NOx limit and only once in more than 60 tests meet all the emission limits.[3] This was despite efforts by Shell to go beyond the manufacturer's design to achieve compliance, including procuring two different SCR catalysts other than those installed by DEC. Additional emissions testing performed with the new catalysts in place revealed that the high temperature catalyst did not perform well; it was found to be very fragile and crumbled inside the DEC unit during stack testing. The medium temperature catalyst performed well and appeared promising for gaseous pollutants, but PM emissions were typically 50 percent higher than the emission limit. After going beyond the original DEC design and devoting several months to a research and development project aimed at achieving all the emission limits imposed by the spring 2010 draft permits, it was clear that the Discoverer D399 engines equipped with the DEC Marine SCR and catalytic oxidation units were not physically capable of achieving the limits, leading Shell to search for supplemental and alternative control technologies.

In addition to looking for alternatives for the DEC SCR system, a solution called ULTRA BURN was identified as having a potential benefit to the installed DEC SCRs. In fall 2010, the decision was made to procure an ULTRA BURN system to install and test on a generator engine. The ULTRA BURN system did not, however, improve emissions performance.

Although eventually proven infeasible, another alternative identified was CSNOx. Shell determined that CSNOx was still in its Research & Development phase and not yet commercially tested, and therefore was not viewed as an alternative that could reliably reduce NOx to 0.5g/kW-hr.

The inability to consistently and simultaneously meet the NOx, NH3, and PM emission limits prompted the search for technologies that could complement the already installed DEC SCRs,

[2] Section 2 of an attachment to an August 14, 2012 letter from Susan Childs to EPA Region 10 provides additional detail regarding the cost of procuring, installing, and commissioning the DEC control equipment.

[3] Section 4 of an attachment to an August 14, 2012 letter from Susan Childs to EPA Region 10 provides additional detail regarding the 2010 testing of the DEC Marine control equipment.

particularly by further controlling PM because the oxidation catalysts were not achieving the level of control anticipated in the application concurrent with achieving the NOx emission limits. Two critical considerations were the limited space available with the DEC systems already installed and the need to limit backpressure created by the control devices to no more than 22 inches of water.[4] The DEC units already contributed 17 inches of backpressure, leaving only 5 inches for an additional PM control device.

Neither Mustang nor DEC offered particulate control devices with efficiencies greater than 50 percent. Using internet searches, a U.S. Maritime Administration study, and industry contacts, two vendors were identified in the search for PM reducing technology: Johnson Matthey and CleanAIR Systems.

Johnson Matthey proposed two options for particulate matter control: a passive regeneration solution and an active regeneration solution. Upon investigation, it was determined that the Johnson Matthey passive regeneration solution would have reached a point of PM saturation in approximately three hours and would thus require the engine to be removed from service to manually remove and clean the PM filter.

After consideration of the active regeneration option, Johnson Matthey declined to provide a PM reduction solution based on the following:

1. Johnson Matthey's active systems were almost always used on standby emergency engines that run a minimal amount and thus cannot achieve regeneration temperatures.
2. While marine applications were not anticipated to pose any special issues that would compromise integrity of the system, there were no documented marine cases for their active systems.
3. Active systems are extremely complex and placing six on an ocean going vessel is riskier than a land based system, which can be easily accessed for service.

CleanAIR Systems was unable to offer a PM-only solution that could meet the required PM emission reduction in the space available after the DEC SCR was installed.

After these investigations into alternatives, Shell concluded that there was no apparent retrofit system to the purchased DEC system available to meet the combination of NOx and PM emission limits, regardless of NH3 emissions.[5] Furthermore, to meet the NOx limit, the commercially available DEC system would have needed to be re-configured, without any assurances of success.

Despite having spent nearly $24 million on procuring, installing, and testing the DEC emission control system, Shell re-initiated its search for a commercially available control option that would allow the engines to meet all emissions limits and fit into the available constrained space in the Discoverer engine room. CleanAIR was the only vendor identified that offered an integrated

[4] Backpressure is the resistance to exhaust flow caused by downstream piping, silencers, and emissions control equipment. Engines are designed to operate with a certain range of acceptable backpressure.

[5] The feasibility of installing a CDPF downstream of the DEC SCR is addressed in sections 4.4.1 (pages 68-71) of the Statement of Basis for the January 2010 proposed PSD permit for Discoverer operations in the Chukchi Sea.

package with a better combination of emissions reductions than the DEC system. CleanAIR offered a recently developed “E-POD” control system integrating an SCR unit with a newly developed catalytic diesel particulate filter (CDPF). In the absence of alternatives, the decision was made to replace the DEC SCRs with CleanAIR E-PODs. The cost of removing the DEC control equipment and procuring and installing E-PODs exceeded $7 million.

1.3.2 CleanAIR Systems E-POD Control Technology

Caterpillar CleanAIR Systems is a worldwide leader in custom-designed exhaust after-treatment solutions, including oxidation catalyst, catalyzed diesel particulate filters, SCR systems, and a hybrid “E-POD” technology. The E-POD combines an oxidation catalyst or catalytic diesel particulate filter (CDPF) with an SCR system in a silenced housing, custom designed to fit existing installations with minimal site disruption or re-engineering. In 2010, Caterpillar acquired CleanAIR Systems and E-PODs are now commonly applied to Caterpillar engines.

Given the remoteness of the Arctic OCS lease areas, reliability is one of the primary considerations in design and acquisition of new equipment. Consequently, a primary reason Shell selected the E-POD technology was that CleanAIR had installed more than 300 custom-designed E-PODs worldwide. Given that the E-PODs were sold by a Caterpillar Company, Shell also expected the CleanAIR staff to be more familiar with Caterpillar engines such as the D399 generator engines. Furthermore, CleanAIR designed the systems for up to 90% reduction of NOx, CO, and VOC emissions and 85 percent reduction of PM emissions, and targeted 10 ppm ammonia slip.

Although Shell could have purchased E-PODs with an oxidation catalyst, the testing of the DEC oxidation catalyst indicated that a higher degree of PM control was required. Consequently, Shell purchased E-PODs that use a CDPF with an electric heater to maintain exhaust temperatures high enough for the CDPF to regenerate during extended low load operation. Placing the CDPF before the SCR improves the SCR’s efficiency by transforming the various NOx compounds to the most easily converted compound, NO2, and also protects the SCR from performance-degrading soot build up. Substituting the CDPF for the oxidation catalyst does not reduce space available for the mixing zone or SCR catalyst because the space devoted to CO and PM control is the same with either configuration. While both options are guaranteed to provide 90 percent reduction in CO emissions, CleanAIR guarantees 85 percent control of PM emissions with a CDPF but only 20 percent control of PM emissions with an oxidation catalyst. The better PM control occurs because an oxidation catalyst only reduces the soluble organic fraction of PM, while a CDPF also traps particulate matter.

Caterpillar offers the E-POD in a horizontal or vertical configuration. The horizontal configuration is typically used in land based applications because its lower overall height is easier to mount to the container style structures used in the land-based market and easier to transport because of its lower height, but its large footprint covers the top of the engine, hindering engine service access. The vertical configuration is better for marine markets because it fits well within traditional stack structures and maximizes access to the top of the engine for service.

SCR performance is affected by many parameters, of which the most critical are:

1. Urea/ammonia distribution at the face of the catalyst.
2. Residence time (the time the urea has to transform to ammonia from the time it is injected to the time it enters the catalyst).

Mixers must be carefully designed to achieve urea distribution targets without creating so much exhaust backpressure that the engine emits more pollution. Mixers improve urea distribution by:

1. Creating swirl and turbulence.
2. Contracting and expanding the flow stream.
3. Reducing urea droplet size when urea impinges on the mixer blade surfaces.

Residence time for reactions to occur requires a certain minimum volume because the exhaust flow rate of the engine is fixed. In a vertical configuration, the cross-sectional area of the unit is set by the required space velocity for the catalyst, the permissible back pressure, and spatial constraints within the vessel. With the cross-section fixed, the length is chosen to provide the proper residence time. In cases where residence time is low because of length restraints, there is a relatively greater ammonia injection rate required to achieve the desired NOx reduction, and there is greater ammonia slip.

Designing and installing the best available control technology for the Discoverer generator engines was challenged by the fact that the Discoverer “stationary source” is not at all stationary – it works throughout the world; it is not owned but leased, and changes to the vessel require approval by the owner because it potentially affects suitability of the drill rig for other clients and projects; the engines are existing and may be expected to have higher exhaust concentration directed to the control device; and the engines are located two levels below deck, in a location where installing emission control equipment had never been anticipated.

Thus, in addition to reliability and emission control performance, a critical consideration in the design of the emission control system in this case was the limited space available for emission controls and the need for access to the catalysts. The generator engines are located two levels below deck, and there is very limited opportunity to install additional equipment. Noble Corporation (Noble), the owner of the Discoverer, retained Zentech Incorporated of Houston to prepare computer models of the Discoverer interior to assist in determining how large an E-POD could be fit below deck and how the E-PODs and associated exhaust ducts could be installed in the Discoverer engine room. Appendix A provides isometric “snapshots” of the computer model Zentech prepared. The engines are not shown in these figures, but the engines lie directly under the E-PODs and take up virtually the entire level below the mezzanine deck.

Spatial restrictions in the Discoverer’s engine room necessitated two E-POD designs. Engine location permitted a primary design (hereafter E-POD 1345) to be used for engines FD1, FD3, FD4, and FD5 and a secondary design (hereafter referred to as E-POD 26) for engines FD2 and FD6. Both designs are approximately 5 feet by 4 feet in cross section. The E-POD 1345 design is 19 feet tall; E-POD 26 design is about 32 inches shorter. The volume of catalyst is the same in both designs; the difference in length comes out of the urea mixing area because inlet and outlet sections must also be controlled to balance flow distribution to the CDPFs and backpressure. The E-POD 1345 units contain two mixers and the E-POD 26 units contain one

mixer. Computational Fluid Dynamics studies revealed that two mixers in the E-POD 26 unit would be too close to allow the flow to expand and contract between them. Because this reduced the effective residence time and degraded performance, only one mixer is used in the E-POD 26 units.

CleanAIR acknowledges that it has designed E-POD systems that can perform better than those installed on the Discoverer. However, the Discoverer E-PODs are custom-designed for the space that is available, and CleanAIR affirms that their design targets are the best that one can hope to achieve with current technology in the space available.

Electronic controls for the E-PODs adjust the quantity of urea injected based on a NOx reduction target and measured NOx emissions downstream of the SCR. CleanAIR recommends establishing a NOx reduction target of 90 percent for the E-POD 1345 and 86 percent for the E-POD 26 for the best long-term performance and system stability, but more aggressive NOx reduction (to 93 percent for E-POD 1345 and 88 percent for E-POD 26) are also acceptable.[6] CleanAIR explains that attempting too high a NOx reduction is counterproductive, because the controller attempts to inject greater and greater quantities of urea. The downstream sensor does not distinguish between NOx and NH3, so it reads the increasing NH3 slip as NOx and injects still more urea. Eventually the controller will reach its limit and reset itself. CleanAIR suggests a target no greater than 93 percent to ensure stable operation.[7]

Appendix B provides a cut-away drawing of the vertical E-POD designed and constructed for the Discoverer. The drawing indicates exhaust from the engine enters from the bottom of the E-POD and passes through diesel particulate filters. The partially cleaned exhaust then enters a mid-section where urea is injected and mixed into the exhaust air before passing through the SCR catalyst blocks. Cleaned exhaust exits the E-POD at the top of the control device.

Appendix B also provides dimensional drawings of the E-PODs. The E-POD 1345 units have the same exterior dimensions but the E-POD inlet port is off-center on the design for engines 4 and 5. The E-POD 26 design is required for generator engines 2 and 6 because of overhead space constraints. Above FD-2, there is an old and relatively delicate electrical cable tray that would be cost-prohibitive to relocate, even if the vessel owner allowed it. Above FD-6, there is reduced headroom, necessitating a shorter E-POD.[8]

1.4 Shell Testing and Efforts to Achieve Emission Limits

1.4.1 Engineering Tests at NC Machinery

[6] Email from Brian Huffman, Caterpillar Emissions Solutions. June 28, 2012.
[7] Section 5 of an attachment to an August 14, 2012 letter from Susan Childs to EPA Region 10 provides additional detail regarding the consequences of attempting too high a NOx control rate on the E-PODs
[8] Sections 6 and 7 of an attachment to an August 14, 2012 letter from Susan Childs to EPA Region 10 provide additional detail regarding how spatial constraints affected the size and configurations of the E-PODs for FD-2 and FD-6.

Given the challenges experienced in source testing the Discoverer generator engines in 2010 and because it did not have access to the vessel, Shell elected to conduct preliminary engineering tests of an E-POD controlled D399 engine at NC Machinery in Tukwila, WA during Spring 2012, with the objective of determining engine and control settings to achieve compliance during formal emissions tests of the Discoverer engines to be conducted later when the vessel was available and the E-PODs installed. As discussed below, Shell spent several months and more than a million dollars in an unsuccessful effort to meet all the permit emission limits.

Shell purchased a Caterpillar D399 1325 hp industrial engine identical to the Discoverer engines and retained NC Machinery to overhaul the engine to the manufacturer's specifications. In addition, a generator of the same make and model as those on the Discoverer was located and refurbished. Other permit equipment requirements, such as the closed crankcase ventilation system, were also installed on the engine.

Shell directed CleanAIR to ship one E-POD 1345 and one E-POD 26 to NC Machinery. A substantial steel frame nearly 50 feet tall was designed and fabricated to support the E-POD above the engine. A CleanAIR technician and a number of Caterpillar staff were involved in preparing the engine and E-PODs for the tests and efforts to demonstrate compliance during the tests.

Shell retained the Avogadro Group to conduct emission tests of the D399 engine with the E-PODs. The initial tests of the E-POD 1345 unit indicated compliance with CO, VOC, and particulate matter emission limits, but NOx and ammonia slip exceeded permit limits. A series of engine loads were selected in which to measure emissions across the likely operating spectrum. Testing took place at 100 percent load (which ranged between 924 kW and 910 kW, depending on the engine timing); at intermediate loads (875 kW, 825 kW, 775 kW, 700 kW); and at 50 percent load (455-462 kW). The fuel injection timing was varied between Top Dead Center (TDC) and 4 degrees retarded and NOx reduction targets were varied from 91 to 97 percent in an effort to comply with both NOx and ammonia emission limits. Eventually, Shell determined that the highest level of NOx reduction was obtained by retarding the engine timing 2 degrees and selecting a NOx reduction target of 97 percent. This combination enabled compliance with the NOx emission limit but ammonia slip remained relatively high.[9] Furthermore, wide variations in concentrations were noted, indicating instability of the control system. Subsequent commissioning work noted instability at control levels higher than about 93%.

In an effort to reduce ammonia slip, a layer of AMOX© catalyst bricks were installed in the E-POD 1345 and the tests were repeated. The addition of these catalyst bricks resulted in a slightly lower ammonia slip, but emissions still exceeded 5 ppm. However, the NH3 reduction was accompanied by a slight increase in NOx emissions.

[9] Note that Avogadro employed FTIR to obtain real-time ammonia emissions information. The PSD permit requires a wet chemistry method that takes more than a week to complete.

CleanAIR technicians hypothesized that the persistent ammonia slip level was the result of exhaust 'blow-by' that was occurring in the spaces between the catalyst bricks (i.e., some of the exhaust was traveling through these spaces rather than through the catalyst where it could be converted). CleanAIR suggested sealing the spaces between the bricks with ceramic rope. A design was engineered and sent to NC Machinery. Subsequent testing with the ceramic rope installed revealed an increase in both ammonia slip and NOx emissions.

Over the course of three weeks between March 30 and April 20, 59 source tests were performed in an attempt to find the combination of engine parameters and catalyst configurations that would achieve compliance with NOx and NH3 emission limits. None of the tests were entirely successful. Using a NOx reduction target of 97 percent, which is well outside the manufacturer's recommendations, NOx emissions of less than 0.4 g/kW-hr were obtained, with concurrent NH3 emissions of 10-26 ppm.

Given that ammonia slip was well above the permit limit with the E-POD 1345, there was concern that the E-POD 26 would show even higher ammonia slip because its reduced length did not allow for as much urea/exhaust mixing. In order to reduce the anticipated ammonia slip, the design of E-POD 26 included a layer of AMOX bricks. These bricks are essentially oxidation catalysts designed to oxidize NH3 to nitrogen.

Testing commenced on April 14 with the engine timing (and fuel injection) 2 degrees retarded and an aggressive NOx reduction target of 97 percent. From the outset, the ammonia slip was higher than with the E-POD 1345. Because both NOx and ammonia emissions exceeded the permit limits, engine timing was adjusted to 4 degrees retarded and retested at 700 kW with negligible improvement.

Because NOx emissions were higher than anticipated, it was posited that the row of AMOX bricks was converting excess ammonia into NOx. Accordingly, a second series of tests was performed with two changes: the AMOX bricks were removed, and the cooling capacity of the inlet air was doubled. By cooling the inlet air, it was hoped that the NOx level would be reduced.

The second round of tests resulted in higher NOx concentrations and higher ammonia slip than the first round of tests. In all, 10 tests were conducted with the E-POD 26 between April 13 and April 20. Using a NOx reduction target of 97 percent, which is well outside the manufacturer's recommendations, NOx emissions of 0.7 to 0.83 g/kW-hr were obtained, with concurrent NH3 emissions of 12-32 ppm.

In summary, Shell invested several months and more than a million dollars at NC Machinery in an effort to achieve the PSD permit emission limits for the Discoverer D399 engines. While BACT is intended to reflect emission limits and control equipment that is proven and commercially available, in Tukwila Shell conducted a second research program to try to achieve all the emission limits required by the PSD permits. This reflects an extraordinary level of effort, especially when one considers that the annual NOx emissions from the diesel generators are on the order of 10 tons.

Despite this effort, the engineering tests indicated that the E-PODs could not achieve the ammonia limit with either the E-POD 26 or the E-POD 1345 design, and could not achieve the NOx limit with the E-POD 26 design. The tests showed that E-POD 1345 could meet the NOx limit if the controller was forced to attempt a 97 percent NOx reduction, but this is well outside the manufacturer's recommending operating condition and significant instability in the measured concentrations was observed. While the engineering tests at aggressive NOx reduction targets demonstrates Shell's efforts to achieve compliance with all permit limits, compliance with both NOx and NH3 limits was still not achieved. Shell concluded that actual tests of the D399 engines on the Discoverer would be conducted with E-PODs targeting NOx reductions within the range of operating conditions recommended by the manufacturer to ensure proper long-term operation of the control systems.

1.4.2 Emission Testing at Vigor Shipyard

In late April, Shell moved the two E-PODs it used in Tukwila to Vigor Shipyard in Seattle for installation on the Discoverer with four other E-PODs. Altogether, Shell spent more than $2 million to acquire six E-PODs and deliver them to the Discoverer and another $5 million for installation.[10]

Shell retained the Avogadro Group to conduct emission tests of the actual D399 engines that power the main generators on the Discoverer. The engines were tuned by Caterpillar technicians and set up to match the fuel injection setting determined at NC Machinery to produce the lowest NOx emissions. The E-PODs were commissioned by a CleanAIR technician, with the controller set to achieve 93 percent NOx reduction. The target NOx reduction was reduced from the 97 percent target during testing at NC Machinery to be more consistent with the manufacturer's recommended operating practice.

Avogadro began testing the D399 generator engines installed on the Discoverer on May 28 and finished the testing June 8. As initially proposed in a January 11, 2012 letter from Shell's Susan Childs to Natasha Greaves at EPA, during the tests the engines were operated at less than the engines' rated capacity. The D399's were tested at 800 kW rather than the name plate rating of 980 kW because Noble has established 800 kW as the maximum operating rate for the generators and has installed an electrical distribution system with controls that limit the engines' operating rate accordingly. Consequently, the engines were tested at 800 kW to represent full load and at 600 kW and 400 kW to represent 75 percent and 50 percent load, respectively.[11]

The test results presented in Table 1-1 indicate compliance with CO, PM10, PM2.5, and VOC emission limits by comfortable margins. However, NOx emissions and NH3 emissions exceed their respective emission limits. Additional detail on the NOx and NH3 tests is provided in Appendix C.

[10] Section 3 of an attachment to an August 14, 2012 letter from Susan Childs to EPA Region 10 provides additional detail regarding the cost of procuring, installing, and commissioning the E-PODs.

[11] The rating of the generator engines is addressed again in Section 3 of this application.

Shell downloaded data collected by the E-POD control system during each engine test and sent the data to CleanAIR technicians to confirm that the engines and E-PODs were operating properly during the tests. CleanAIR reviewed the data and concluded that the systems "are operating within acceptable performance specifications." CleanAIR acknowledged the variability in emission test results, and suggested the variability can be attributed to:

1. Variations among the E-POD's themselves
2. Testing data accuracy and/or procedure accuracy
3. Engine out emissions levels - This is the biggest variable as D399 are not electronically controlled engines and can have significant differences in emissions. This can be due to many factors including engine age, wear, and injector performance.

Table 1-1: Summary of Source Test Results

Source	Load (%)	Oxides of Nitrogen		Ammonia	Carbon Monoxide	Total PM		VOC
		lbs/hr	g/kW-hr	ppmv	g/kW-hr	lbs/day	g/kW-hr	g/kW-hr
FD-1	100	0.31	0.17	91	0.0208	3.132	0.0703	0.0076
	75	0.27	0.19	81	0.0067	1.201	0.0359	0.0081
	50	0.30	0.32	38	0.0097	0.251	0.0113	0.0097
FD-2	100	2.34	1.26	6	0.0037	1.376	0.0309	0.0075
	75	1.91	1.37	5	0.0034	0.832	0.0249	0.0082
	50	1.44	1.55	5	0.0046	1.027	0.0461	0.0097
FD-3	100	0.64	0.34	26	0.0367	1.469	0.0330	0.0075
	75	0.72	0.52	8	0.0203	0.604	0.0181	0.0080
	50	0.54	0.57	6	0.0906	0.966	0.0428	0.0097
FD-4	100	0.81	0.43	21	0.0189	2.111	0.0471	0.0069
	75	0.45	0.33	28	0.0089	0.486	0.0146	0.0075
	50	0.69	0.75	10	0.0162	0.363	0.0163	0.0095
FD-5	100	1.43	0.77	16	0.0181	0.876	0.0197	0.0069
	75	0.90	0.65	19	0.0065	0.848	0.0254	0.0076
	50	0.75	0.81	14	0.0148	0.859	0.0385	0.0094
FD-6	100	2.11	1.14	10	0.0089	1.010	0.023	0.0076
	75	1.47	1.06	13	0.0086	1.492	0.045	0.0079
	50	1.05	1.13	8	0.0042	0.430	0.019	0.0095
BACT Limit			**0.50**	**5**	**0.1790**		**0.127**	**0.0230**
Mass Limit		**4.64**				**28.3**		

1.5 BACT Proposal in June 28, 2012 Permit Revision Application

Based on the results of the constant load source testing, Shell recognized that, despite substantial investment of time and money, the E-PODs were not able to reduce generator engine NOx emissions to achieve compliance with the Permit limits. Consequently, Shell

prepared a permit application to revise the emission limit based on the technical infeasibility of achieving 0.5 g/kW-hr. This section summarizes the June 28 request, while section 1.6 revises the June 28 proposal to request different emission limits, based on the experience with actual operation in 2012.

1.5.1 BACT for NOx Emission from Engines at Constant Load

In its 2010 application, Shell identified SCR as the most effective technology for controlling NOx emissions from reciprocating engines. Shell proposed to meet a 0.5 g/kW-hour NOx emission limit based on commitments by DEC Marine.[12] Shell did not propose an ammonia limit because ammonia is not a pollutant regulated by EPA and because DEC had not guaranteed an ammonia emission rate. The application discussed both oxidation catalysts and CDPF for PM control, but indicated CDPFs were not cost effective because of the small incremental reduction in annual mass emissions. As discussed above, however, the oxidation catalyst provided by DEC was not able to assure compliance with PM emission limits while simultaneously achieving the NOx emission limits.

Although the tests at NC Machinery, the tests of FD1 on the Discoverer, and tests of other generator engines at some loads indicate it is possible to meet the 0.5 g/kW-hr NOx emission limit, not all engine/E-POD combinations are able to meet this limit and none of the tests at either location simultaneously met NOx and NH3 emission limits. Although not all tests revealed compliance with the permit limit, a review of the BACT limits in Tables 1-2 and 1-3 confirm that the NOx emissions measured at NC Machinery and on the Discoverer are very low compared with typical permit limits. When one considers all the challenges Shell faced in designing and installing the control equipment on a leased ship, this is a noteworthy achievement.

In hindsight, our BACT analysis erred in Step 3 of the Top Down process by misunderstanding the effectiveness of SCR in controlling NOx when there are spatial restrictions to the size of the SCR while simultaneously meeting pressure drop limitations imposed by controls for other pollutants. Had we better understood the spatial and engine back pressure limitations, we would have proposed higher NOx limits. As discussed below, there are additional challenges that surfaced as the engines and E-PODs were operated during the 2012 drilling season.

While not required by guidelines on determining BACT, Shell spent millions of dollars and months of effort in engineering tests in the Philippines, Singapore, and in Tukwila that were essentially research and development studies. BACT is a case-by-case determination, and the

[12] As noted above, Shell proposed limits based on SCR even though it could have demonstrated that installing SCR units in these existing vessels would not be cost effective. Shell's commitments to North Slope communities included using the best control technology it could employ and there was no top-down BACT "cost-effectiveness" criterion built into that commitment. Shell, therefore, presented the use of those controls as BACT in its application. Shell acknowledges that EPA, in turn, processed Shell's proposals as BACT limits and will treat the requested revised limits as BACT. Shell believes that it is important, however, at least for precedent purposes, that the record reflect the uniqueness of Shell's application. Given the fact that Shell has spent in excess of $30 million getting to the point of being able to meet the requested revised limits, it is likely that those limits would be deemed well-beyond – that is, much more stringent than – BACT in other similar circumstances.

conclusion of Shell's efforts is that achieving 0.5 g NOx/kW-hr on a continuous long-term basis is not feasible on the D399 engines in this application.

To provide a basis for comparison, Table 1-2 presents the transitional Tier 4 emission limits for non-road engines, which do not apply to marine diesel engines. Table 1-2 also provides the emission limits imposed on large, stationary, non-emergency diesel engines in several recently-issued PSD permits and draft permits. Table 1-3 expands on Table 1-2 and provides details on the control devices and NOx emission limits determined to be BACT for those recently-issued PSD permits and draft permits. In most cases, EPA determined that engine design (e.g. use of turbochargers and aftercoolers) and good combustion practices constitute BACT.

Table 1-2 shows that the NOx emission limits of recently-issued PSD and draft permits are more than ten times less stringent that than the limit in the Discoverer's permit.

Table 1-4 provides a statistical assessment of the emission test results for the two E-POD designs applied to the D399 engines. To allow for the variation acknowledged by CleanAIR in its review of the test results (discussed above), Shell proposed in the June 2012 application a revised NOx BACT limit based on the mean of the low load tests (which have the highest emission factors but the lowest mass emissions) plus two standard deviations and a small margin for deterioration over time. For FD1, FD3, FD4, and FD5, the June 28 proposed NOx emission limit was 1.2 g/kW-hr. For FD2 and FD6, the June 28 proposed NOx emission limit was 2 g/kW-hr.

Table 1-2: Comparison of Current D399 Limits to Transitional Tier 4 Limits, and Similar Source Permit Limits

Source	Permit Issue Date	# Engines & Rated hp	NO_X g/kW-hr	PM g/kW-hr	CO g/kW-hr	VOC g/kW-hr	SO_2 ppmw S in fuel	NH_3 ppmv
Discoverer	9/19/2011	6 x 1,325	0.5	0.127[1]	0.179	0.23	15	5
Transitional Tier 4[15]	--	1,207 to 3,000	0.67	0.1	3.5	0.4	--	--
C.R. Luigs[2]	3/30/2012	8 x 5,875	18.1	0.24[1]	2.42	0.39	15	--
Development Driller 1[2]	3/30/2012	8 x 5,096	12.1	0.24[1]	1.98	0.39	15	--
Ocean Confidence[3]	2/29/2012	8 x 4,439	12.1	--	--	--	500	--
Deepwater Nautilus[4]	11/28/2011	4 x 4,929	12.7	--	--	--	500	--
Noble Bully (I and II)[4]	11/28/2011	8 x 4,027	5.5	--	--	--	500	--
Pathfinder[5]	10/27/2011	3 x 9,910 3 x 6,610	12.7	0.24[1]	3.3		15	--
DHPP[6]	7/14/2011	1 x 4,400	9.8	0.5[7]	--	--	--	--
Discoverer Spirit[8]	6/13/2011	4 x 9,910 2 x 6,610	12.7	--	--	--	500	--
Flopam[9]	4/26/2011	11 x 591, 6 x 1,175	6.4[10]	0.2[11]	3.5	--	--	--
BPXA[12]	6/15/2009	1 x 1,041	4.7	--	2.6	--	15	--
USAF - Eareckson[13]	9/29/2003	2 x 3,000 kW	1.46[14]		0.67			15[14]

1 PM, PM10, and PM2.5 emission limits are all the same.

2 The ultra-deepwater drillship C.R. Luigs and the semisubmersible drilling vessel Development Driller 1 are both included in a draft OCS permit issued for operations at multiple sites within the DeSoto Canyon lease block in the Gulf of Mexico. Draft Permit No. OCS-EPA-R4008, issued by USEPA Region 4.

3 The semisubmersible drilling vessel Ocean Confidence is in a draft OCS permit issued for operations within the Lloyd Ridge lease block 317 in the Gulf of Mexico. Draft Permit No. OCS-EPA-R4009, issued by USEPA Region 4.

4 The Deepwater Nautilus, Noble Bully I, and Noble Bully II are all included in an OCS permit issued for operations at multiple sites within the DeSoto Canyon and Lloyd Ridge lease blocks in the Gulf of Mexico. Permit No. OCS-EPA-R4006, issued by USEPA Region 4.

5 The drillship Pathfinder is in an OCS permit issued for operations within the Lloyd Ridge lease block 411 in the Gulf of Mexico. Permit No. OCS-EPA-R4007, issued by USEPA Region 4.

6 Permit No. AQ0215CPT03, issued to the Dutch Harbor Power Plant by Alaska Department of Environmental Conservation (ADEC).

7 Permit limit is on PM2.5 emissions.

8 The drillship Discoverer Spirit is in an OCS permit issued for operations within the Lloyd Ridge lease block 410 in the Gulf of Mexico. Permit No. OCS-EPA-R4005, issued by USEPA Region 4.

9 Permit No. PSD-LA-747(M1) issued by Louisiana Department of Environmental Quality (LDEQ).

10 Permit limit (which represents the lowest achievable emission rate – LAER) is on the combined emission rates of NOX and Non-Methane Hydrocarbons (NMHC).

11 Permit limit is on PM10 emissions.

12 Permit No. AQ0181CPT06, Rev. 2, issued to British Petroleum Exploration Alaska (BPXA) by ADEC.

13 Permit No. 307CP01, issued to US Air Force Eareckson Air Station, by ADEC.

14 This BACT determination (to use SCR) was reversed by their operating permit, which required using good combustion practices, no numerical limit in their permit.

15 Note that this emission standard applies to engines operating on a specific test cycle – not to engines operating in the field under highly variable conditions.

Table 1-3: Comparison of Current D399 Limit to Transitional Tier 4 Limits, and Other Relevant BACT Determinations

Source	Permit Issue Date	Emission Unit Description	Emission Unit	BACT Limit NOx g/kW-hr	NOx % Reduction	Vendor - Model	Control Device
Discoverer	9/19/2011	Drill rig power	FD-1-6	0.5	--	D. E. C. Marine, AB	SCR
Transitional Tier 4[15]	--	--	--	0.67	--	--	--
C.R. Luigs[1]	3/30/2012	Main power plant engines	EU-001 - 008	18.1	--	MAN B&W 9L32/40-47	Positive crankcase ventilation, turbocharger, high-pressure fuel injection with aftercooler
Development Driller 1[1]	3/30/2012	Main power plant engines	EU-001 - 008	12.1	--	Caterpillar 3612 DITA	Direct Injection, turbocharger/aftercooler
Ocean Confidence[2]	2/29/2012	Main propulsion generator	DR-GE-01 - 08	12.1	--	Wärtsilä F316A	Turbocharger/aftercooler, enhanced work practice power management and Nox emissions maintenance system. Good combustion and maintenance practices
Deepwater Nautilus[3]	11/28/2011	Drill rig generators	GEN-1 - 4	12.7	--	Wärtsilä 12V32 LNE	Low NOx Engine (LNE) design, turbocharger/aftercooler, injection timing retard, high injection pressure, and good combustion practices
Noble Bully (I and II)[3]	11/28/2011	Drill rig generators	GEN-1 - 8	5.5	--	Electro-Motive 20-710G7C-T2	Use of certified EPA Tier 2 engines with Low NOx Engine design (including ignition timing retard, turbo charger/after cooler, and high injection pressure), intake air cooling, and good

Table 1-3: Comparison of Current D399 Limit to Transitional Tier 4 Limits, and Other Relevant BACT Determinations

Source	Permit Issue Date	Emission Unit Description	Emission Unit	BACT Limit NOx g/kW-hr	NOx % Reduction	Vendor - Model	Control Device
							combustion practices
Pathfinder[4]	10/27/2011	Main propulsion diesel electric generators	DR-GE-01 - 6	12.7	--	Wärtsilä Vasa 18V32, 12V32 LNE	Low NOx Engine (LNE) design, turbocharger/aftercooler, injection timing retard, high injection pressure, and good combustion practices, enhanced with a Power Management System and NOx Concentration Maintenance System.
DHPP[5]	7/14/2011	Power plant	EU 15	9.8	35	Caterpillar C-280-16	Turbocharger/aftercooler
Discoverer Spirit[6]	6/13/2011	Workboat propulsion	DR-GE-01 - 06	12.7	--	Wärtsilä 18V32, 12V32 LNE	Low NOx Engine (LNE) design, turbocharger/aftercooler, injection timing retard, high injection pressure, and good combustion practices, enhanced with a Power Management and NOx Concentration Maintenance System.
Flopam[7]	4/26/2011	Chem plant under const.	Large Generator Engines	6.4[8]	--	None	None
BPXA[9]	6/15/2009	Oil/gas processing	EU IDS 49 - 56	4.7	15	--	Turbocharger/aftercooler, and good combustion practices
DHPP[10]	1/31/2007	Power plant	Unit 15	9.8	--	Caterpillar C-280	Turbocharger/aftercooler

Table 1-3: Comparison of Current D399 Limit to Transitional Tier 4 Limits, and Other Relevant BACT Determinations

Source	Permit Issue Date	Emission Unit Description	Emission Unit	BACT Limit NOx g/kW-hr	NOx % Reduction	Vendor - Model	Control Device
DHPP[10]	1/31/2007	Power plant	Unit 14	13.6	0	Wärtsilä 12V32C	Fuel injection timing retard and aftercooler
BPXA[11]	8/19/2005	Generator	Cummins IC Generator	--	--	Cummins	--
Nome Joint Utilities System[12]	11/5/2004	Generator	Diesel Electric Generator	134 (lb/hr)	--	WARTSILA 12V32B	Fuel injection timing retard (three gasses retard) and separate low temperature cooling water system/aftercooler
Westward Seafoods[13]	10/10/2003	Generator	IC Generator	8.65	--	Wartsila Model 6R32D	Water injection, low Nox design
USAF - Eareckson[14]	9/29/2003	Generator Engines	IC Engines units 5,6	--	--	Cooper Bessemer diesel engine	Good combustion practices

1 The ultra-deepwater drillship C.R. Luigs and the semisubmersible drilling vessel Development Driller 1 are both included in a draft OCS permit issued for operations at multiple sites within the DeSoto Canyon lease block in the Gulf of Mexico. Draft Permit No. OCS-EPA-R4008, issued by USEPA Region 4.

2 The semisubmersible drilling vessel Ocean Confidence is in a draft OCS permit issued for operations within the Lloyd Ridge lease block 317 in the Gulf of Mexico. Draft Permit No. OCS-EPA-R4009, issued by USEPA Region 4.

3 The Deepwater Nautilus, Noble Bully I, and Noble Bully II are all included in an OCS permit issued for operations at multiple sites within the DeSoto Canyon and Lloyd Ridge lease blocks in the Gulf of Mexico. Permit No. OCS-EPA-R4006, issued by USEPA Region 4.

4 The drillship Pathfinder is in an OCS permit issued for operations within the Lloyd Ridge lease block 411 in the Gulf of Mexico. Permit No. OCS-EPA-R4007, issued by USEPA Region 4.

5 Permit No. AQ0215CPT03, issued to the Dutch Harbor Power Plant by Alaska Department of Environmental Conservation (ADEC).

6 The drillship Discoverer Spirit is in an OCS permit issued for operations within the Lloyd Ridge lease block 410 in the Gulf of Mexico. Permit No. OCS-EPA-R4005, issued by USEPA Region 4.

7 Permit No. PSD-LA-747(M1) issued by Louisiana Department of Environmental Quality (LDEQ).

8 Permit limit (which represents the lowest achievable emission rate – LAER) is on the combined emission rates of NOX and Non-Methane Hydrocarbons (NMHC).

9 Permit No. AQ0181CPT06, Rev. 2, issued to British Petroleum Exploration Alaska (BPXA) by ADEC.

10 Permit No. AQ0215CPT02 Rev. 2, issued to Dutch Harbor Power Plant by ADEC

11 Permit No. AQ0417CPT05, Rev. 1, issued to British Petroleum Exploration Alaska (BPXA) by ADEC

12 Permit No. AQ0210TVP02P, issued to Nome Joint Utility System by ADEC

13 Permit No. AQ0433TVP02P, issued to Westward Seafoods, Inc. by ADEC

14 Permit No. 307CP01, issued to US Air Force Eareckson Air Station, by ADEC.

15. Note that this emission standard applies to engines operating on a specific test cycle – not to engines operating in the field under highly variable conditions.

Table 1-4: Analysis of NOx Emissions Testing							
NOx Emissions from E-POD 1345							
Load	**Max (g/kW-hr)**	**Mean (g/kW-hr)**	**Std. Dev. (g/kW-hr)**	**Mean + 1 Std. Dev. (g/kW-hr)**	**Mean + 2 Std. Dev. (g/kW-hr)**	**Max + 1 Std. Dev. (g/kW-hr)**	**Max + 2 Std. Dev. (g/kW-hr)**
Low	0.99	0.61	0.22	0.84	1.06	1.21	1.44
Medium	0.68	0.42	0.19	0.61	0.79	0.87	1.05
High	0.78	0.43	0.25	0.67	0.92	1.03	1.28
Composite	0.99	0.49	0.23	0.72	0.95	1.22	1.45
NOx Emissions from E-POD 26							
Load	**Max (g/kW-hr)**	**Mean (g/kW-hr)**	**Std. Dev. (g/kW-hr)**	**Mean + 1 Std. Dev. (g/kW-hr)**	**Mean + 2 Std. Dev. (g/kW-hr)**	**Max + 1 Std. Dev. (g/kW-hr)**	**Max + 2 Std. Dev. (g/kW-hr)**
Low	1.86	1.34	0.29	1.63	1.93	2.15	2.45
Medium	1.40	1.21	0.17	1.39	1.56	1.58	1.75
High	1.28	1.20	0.07	1.27	1.34	1.35	1.42
Composite	1.86	1.25	0.20	1.45	1.65	2.06	2.26

1.5.2 BACT for Ammonia Emissions

Ammonia (NH3) is not a federally regulated criteria pollutant, and is therefore not subject to BACT requirements under PSD review. An ammonia slip level of 10 ppmv was used in the Discoverer PSD permit application to estimate mass emissions of ammonia but this level was not intended to represent BACT. Indeed, no BACT analysis for ammonia was required. Shell is not aware of any ammonia limits in permits resulting from federal regulation.

There are permits that include ammonia limits but they are permits issued by states that have chosen to regulate ammonia, and are typically associated with ammonia slip from SCR units applied to combustion turbines and boilers. As indicated in Tables 1-2 and 1-3, Alaska Department of Environmental Conservation (ADEC) issued a permit in 2003 for two diesel-fired generator engines with a NOx limit of 1.46 g/kW-hr; this limit was to be achieved using an SCR system and an ammonia slip limit of 15 ppmv but the requirement to employ SCR was later reversed, and BACT was determined to be good combustion practices, with no numerical limit in their permit.

The ammonia limit that was imposed by EPA cannot be achieved while simultaneously achieving low NOx emissions. Given that EPA regulates NOx emissions and ambient NO2 concentrations, but regulates neither ammonia emissions nor ammonia ambient concentrations, Shell suggests that the focus of the permit should be on NOx emissions, not ammonia. In its permit applications, Shell identified anticipated ammonia emissions of 10 ppmv but did not propose an ammonia emission limit.

Furthermore, despite the placement of the ammonia limit in the BACT section of the permit, the permitting history indicates that an ammonia limit was originally intended to act as parametric monitoring for NOx. But in the permit's later iteration, periodic monitoring is required for NOx, making an NH3 limit unnecessary for confirming proper operation of the emission controls. The sequence of permit conditions related to ammonia follows:

- In 2009, the proposed permit included an NH3 BACT limit of 5 ppmv and NH3 monitoring requirements at each SCR. The Statement of Basis (SOB) for 2009 permit provides documentation on pages 47-48 that NH3 was to represent good performance of the SCR and oxidation catalyst system. Emissions of NH3, ammonia slip, can occur when the catalyst temperature is not in the optimum range for the reaction between NOx and ammonia. In order to ensure that the ammonia slip is maintained at the minimum level commensurate with achieving the NOx emission limit of 0.5 g/kW-hr, EPA proposed an emission limit for ammonia as part of the BACT emission limit for NOx from the generator engines. However, ammonia is not a federally regulated criteria pollutant and therefore should not be subject to a BACT limit.
- In 2010 reissuance of the permit and supplemental SOB, the permit removed the NH3 monitoring requirement but retained the NH3 emission limit of 5 ppmv. On Page 5 of the 2010 permit SOB, EPA states that the monitoring was changed to one-time stack testing and EPA made a conscious decision to remove ongoing monitoring.
- In 2011, additional on-going parametric monitoring requirements were added to the permit to ensure continuing performance of the SCR and oxidation catalyst systems. The 2011

permit requires monitoring and recording of the inlet temperature and urea flow. To ensure each catalyst is still active, the permit requires weekly measurements of NOx and CO concentrations downstream of the SCR and oxygen catalyst units with a portable monitoring device. At this time, it appears that EPA should have removed the NH3 limit because the additional parametric monitoring requirements adequately confirm proper operation of the SCR systems.

Shell proposed in June 2012 that EPA rescind the ammonia emission limit, and reaffirms that request in this application.

We can estimate potential NH3 mass emissions without the 5 ppm permit limit using worst-case emissions assumptions, with consideration given to operating restrictions that apply to the Discoverer generators. The Discoverer is limited to 120 days of drilling, and aggregate electrical generation is limited to 3,872 kWe. To provide conservative emissions estimates, we can apply the test results for 100 percent load, which almost always resulted in the highest emission factor when expressed as grams per kilowatt hour (g/kWe-hr).

Because the six engines can physically generate more than 3,872 kWe, we can assume that power generation duty is evenly distributed among the engines with the longer E-PODs (those with lower NOx emissions) and the remaining allowable power generation is assigned to FD-2.

Table 1-5 identifies annual NH3 emissions of 1.8 tons based on 24 hours of operation at full load (except FD-2 and FD-6) for 120 days per drill season.

Table 1-5: Potential Ammonia Emissions From Discoverer Generator Engines

Unit	Source Test	Load	Mass Emissions		
	lb/kWe-hr	kWe	lb/hr	lb/day	tpy
FD-1	9.00E-04	800	0.72	17.3	1.04
FD-2	6.37E-05	672	0.04	1.0	0.06
FD-3	2.51E-04	800	0.20	4.8	0.29
FD-4	1.95E-04	800	0.16	3.7	0.22
FD-5	1.58E-04	800	0.13	3.0	0.18
FD-6	1.08E-04	0	0.00	0.0	0.00
Total		3,872	1.25	29.9	1.8
Permit Power Output Limit:		3,872			

1.5.3 Administrative Order on Consent

When the Discoverer first became an OCS Source, on September 6, 2012, Shell submitted an excess emissions report to EPA as required under Permit Condition A.15.2 to formally acknowledge what source testing had already demonstrated and Shell's June 28 revision application had addressed: that emission units FD-2 through FD-6 were unable to meet the 0.5 g/kW-hr BACT NOx limit and therefore were also assumed to be unable to meet the aggregate hourly mass emission limit. On September 7, EPA and Shell entered into an Administrative Compliance Order on Consent. Acknowledging the data provided in Shell's June revision application and the fact that a permit revision would not be processed in time to accommodate

the 2012 season, the Order required Shell's operations to meet the revised limits proposed in the June 28 revision application and imposed additional monitoring, recordkeeping, and recordkeeping obligations. As discussed below, while the limits imposed by the Order were appropriate for operation of the engines in the manner operated during source testing, Shell discovered during the recent operating experience that the limits are not feasible for the variable loads inherent during exploratory drilling operations.

1.6 Revise NOx Emission Limits to Accommodate Operational Realities

Shell believes the revised NOx emission limits proposed in the June 28 application and incorporated into the September Order are still appropriate for constant load conditions, but 2012 operating experience as an OCS source shows that constant load conditions are not the norm for the engines during drilling operations. As a result, the engines cannot consistently meet the proposed NOx emission limits in actual operation. Although there may be times when an engine operates at a steady load for more than 10 minutes such that the BACT limits are achieved, the 2012 operating experience proved that the engines powering the generators will necessarily operate at variable loads as drill rig electrical demands fluctuate. This section describes the 2012 operating experience and proposes a revised BACT emission limit for NOx emissions from the main generators.

1.6.1 Issues with E-POD Controls in 2012

The six E-POD systems installed Discoverer main generators were custom designed by CleanAIR, a subsidiary of Caterpillar, for control of NOx, PM, CO, and VOC. E-PODs were also designed and fitted on four generators on the Kulluk drillship and on eight large engines on the Aiviq, a new ice management vessel constructed by Shell. Unlike the E-PODs on the Kulluk and Aiviq, the E-PODs on the Discoverer have proven problematic since installation in May, 2012, resulting in Shell having to report excess emissions and permit deviations. Shell, Caterpillar, CleanAIR, and Noble have invested significant time, money, and resources to correct deficiencies in these units. The technical team identified the major deficiencies and applied mitigating measures in an effort to meet the 2012 permit requirements. The team is now working on further enhancements to improve performance in 2013.

Soon after deployment in 2012, the technical team identified several problems with E-POD operation:

1. These engines were designed in the 1960s and manufactured in the 1970s. Unlike the new generator engines on the Kulluk and all the engines on the Aiviq, the Discoverer generator engines do not have electronic controls that provide important engine operating information to the E-POD controller software. As discussed further below, the controller software is not currently responding quickly enough to changes in engine operating conditions.

2. The Caterpillar D399 engines are de-rated from a nominal 850 kW to 800 kW to meet marine Class (ABS) requirements for continuous service. Furthermore, due to concerns of accidental overload of the electrical system on the drill ship, the generators are typically operated at modest levels. A warning light illuminates on the driller's console when a generator power level exceeds 600 kW. At that point, the rig foreman would

typically call for more generators to be placed on line, so generators tended to operate in the 300-550 kW range resulting in exhaust temperatures barely exceeding the 300° C level. Thus, the typical exhaust temperature of these engines in 2012 was not as high as more recent vintage engines or similar engines installed for land applications.

3. The load applied to engines is more variable than experienced by typical land based installations. Land based installations have tended to be pumping and generation applications, which are relatively constant load. The ship-board installations tend to be quite variable, and the closed loop control built into the E-POD software can lose control from rapidly varying loads. When the E-POD closed loop system determines it has lost control, it goes through a 10 minute purge cycle, reverts to an open loop control map, and begins anew at a 70% NOx reduction target before slowly climbing back to its target of approximately 90% NOx reduction. Small adjustments in urea feed rates are made every 40 seconds, so it can take tens of minutes to achieve high levels of NOx reduction.

4. The air flow around the urea injection lance was not optimized. A standard E-POD system channels exhaust from the CDPF filters into a narrow chamber where the urea is injected. The urea then flows through mixing chambers that enable thorough mixing and disassociation into water vapor and NH_4. Because of space constraints in the Discoverer, the E-PODs had to be designed without a narrow mixing chamber that would increase exhaust flow. Urea in the Discoverer E-PODs is injected directly into a relatively large volume where air flow velocity around the lance is relatively low. During the 2012 season this low air flow at times resulted in a rapid build-up of urea crystals beginning at the base of the nozzle. It has been determined that when temperatures remain below ~350° C in the mixing chamber for extended periods of time, the crystalline structure grows until it completely encases the lance. Figure 1-1 is a September 30, 2012 photograph of large crystalline growth that occurred in the FD-4 E-POD.

5. Each E-POD is designed to have its own compression unit to chill the air to remove water prior to use in the urea injection lances. In an effort to provide redundancy, Shell connected the six compressors to a common header that fed each of the E-POD units. The objective was to ensure compressed was air available to all E-PODs in the event one compressor failed. There were problems in the original installation that caused these systems to generate excessive amounts of water; the water rusted the plain carbon steel header, which in turn clogged filters in the E-POD units. The net result was insufficient compressed air into the urea injection lances. This was the first problem identified in mid-August when the Discoverer was in Dutch Harbor. Caterpillar and Noble corrected the issues associated with the compressed air and it was believed that the urea crystalline formation issue was solved. At the end of September, however, it became evident that even with good compressed air flowing into the lances, urea crystalline formation was still occurring in all six E-POD units.

Figure 1-1: Urea Crystallization within the FD-4 E-POD

1.6.2 Excess Emissions and Permit Deviations

Although the E-PODS were purchased, designed, and installed to achieve approximately 90 percent NOx control, operational experience during the 2012 drilling season has shown that the systems were not able to continuously achieve that level of control, resulting in Shell having to report some corresponding excess emissions and permit deviations to EPA.

Permit Condition A.15 directs Shell to report all emissions or operations that exceed or deviate from Permit requirements. This condition requires Shell to submit two types of reports: excess emissions reports and permit deviation reports. Excess emission reports must be submitted "within two working days after the event commenced or was discovered" for malfunctions that cause emissions in excess of a technology-based emission standard, any other exceedance of an emission limit, or any exceedance of a throughput limit. Permit deviation reports must be submitted within 30 days after the end of the month during which the deviation occurred, and are required for all other excess emissions and permit deviations. The need to report excess emissions within two days of the occurrence means that those reports address individual events. Permit deviation reports, on the other hand, span a month of operation and therefore contain various types of permit deviations that might occur on different vessels. In addition to some two-day excess emission reports, Shell submitted a 30 day permit deviation report for September operations on November 2, 2012, and is in the process of finalizing the 30 day

permit deviation report for October 2012 operations (October permit deviations are nonetheless included in the excess emission and permit deviation data described in this application). As discussed further in Chapter 6, most of the excess emission and permit deviation reports resulted from start-up periods.

The Permit requires Shell to demonstrate compliance with emissions and technology-based limits for the main generator engines. As discussed further in Chapter 2, the Permit requires Shell to monitor inlet parameters at 15-minute intervals and to take weekly measurements of outlet NOx concentrations to demonstrate proper operation of catalytic control devices installed on the Discoverer and Associated Fleet. Permit Conditions B.14.7 and B.15.7 require Shell to submit deviation reports for periods when certain control device parameters are outside of established thresholds. Deviations such as these do not always cause an exceedance of an emission limit; therefore, two-day excess emission reports are not necessarily required as a result of every such permit deviation.

Excess emission and permit deviation reports submitted due to operation of the Discoverer main generator engines, apart from start-up events, which are discussed in Chapter 6, are presented in Table 1-6

Table 1-6: 2012 Excess Emission & Permit Deviation Reports, Units FD-1-FD-6

Report Type	Unit/Units	Date of Excess Emission or Deviation	Basis
Excess Emission	FD-2 – FD-6	9/6/2012	Source testing
Excess Emission	FD-1 - FD-6	9/22/2012	Appearance that urea was not flowing to the FD-2 E-POD, resulting in using uncontrolled emission factors to calculate hourly NOx emissions
Excess Emission	FD-1 - FD-6	9/23/2012	Weekly performance check indicating that FD-1 through FD-6 E-PODs were not achieving optimum NOx control efficiency, resulting in using uncontrolled emission factors to calculate hourly NOx emissions
Permit Deviation	Multiple	9/6-9/30/12	Various
Permit Deviation*	Multiple	10/1-10/31/12	Various

*Permit deviation report is in progress and has not yet been submitted to EPA

These reports were generally for periods when EPODs were operating (i.e. not during start-up) but the emission control inlet exhaust temperature was below the minimum threshold (for periods of 15 minutes); the urea pump was not operating (for periods of 15 minutes); the weekly measured NOx concentration exceeded specified concentrations; or the weekly measured CO concentration exceeded specified concentrations. Two excess emissions reports and approximately 24 percent of the total permit deviations reported for the Discoverer and

Associated Fleet were attributable to the issues discussed in Section 1.6.1 affecting the E-PODs installed on Units FD-1 through FD-6. Yet, continuous monitoring data from the E-POD systems shows that 15-min deviations attributable to the issues discussed in Section 1.6.1 only occurred during 1.8 percent of the total time that the Discoverer main generator engines operated over the course of the 2012 season. Furthermore, to the extent that urea crystalline formations resulted in excess emission or deviation reports, use of uncontrolled emission factors to calculate hourly NOx emissions may not have been reflective of actual emissions, as measurements indicated that the crystalline formations within the E-PODs were emitting ammonia, providing some level of NOx control even when urea was not flowing to the device.

1.6.3 Efforts to Achieve PSD Permit Limits

Caterpillar, Noble, and Shell responded to problems experienced with the E-PODs as follows:

1. Initial problems with the air compressor units were corrected and compressors units were placed on a strict maintenance program.

2. Replaceable air filters were installed on compressed air lines upstream of each E-POD control cabinet to capture rust in the lines.

3. Crews were trained to operate generators at rates higher than was the previous practice. Instead of starting an additional generator when the power warning light illuminates on the driller's console, the crew monitors kW readings and makes an effort to keep power levels above 500 kW on each generator. This resulted in higher average power levels and exhaust temperatures averaging about 30° C higher since early October when new guidance went into effect. Figure 1-2 illustrates the results of this revised procedure on average power output from FD-1.

4. Exhaust temperature display monitors were added in the 1st Engineer's and Chief Engineer's office with color coded warnings to help crew better operate engines at higher exhaust temperatures.

5. A full-time trained E-POD technician from Caterpillar service organization was added to the Discoverer crew.

6. Urea injection lances are removed and cleaned at short intervals to ensure urea crystals are not building up inside of each cabinet, although the steps taken to achieve higher operating temperatures resulted in significantly less crystalline formation than seen earlier in the season.

As a result of these measures, continuous monitoring data from E-PODs installed on FD-1 through FD-6 showed that 15-min deviations attributable to the issues discussed in Section 1.6.1 decreased from 3.5 percent in September to 1.1 percent in October, of the total time that the main generator engines operated in each month.

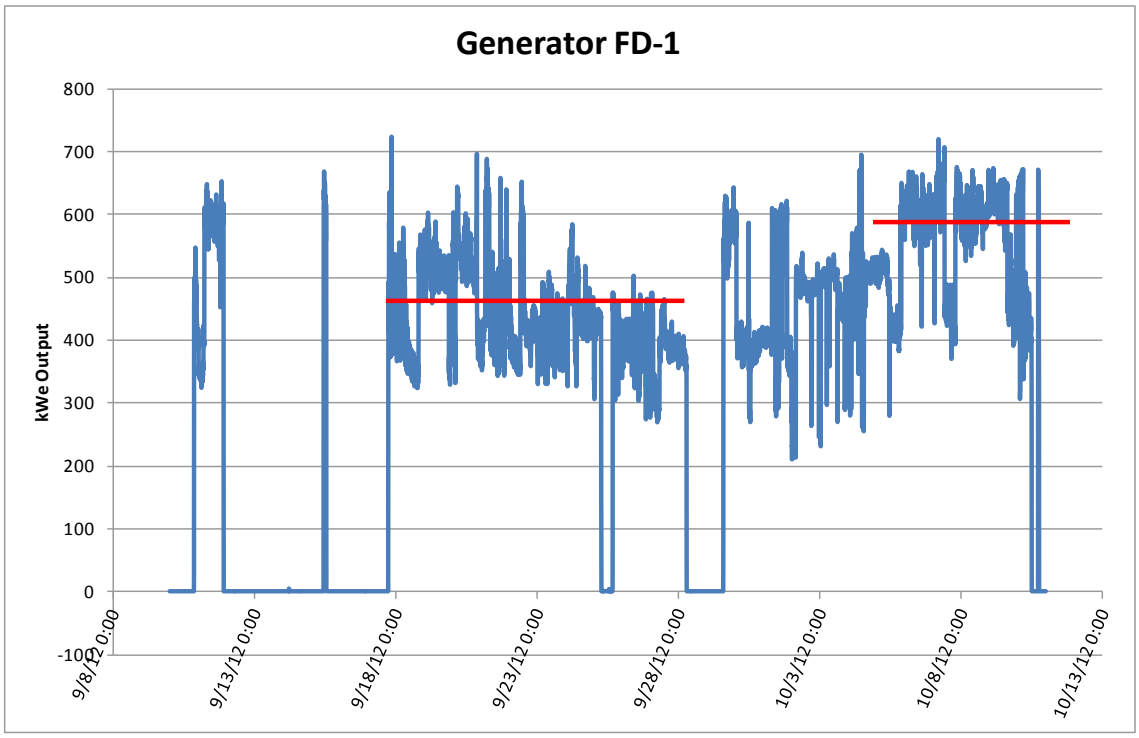
The effort to improve E-POD performance is continuing even after the 2012 drilling season has ended:

1. Caterpillar CleanAIR hired a “urea crystalline formation” expert to help resolve the formation problem. Two recommendations are under consideration. One is to reduce the flow of compressed air into the lance so that temperature of urea spray is higher. The second is to redesign the interior of the E-POD boxes to increase air flow at the lance tip.

2. CleanAIR is having a newly designed exhaust heat element manufactured that will be installed upstream of CDPF filters in each E-POD. These heat elements will turn on when exhaust temperatures are below 350°C.

3. CleanAIR is developing an entirely new algorithm to control urea injection. CleanAIR is considering more of an open loop design with small, limited adjustments from a closed control loop. The current design employs an open loop design to 70% reduction and then switches to a closed loop algorithm to achieve higher levels of reduction. The problem with this approach is that it does not respond well to rapidly varying load levels and often loses control. This new algorithm may be used experimentally in one or more units on the Discoverer in 2013.

Figure 1-2: Increase in FD-1 Average Generating Rate



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18

1.6.4 Proposed BACT Limit for NOx Emissions

As discussed above, significant efforts have been made, and continue to be made, to improve E-POD performance. Nonetheless, there is no experience with similar situations on other projects that Caterpillar or Shell can rely on to confirm that these efforts will completely resolve the problems experienced in 2012. Although Shell believes it will resolve the urea crystallization and exhaust temperature challenges before the 2013 season, Shell and its contractor are still working to improve E-POD response to variable engine load. Shell needs more data from actual operations to optimize that system and determine what emission rate is technically feasible to consistently achieve on a long-term basis.

We now know that Step 3 of the Top Down BACT analysis in our June 28, 2012 revision application did not take into account the “real world” effectiveness of SCR in controlling NOx when engine load is highly variable. Shell proposes to revise the BACT limit for NOx emissions from the generator engines to reflect what was achievable in the 2012 season during periods when crystallization was not reducing the effectiveness of the E-PODs.

Lacking Continuous Emissions Monitoring Systems (CEMS) data, however, the best available information is from the NOx sensors employed by the E-POD controller.[13] There are sensors upstream and downstream of the SCR that identify NOx concentration (ppm) in five-minute averages.[14] To better reflect anticipated operating conditions in 2013, these data were collected for periods when crystallization was believed to be nonexistent or minimal. Data were also screened to include only entries where (1) engine power was greater than 10 kW and (2) the inlet and outlet NOx concentrations were reported at greater than zero. This screening was an effort to ensure that only data for functioning engines and sensors were evaluated. Finally, rolling 24-hour average emissions were calculated only if at least 75% of the 288 5-minute values were present; this ensured that the graphs were not distorted by periods when there were few data entries. The actual number of data points varies from engine to engine depending on how many hours each engine was operated in 2012, but there were between 2,000 and 8,000 data points for each engine after filtering.

The concentration data were used to prepare graphs of generator engine emissions (expressed as g/kW-hr). To calculate mass emissions, it was necessary to first calculate exhaust volumetric flow rate for each observation. Exhaust flow was determined by using a linear regression of engine load verses exhaust flow from data collected for each engine during the compliance source tests. Mass emissions were then divided by simultaneous generator power output to obtain g/kW-hr for each data point.

The graphs below present 5 minute data, rolling hourly averages of the five minute data, and rolling 24-hour averages of the five minute data (Figures 1-3 through 1-8). Each curve identifies the fraction of time the observed emission rate (in g/kW-hr) was less than a certain value. For example, the 24-hour block average emission rate for FD-1 was less than 2 g/kW-hr almost 90 percent of the time and less than 3 g/kW-hr about 98 percent of the time.

13 The sensors are used to identify the relative outlet/inlet concentrations to guide urea injection rates. The absolute accuracy of the sensors is estimated by CleanAIR to be +/- 20 percent, but comparisons with Testo analyzer readings in 2012 indicated the sensors were generally within 10%. Shell developed sufficient confidence in the E-POD NOx sensors to use these data to develop propose BACT limits for actual operation.

14 Although periodic measurements with portable Testo 350 gas analyzers are also available, there are relatively few observations compared with thousands of NOx concentrations observations from the E-POD sensors.

Figure 1-3: FD-1 NOx Emissions Cumulative Frequency Plot

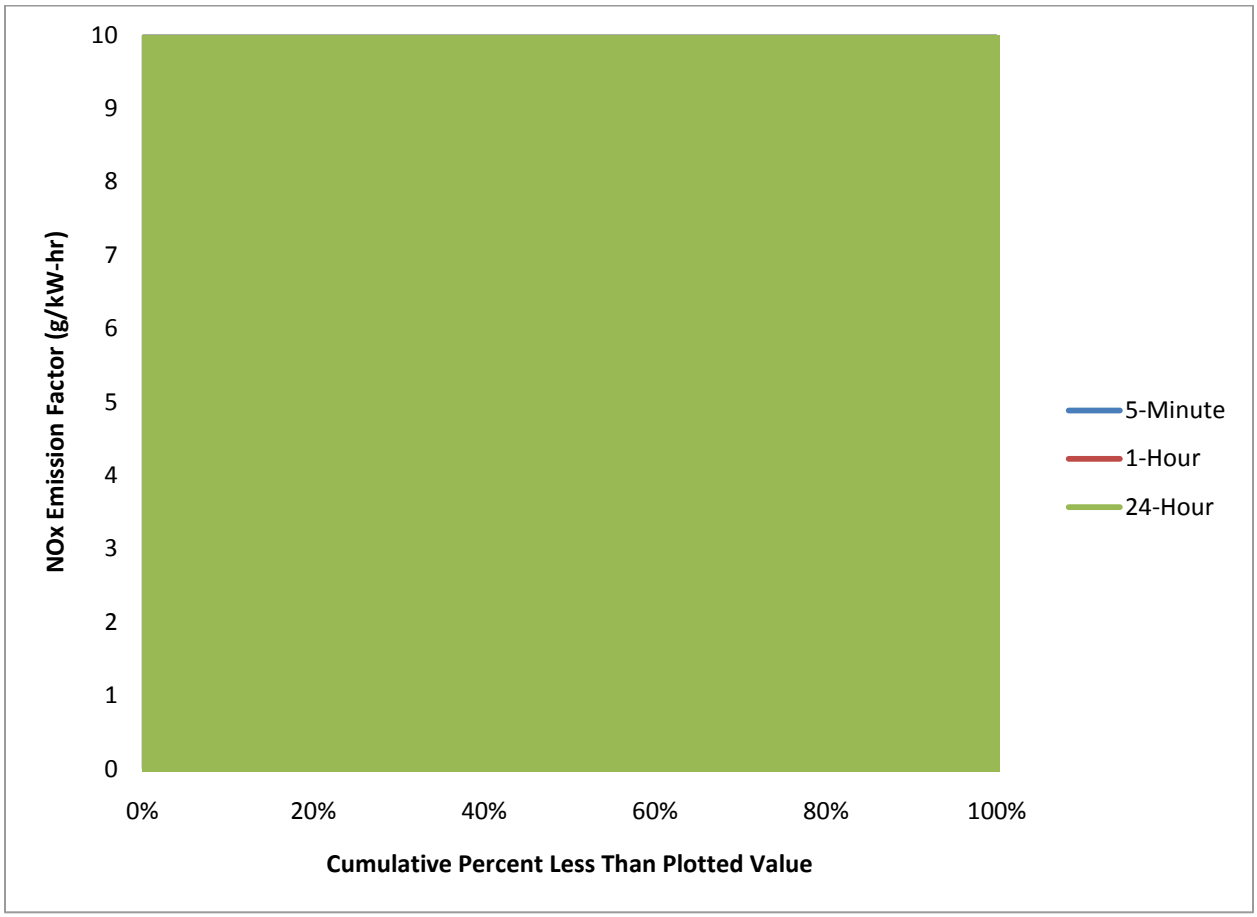


Figure 1-4: FD-2 NOx Emissions Cumulative Frequency Plot

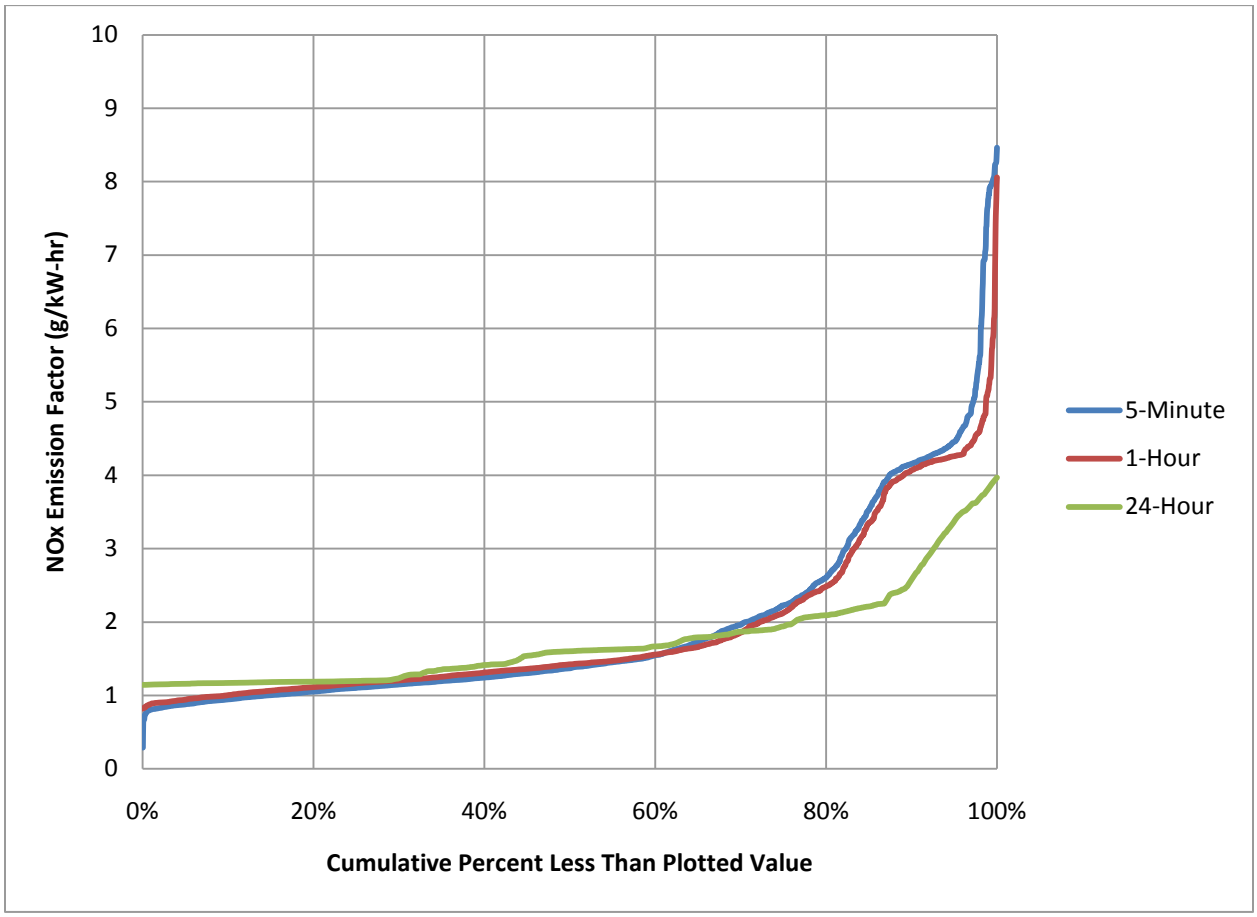


Figure 1-5: FD-3 NOx Emissions Cumulative Frequency Plot

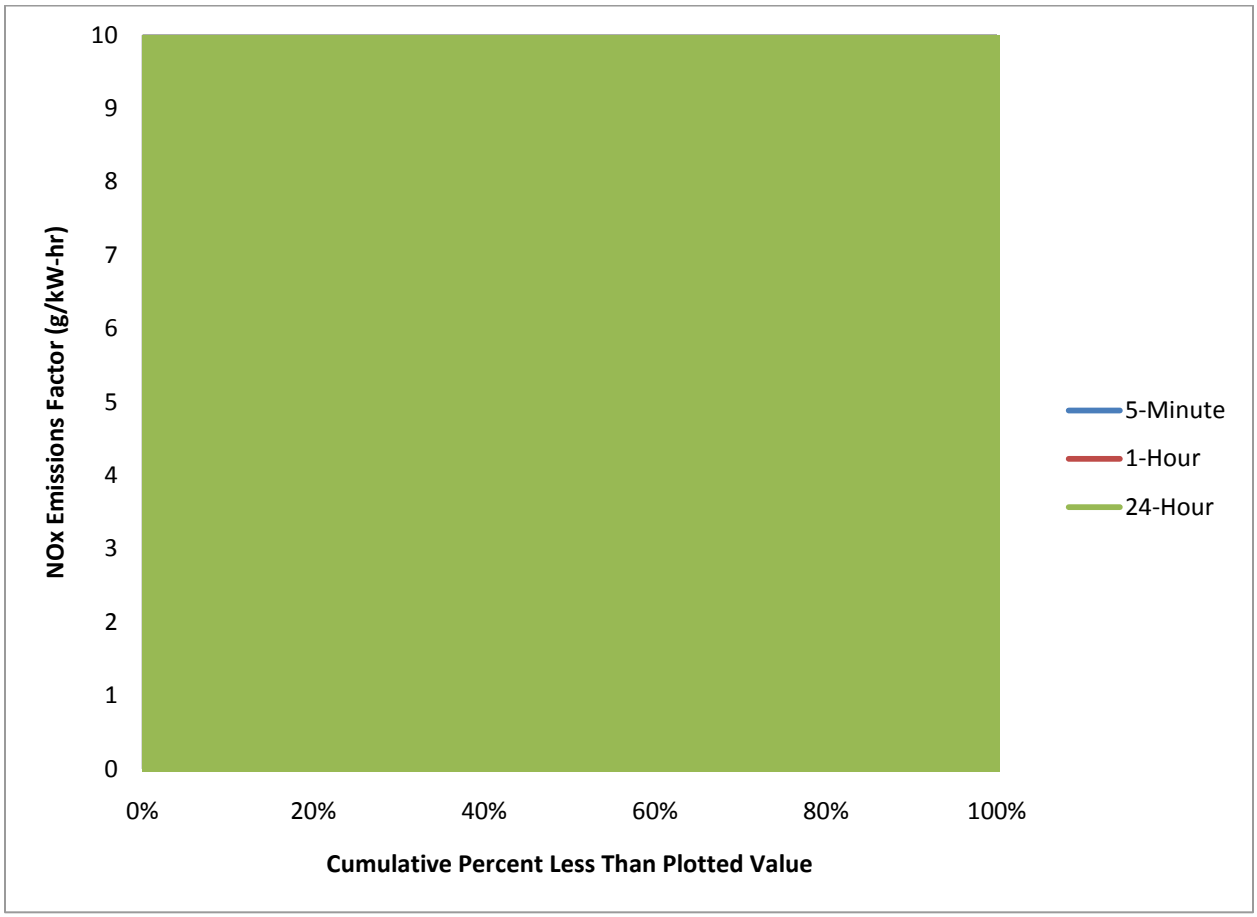


Figure 1-6: FD-4 NOx Emissions Cumulative Frequency Plot

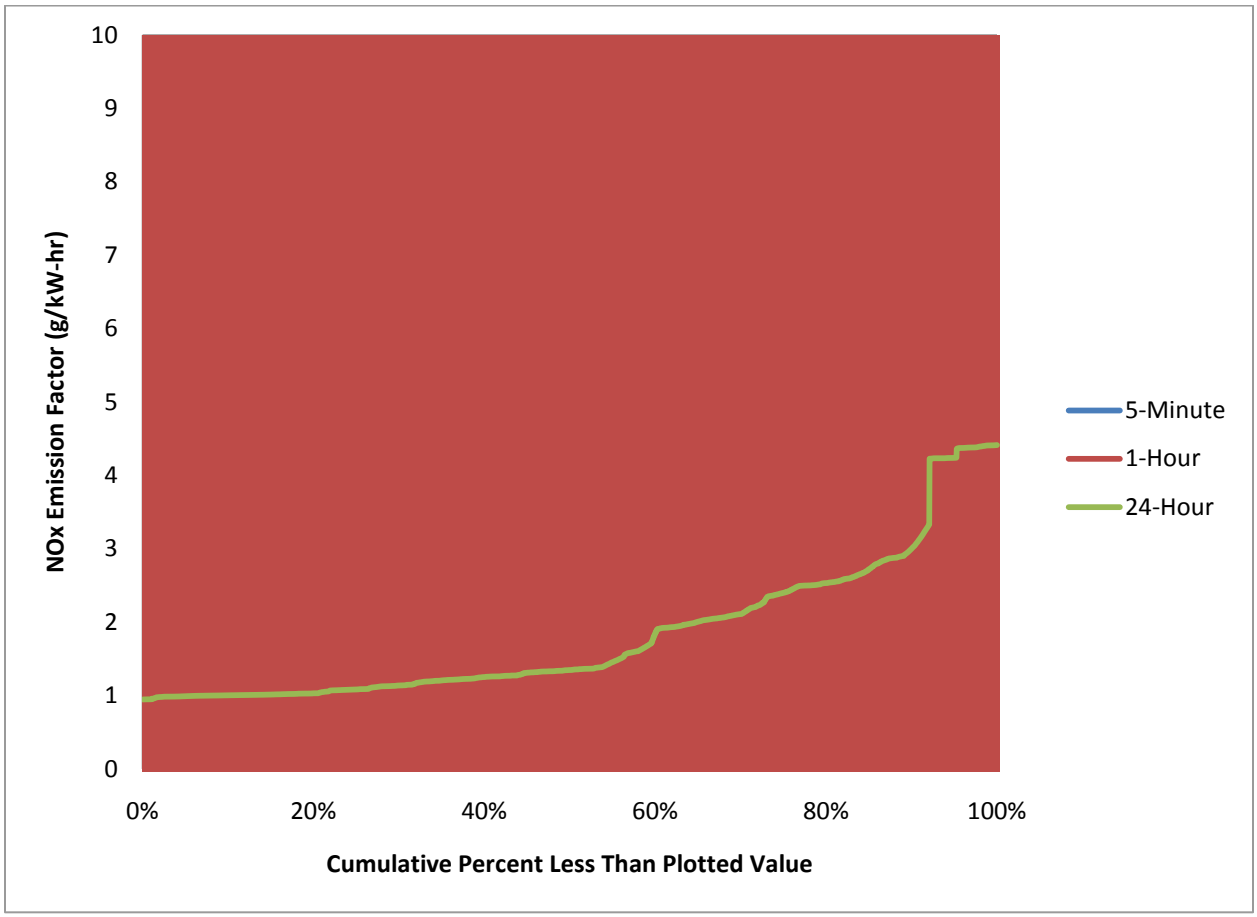


Figure 1-7: FD-5 NOx Emissions Cumulative Frequency Plot

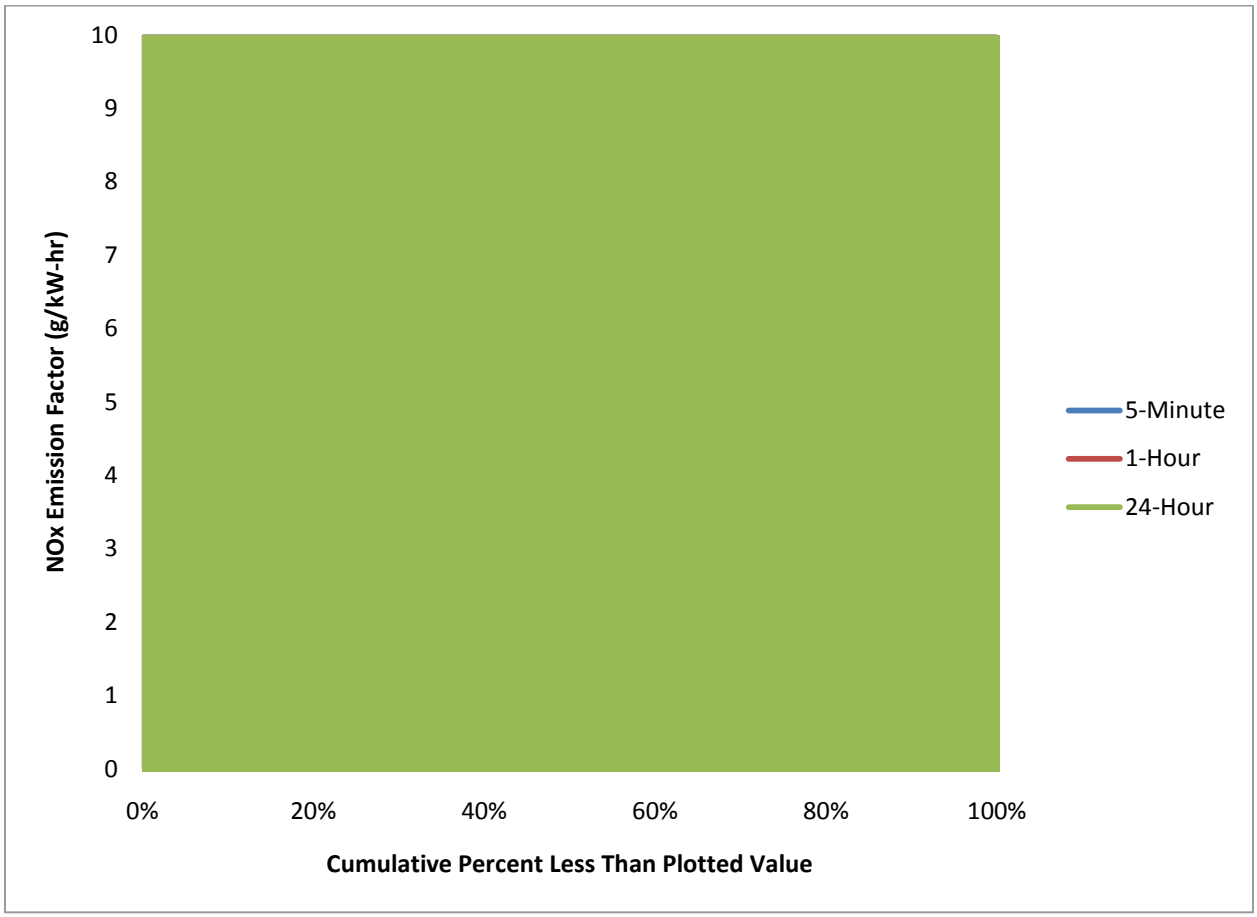
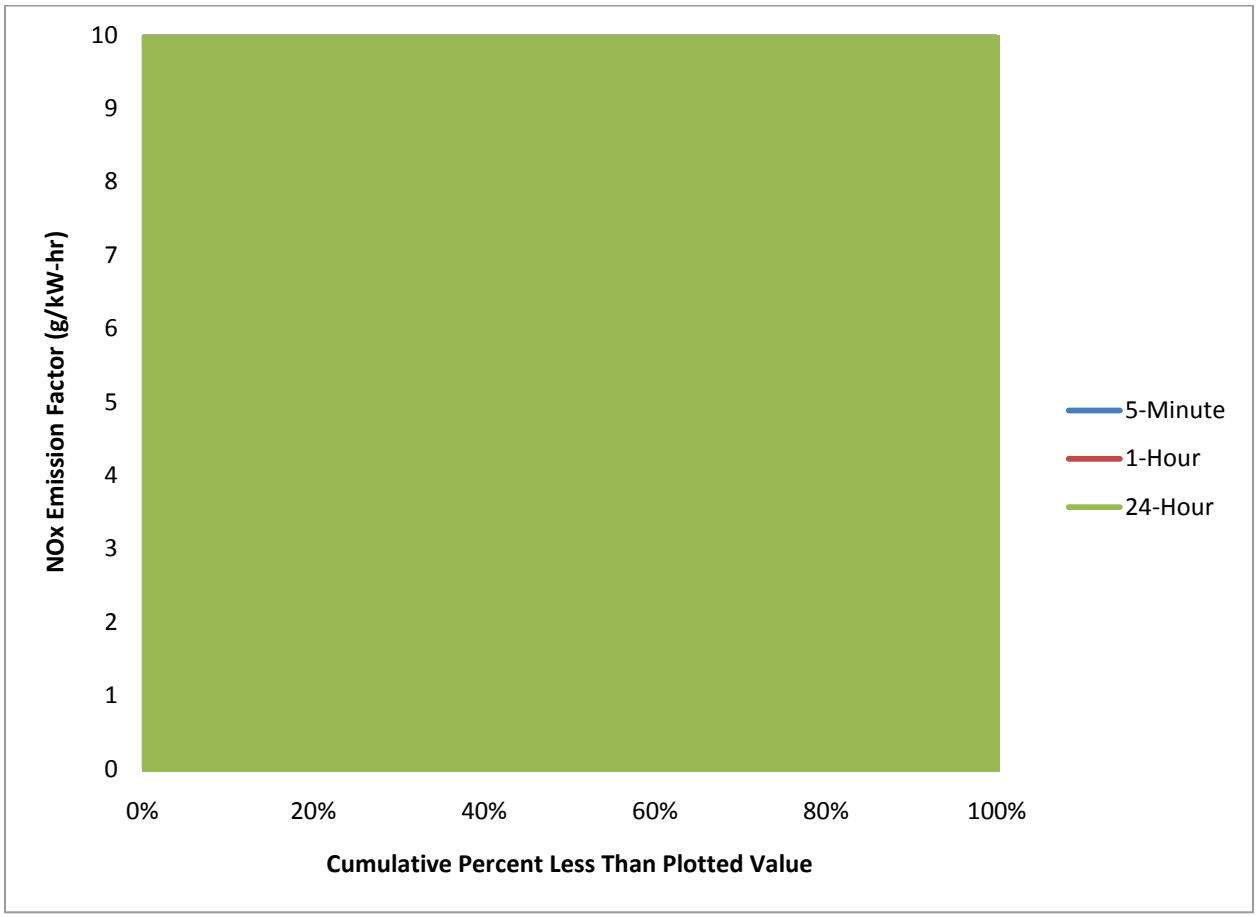


Figure 1-8: FD-6 NOx Emissions Cumulative Frequency Plot



Evaluation of Figures 1-3 through 1-8 shows that 24-hour rolling average emissions are approximately 1.5 g/kW-hr more than half the time, less than 2 g/kW-hr approximately 75 percent of the time, and less than 3 g/kW-hr approximately 90 percent of the time. There is more variability in the curves on the relatively infrequent occasions when emissions exceed 3 g/kW-hr. If BACT emission limits were based on a robust statistical form (such as recent ambient standards) that allowed for occasional exceedances of a given value, the BACT limit could be much lower than a form that cannot ever be exceeded. Given today's practice of "not to exceed" emission limits, the 2012 emissions data compel Shell to request a high BACT emission limit compared with the existing limit and the limit that can be easily achieved most of the time. Shell proposes that design, installation, and proper operation of E-POD control technology and an emission limit of 6 g/kW-hr, averaged over 24 hours, is BACT for the Discoverer generator engines. Shell believes the 24-hour average is appropriate because engine load and NOx output is highly variable and the E-POD response times are currently relatively long (on the order of 10 minutes). Furthermore, the modeling analysis demonstrates compliance with the 1-hour NO2 limit even if emissions at 6 g/kW-hr are assumed for hourly mass emissions.

Table 1-7 identifies the mass emissions of NOx authorized by the current permit (0.5 g/kW-hr) and the NOx emissions that would result if the BACT limit is increased to 6 g/kW-hr. Table 1-7 indicates the increases in annual potential emissions would be 64.2 tons. However, as

discussed above, NOx emissions above 3 g/kW-hr occurred only about 10 percent of time (or less). Examining Figures 1-3 through 1-8 indicates average NOx emission rates are less than 3 g/kW-hr. As indicated in Table 1-7, NOx emissions of 3 g/kW-hr correspond to annual aggregate mass emission of 35 tons. Shell proposes to limit the increase in NOx emissions to 39 tons.

Table 1-7: Generator Engine NOx Mass Emissions

BACT Limit	Emissions per Engine		Emissions all 6 Engines	
g/kW-hr	lb/hr	tons/year	lb/hr	tons/year
0.5	0.77	0.97	4.64	5.8
6.0	9.29	11.66	55.72	70.0
3.0	4.64	5.83	27.86	35.0
Proposed Annual NOx increase:				39

1.6.5 Compliance Monitoring

Shell proposes to monitor NOx emissions during the 2013 drilling season with an improved monitoring system. Shell's proposal results from examination of the 2012 permit that EPA Region 4 issued to Shell for exploration drilling in the Gulf of Mexico (permit no. OCS-EPA-R4006). That permit requires Shell to monitor compliance with a main generator engine NOx emissions limit of 12.7 g/kW-hr (24-hour average) using either:

- an EPA-approved continuous emissions monitoring system; or
- an EPA-approved alternative parametric monitoring method; or
- a stack testing emissions monitoring system (with prior written approval from EPA).

In this case, implementation of the CEMS option did not subject Shell to the rigorous NSPS requirements governing CEMS operation at shore-side facilities but did require EPA approval of the CEMS plan and a quality assurance plan for the certification and operation of the CEMS. The improved monitoring system Shell proposes would serve four purposes:

- monitoring compliance with the proposed emission limits;
- assist in diagnosing and refining operation of the engines and E-PODs to minimize NOx emissions;
- provide actual emissions information during startup and when low temperatures or urea flow issues would otherwise require use of an uncontrolled emission factor; and
- gather additional information that can be used to reassess the appropriate BACT limit for the generator engines for application in 2014 and subsequent seasons.

Three options for the improved monitoring system are under consideration.

Predictive Emissions Monitoring System (PEMS). Shell requested and received a proposal from CMC Solutions for a parametric monitoring system that relies on engine operational data and relationships developed from source testing to predict emissions.

Laser Emissions Monitoring Technology. Laser technology is currently available and in use on ships to monitor NOx emissions as required by MARPOL Annex VI Regulation 13 of the Maritime Emissions Regulations.[15] The sensor is a quantum cascade laser (QCL) and is capable of quantifying concentration of both NO and NO2 (including in-stack moisture).

Continuous Emissions Monitoring System (CEMS). Shell would install and operate one or more conventional NOx analyzers to "continuously" monitor NOx. In the interest of space, Shell may use one or two analyzers and stream switching to monitor all six stacks.

Shell proposes to further investigate the feasibility, reliability, and accuracy of each of these options in the next few months. Regardless of the technology selected, Shell would submit for EPA approval a monitoring proposal and implement that monitoring system prior to the 2013 drill season.

The enhanced monitoring system would replace the current use of portable analyzers, which provide only periodic data. After selecting and implementing an enhanced monitoring system for the generator engines, Shell proposes to end periodic monitoring of the engine exhaust using portable exhaust gas analyzers

1.6.6 Proposed Revisions to Permit Conditions

BACT is defined in the PSD rules (40 C.F.R. §52.21(b)(12)) in part as:

> *an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant*.

The preceding sections have documented the unique circumstances that affect Shell's ability to install and operate control equipment on the Discoverer D399 generator engines. These sections also document the extensive efforts Shell expended to achieve the current limits. Shell has determined that the existing NOx and NH3 limits are not technically feasible for this particular case, and requests that EPA revise the BACT limits for NOx and NH3 emissions from the D399 engines accordingly.

[15] Revised MARPOL 73/78 Annex VI Regulation 13 – Nitrogen Oxides (NOX) - NOX Technical Code 2008, Chapter 6.4 – Procedures for demonstrating compliance with NOX Emissions
limits on board – 'Direct measurement and monitoring method (DMM)

The proposed NOx and NH3 emission limit revisions require three sections of the permit to be revised. The changes occur in Condition C.3, C.4, and C.5, as follows:

3. BACT Limits. Emissions from each generator engine (Units FD-1 – 6) shall not exceed the emission limits specified for each of the pollutants below:

3.1. Nitrogen oxides (NOX): ~~0.50~~ 6 grams (g) per kilowatt-hour (kW-hr), 24-hour average.

3.1.1. For compliance with Condition C.3.1, measurement of NOX shall be determined ~~using EPA Method 7E~~ as specified in Condition C.9.X.

~~3.2. Ammonia (NH3): 5 parts per million by volume (ppmv) at actual stack gas conditions~~

~~3.2.1. For compliance with Condition C.3.2, measurement of NH3 shall be determined using EPA Conditional Test Method 027 or 038.~~

4. Annual Emission Limits. Emissions from all six generator engines in aggregate (Units FD-1 – 6) shall not exceed the emission limits specified for each of the pollutants below:

4.1. Nitrogen oxides (NOX): ~~5.83~~ 44.83 tons/rolling 12-month period

4.1.1. For compliance with Condition C.4.1, measurement of NOX shall be determined ~~using EPA Method 7E7E~~ as specified in Condition C.9.X.

5. Hourly Emission Limit. Emissions from all six generation engines in aggregate (Units FD-1 –6) shall not exceed the emission limits specified for each of the pollutants below:

5.1. Nitrogen oxides (NOX): ~~4.64~~ 55.72 lb/hr

5.1.1. For compliance with Condition C.5.1, measurement of NOX shall be determined ~~using EPA Method 7E~~ as specified in Condition C.9.X.

Because Shell proposes to implement an enhanced NOx monitoring system, additional changes to the monitoring requirements in Condition C.9 are warranted. After conditions 9.1-9.3, which address requirements for monitoring and recording power output, we propose a new condition that requires monitoring of NOx emissions. NOx measurements from the enhanced monitoring system would be used to determine hourly and daily NOx mass emissions for routine emissions monitoring and recording. If the enhanced monitoring system were to malfunction, monitoring would fall back on the existing practice of estimating emissions using 2012 source test-based emission factors and power output.

Shell proposes to apply a source test based emission rate during periods of SCR malfunction in lieu of the current assumption of 20 times the controlled emission rate.

New 9.X: Submit for EPA approval a plan to install and commission an enhanced system to monitor NOx emissions from the generator engines prior to the 2013 drill season. This monitoring system must be capable of monitoring actual NOx emissions from each generator engine on an hourly basis. The plan must include a mechanism to calculate mass emissions and enable determination of NOx emissions on a g/kW-hr and lb/hr basis.

9.4. Each month, calculate and record NOx emissions in g/kW-hr from each engine for each hour during the month, using the enhanced monitoring system under Condition 9.X. In the event that the enhanced monitoring system is not operational, calculate hourly NOx emissions using the emission factors collected under Condition C.8.5, and power output data collected under Condition C.9.3, and converted to kW (mechanical).

9.5. Each day, calculate and record for the previous calendar day, the emissions of NOx in pounds per hour and pounds per day and the emissions of PM2.5 and PM10 in pounds per day from each engine as follows

9.5.1 Calculate hourly and daily NOx emissions using the enhanced monitoring system approved under Condition 9.X. In the event the enhanced monitoring system is not operational for a given period, calculate hourly and daily NOx emissions ~~by~~ using the emission factors for each tested engine collected under Condition C.8.5 and electrical load data collected under Condition C.9.3, to determine emissions from that source. Emissions shall be calculated for each ten-minute load reading for each engine.

9.5.2 Calculate daily PM emissions using the emission factors for each tested engine collected under Condition C.8.5 and electrical load data collected under Condition C.9.3, to determine emissions from that source. Emissions shall be calculated for each ten-minute load reading for each engine.

~~9.6. For the purposes of Conditions C.9.4 and C.9.5, if a specific emission unit has not been tested yet, the permittee shall use the highest emission factor for the corresponding load from the test results for any of the generator engines that have already been tested.~~ (All engines have been tested so this condition is obsolete.)

9.7. For the purposes of Condition C.9.5, if the enhanced emissions monitoring system is not operational and a specific load reading is missing, the permittee shall calculate the emissions for that missing load reading by using the emission factor and load combination that results in the highest emissions rate for that emissions unit. ~~If the engine in question has not been tested yet, the permittee shall use the emission factor as provided for in Condition C.9.6.~~

9.8. For the purpose of Condition C.9.5, if the enhanced emissions monitoring system is not operational and either the urea pump is not operating or if the catalyst inlet temperature, measured in Condition B.14, is less than 250°C, calculate emissions of NOx for the affected time period by using an uncontrolled emission factor determined pursuant to Condition 8.5.

An enhanced monitoring system for NOx emissions would replace the periodic use of a portable emissions analyzer. Modify Condition B.14.6 to remove the requirement to use the portable analyzer if an approved enhanced monitoring system is in place.

14.6. Monitor and record NOX emissions (ppm) from the exhaust of each SCR unit once per week using a portable NOX monitor that meets the requirements of EPA OTM 13

found at http://www.epa.gov/ttn/emc/prelim/otm13.pdf. This requirement does not apply if an approved enhanced monitoring system is implemented.

1.7 Compliance with Ambient Air Quality Standards and PSD Increments

This revision application proposes several changes that affect NOx emissions, so a dispersion modeling analysis addressing the net effect of all changes is included in Appendix D. That analysis confirms that the emissions increase from the Discoverer generators as outlined in this section will not cause or contribute to violations of the NO_2 ambient air quality standards or PSD increment.

2 Substitute Catalytic Diesel Particulate Filters for Oxidation Catalyst Units

The Discoverer Chukchi Sea PSD permit identifies technologies and emissions limits in conditions stemming from the BACT determination for Discoverer emission units. For particulate matter, carbon monoxide, and VOC emissions, the permits specify either oxidation catalysts or catalytic diesel particulate filters, depending on the engine. An oxidation catalyst is a flow-through device that achieves significant CO and VOC reductions and a modest reduction of the soluble organic fraction of PM. A diesel particulate filter (DPF) is a wall flow device used to trap particulate matter; it can be catalyzed to achieve additional reductions identical to an oxidation catalyst, in which case it is called a catalytic diesel particulate filter (CDPF). A DPF or CDPF burns off trapped particulate matter through a process known as thermal regeneration which, as the name suggests, depends upon exhaust temperature. In general, CDPFs cost more and achieve greater PM reduction than oxidation catalysts.

The determination of which control option is required by the permit depended in part on cost effectiveness information provided in Shell's application. This revision request is necessary because Shell chose to accept the additional cost associated with CDPFs on some engines even though an oxidation catalyst had been deemed BACT in the permit.

2.1 Emission Units with CDPFs substituted for Oxidation catalysts

During the process of retrofitting the Discoverer and associated fleet with equipment and controls in order to meet Permit requirements, Shell purchased and installed CDPFs rather than oxidation catalysts on several emission sources. Table 2-1 lists the emission units on which CDPFs were substituted.

Table 2-1: Discoverer Emission Units with CDPFs substituted for Oxidation catalysts

Emission Unit	Emission Unit ID	Permit-required Emission Controls	As-built Emission Controls
Generator Engine	FD-1, FD-2, FD-3 FD-4, FD-5, FD-6	SCR, oxidation catalyst, CCV	E-POD (SCR, CDPF), CCV
MLC Air Compressor	FD-9	Oxidation catalyst	CDPF

2.2 Catalyzed Diesel Particulate Filters Control Efficiency

The CDPFs contain an oxidation catalyst and a filter membrane for more efficient removal of particulate matter than an oxidation catalyst alone, therefore satisfying the requirement of installing an oxidation catalyst, but with better particulate control. Table 2-2 provides the control efficiencies used in Shell's PSD permit application for the three criteria pollutants affected by these types of controls, PM, CO and VOCs, showing that CDPFs have better control efficiencies than oxidation catalysts. For all three pollutants the control efficiencies are either equal to or better with the CDPFs so the substitution is an improvement. The CDPF control efficiencies listed in Table 2-2 are from the CleanAIR manufacturer's data sheet (Appendix E).

Table 2-2: Control Effectiveness Used for Oxidation Catalysts and CDPFs			
Device	**$PM_{2.5}$**	**CO**	**VOC**
Oxidation catalyst	50%	47% / 80%*	70%
CDPF	85%	90%	90%

* 47% control assumed for MLC air compressor; 80 percent control assumed for D399 generator engines.

2.3 Location and Configuration of CDPF

The substituted CDPFs are installed in the same locations and configurations permitted for the oxidation catalyst units. The application did not specify dimensions or internal diagrams of the oxidation catalysts. The internal layout and catalyst formulation of the CDPFs are not included because CleanAIR Systems considers the information proprietary and was unwilling to provide it to Shell. However, Appendix B provides a schematic of the E-POD system installed on the D399 generator engines. The E-POD system combines CDPF with SCR in a single unit.

2.4 Oxidation Catalyst Monitoring, Record-keeping and Reporting Requirements

The monitoring, record-keeping, and reporting (MRR) requirements for the permitted oxidation catalyst units are presented below. Units that are installed with continuous monitoring systems (CMS) are subject to additional monitoring requirements as detailed below. The permit condition numbers are listed for reference purposes.

2.4.1 Generator Engine Oxidation Catalyst MRR Permit Conditions

Condition B.15 is in the Source Wide Requirements section of the Permit:

B.15 **Oxidation Catalyst Control Device Monitoring**. For any emission unit that is required by this permit to be controlled by an oxidation catalyst control device, the permittee shall install, calibrate, operate, and maintain (in accordance with manufacturer specifications) CMS to measure and record inlet temperature (ºF), and catalyst activity (CO ppm concentration) as follows:

15.1 (Prepare and submit 60 days before the first drilling season a site-specific monitoring plan that addresses the monitoring system design, data collection, quality assurance, and quality control elements outlined in this condition. Install, calibrate, operate, and maintain each CMS according to the procedures in the approved site-specific monitoring plan. The plan shall address the performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, sensor tolerance and sensitivity, and data acquisition and calculations; sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements; equipment performance checks, system accuracy audits, or other audit procedures; ongoing operation and maintenance procedures; and ongoing reporting and recordkeeping procedures.

15.2 The temperature CMS shall collect data at least once every 15 minutes.

15.3 Conduct the CMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan within 60 days prior to each drilling season and at least once every 3 months for the duration of the drilling season.

15.4 Conduct a performance evaluation of each CMS in accordance with the site-specific monitoring plan.

15.5 Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), operate the CMS at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Complete monitoring system repairs in response to monitoring system malfunctions and return the monitoring system to operation as expeditiously as practicable.

15.6 Monitor and record CO emissions (ppm) from the exhaust of each oxidation catalyst unit once per week using a portable CO monitor that meets the requirements of EPA OTM 13 found at http://www.epa.gov/ttn/emc/prelim/otm13.pdf.

15.7 Report as a permit deviation under Condition A.17.3 any periods during which the inlet temperature is less than 300°C, or the CO concentration is 120% or more than the CO concentration measured during the most recent previous source test that produced compliance data or emission factors for this permit.

Condition C.2 is a requirement for Discoverer Generator Engines FD-1-6:

C.2 **Operation of Oxidation Catalyst**. At all times that any of Units FD-1 – 6 are in operation, the exhaust from each emission unit shall be directed to an operating oxidation catalyst.

2.4.2 Mud Line Cellar Air Compressor Engine Oxidation Catalyst Monitoring

Condition F.1 is a requirement for Mud Line Cellar Compressor Engines FD-9-11. Engines FD-10-11 have permitted Oxidation catalyst units installed for control of emissions.

F.1 **Operation of Oxidation Catalyst**. At all times that any of Units FD-9 – 11 are in operation, the exhaust from each emission unit shall be directed to an operating oxidation catalyst.

2.5 Identification of Monitoring Equipment Installed on CDPF

The CDPFs controlling emissions from units FD-1-6 are installed in CleanAIR E-POD control systems. E-POD units combine CDPF with SCR to control emissions, and are required to measure and monitor the parameters listed in Table 2-3. These are the same parameters required by each permit to be measured and monitored if using oxidation catalyst control devices. Monitoring Equipment installed on engines FD-1-6 control devices are provided in Table 2-4.

The CDPF installed on engine FD-9 is identical to those installed on engines FD-1-6, however, it is not combined with SCR in an E-POD control system. Instead, like other Discoverer engines controlled through CDPF, it is attached to a CleanAIR HiBACK USB unit certified by California Air Resources Board as a reliable means of reducing PM by 85 percent. The same HiBACK unit is required by the PSD permit for other CDPF-equipped engines for demonstrating the proper functioning of a CDPF. The HiBACK USB is a microprocessor-based data logger and alarm system designed to record and monitor exhaust backpressure and temperature. CleanAIR's product specification for HiBACK USB units is provided as Appendix F.

Table 2-3: Measurements Included in the CMS with Thresholds

Parameter	Limit	Sampling Frequency	Permit Condition	Affected Emission Units
SCR Inlet temperature	> 250° C	At least every 15 minutes	B.14 (B.28)	Discoverer FD1 – 6 IB1 propulsion and generation IB2 propulsion and generation
SCR Urea flow	Flow must exist	At least every 15 minutes	B.14 (B.28)	Discoverer FD1 – 6 IB1 propulsion and generation IB2 propulsion and generation
SCR NOx emission concentration	< 150% of most recent stack test (in ppm)	Once per week	B.14 (B.28)	Discoverer FD1 – 6 IB1 propulsion and generation IB2 propulsion and generation
Oxidation catalyst/CDPF inlet temperature	> 300° C	At least every 15 minutes	B.15 (B.29)	Discoverer FD1 – 6 Discoverer FD10 – 11 IB1 propulsion and generation IB2 propulsion and generation
Oxidation catalyst/CDPF CO emission concentration	< 120% of most recent stack test (in ppm)	Once per week	B.15 (B.29)	Discoverer FD1 – 6 Discoverer FD10 – 11 IB1 propulsion and generation IB2 propulsion and generation

Table 2-4: Sensor Specifications, Signal Processing and Transmittal

Vessel / Emission Unit	Parameter	Model Number	Performance Criteria	Specification	Signal Processing and Transmittal
Discoverer / FD1 – 6 SCR & Oxidation catalyst/CDPF	Inlet temperature	Tempco P/N TTM00015. K type thermocouple	Range: 100 – 400°C Precision: +/- 7C*	Range: 0 – 1260 ^{o}C Transmitter accuracy: 0.2% of span which is 2.5^{o}C**	Signal from SCR processor to ADM. Then interrogated by AQ computer & sent to office by internet daily.
Discoverer / FD1 – 6 SCR	Urea Flow on/off	Grundfoss DME 60 metering pumps	Differentiate between flow and no flow	Accuracy: 1% No-flow defined as < 5% of max which is < 3 l/hr	Signal from SCR processor to ADM. Then interrogated by AQ computer & sent to office by internet daily.
Discoverer / FD1 – 6 SCR	NOx and CO conc.	Testo 350	Provided in ASTM 6522-00		Manual recording, scan sent to office by internet weekly.

*From Stack Test Method 2A and 2% of minimum absolute temperature	ADM – TASC data logger / processor
** http://www.tempco.com/sensors/Style_TTM.htm	AQ – air quality

2.6 Proposed Permit Term Revisions

Substitution of the better performing CDPF for oxidation catalysts requires the following permit conditions to be edited, added or replaced.

CleanAIR E-POD systems installed on FD-1 through FD-6 are designed to combine SCR with either oxidation catalysts or CDPFs. The E-POD units are designed with a comprehensive system to monitor operational parameters regardless if an oxidation catalyst or a CDPF is installed in the unit. Therefore Shell elects to not use the HiBACK unit, but to monitor these catalysts also using the E-POD CMS. As there is no change to the CMS as a result of substitution of CDPF in place of an oxidation catalyst, the MRR requirements for these emission units are not affected. Therefore, these units continue to be subject to permit condition B.15, which describes requirements for CMS.

MRR for emission unit FD-9 are addressed with the HiBACK pre-programmed data interrogation sensors, algorithms and data records. Therefore FD-9 should not be subject to the CMS requirements of condition B.15. Condition B.15 should be revised as follows to account for the different control device (edits are underlined):

B.15 **Oxidation Catalyst and Combined Catalytic Diesel Particulate Filter Control Device Monitoring**. For any emission unit that is required by this permit to be controlled by an oxidation catalyst control device or a CDPF combined with SCR control system, the permittee shall install, calibrate, operate, and maintain (in accordance with manufacturer specifications) CMS to measure and record inlet temperature (ºF), and catalyst activity (CO ppm concentration) as follows:

15.1 Prepare and submit 60 days before the first drilling season a site-specific monitoring plan that addresses the monitoring system design, data collection, quality assurance, and quality control elements outlined in this condition. Install, calibrate, operate, and maintain each CMS according to the procedures in the approved site-specific monitoring plan. The plan shall address the performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, sensor tolerance and sensitivity, and data acquisition and calculations; sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements; equipment performance checks, system accuracy audits, or other audit procedures; ongoing operation and maintenance procedures; and ongoing reporting and recordkeeping procedures.

15.2 The temperature CMS shall collect data at least once every 15 minutes.

15.3 Conduct the CMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan within 60

days prior to each drilling season and at least once every 3 months for the duration of the drilling season.

15.4 Conduct a performance evaluation of each CMS in accordance with the site-specific monitoring plan.

15.5 Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), operate the CMS at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Complete monitoring system repairs in response to monitoring system malfunctions and return the monitoring system to operation as expeditiously as practicable.

15.6 Monitor and record CO emissions (ppm) from the exhaust of each oxidation catalyst unit or combined CDPF and SCR system once per week using a portable CO monitor that meets the requirements of EPA OTM 13 found at http://www.epa.gov/ttn/emc/prelim/otm13.pdf.

15.7 Report as a permit deviation under Condition A.17.3 any periods during which the inlet temperature is less than 300°C, or the CO concentration is 120% or more than the CO concentration measured during the most recent previous source test that produced compliance data or emission factors for this permit.

Replace the condition that requires operation of an oxidation catalyst on FD-1-6, C.2, with:

C.2 **Operation of Catalyzed Diesel Particulate Filter (CDPF).** At all times that any of Units FD-1– 6 are in operation, the exhaust from each emission unit shall be directed to an operating CDPF.

2.1 The CDPF shall be equipped with an operating monitor and alarm unit, that records exhaust pressure and temperature.

2.2 During each day that each of Units FD-1-6 is operated, the exhaust temperature shall be above 300°C, or 572°F, for at least 30 percent of the time.

Of the three Mud Line Cellar Compressor Engines FD-9-11, only FD-9 is installed with a CDPF rather than an oxidation catalyst. Therefore, the condition requiring use of an oxygen catalyst should be revised as follows (edits are underlined):

F.1 **Operation of Oxidation Catalyst.** At all times that either of Units FD-10 – 11 are in operation, the exhaust from each emission unit shall be directed to an operating oxidation catalyst.

We suggest a condition that requires use of CDPF for unit FD-9 be inserted as Condition F.2, with adjustments to numbering of subsequent conditions

F.2 **Operation of CDPF.** At all times that Unit FD-9 is in operation, the exhaust shall be directed to an operating CDPF.

2.1. The CDPF shall be equipped with an operating HiBACK monitor and alarm unit, that records exhaust pressure and temperature.

2.2. During each day that Unit FD-9 is operated, the exhaust temperature shall be above 300°C, or 572°F for at least 30 percent of the time.

In addition, Shell suggests that the following two conditions be added to the Monitoring, Recordkeeping, and Reporting condition section, F.8, for Mud Line Cellar Engines FD-9-11.

F.8 ****

8.6. Monitor the exhaust temperature of FD-9 by use of the HiBACK monitor and alarm unit, whenever the engine is in operation.

8.7. Each day, calculate and record for the previous calendar day, the percent of operational time for FD-9 that the exhaust temperature was above 300°C (572°F).

No other changes are necessary to implement this revision request.

As required by the permit conditions a CMS plan has already been submitted that addresses the requirements for CDPFs installed in place of oxygen catalysts.

3 Rated Capacity for Emission Units

3.1 Introduction

Shell conducted each of several hundred emissions tests with the intent to test all emission sources per Permit requirements. In some cases, however, due to physical limitations or requirements of the vessel owner, Shell had to test units at an operating rate below the rate implied by the permit. In these instances, the maximum permissible load that the engine could be operated was deemed the 100% load case.

Maximum continuous power ratings of marine engines are often 10-20% below “name plate” power ratings. Owners employ controllers and mechanical stops to limit the amount of fuel that can be consumed by the engine to stay within owner-defined maximum continuous power output of each engine.

It should be noted that neither the Discoverer nor the vessels comprising its Associated Fleet are owned by Shell. Shell charters the vessels from companies that desire to protect their assets from damage. Unlike power plants and on-road diesel vehicles, engines in vessels are built into the hull and cannot be economically replaced in total. Vessel owners sometimes take additional steps to limit the operating level of their engines to extend their useful life.

The following sections provide information on the de-rating of certain engines onboard the Discoverer and the Nanuq in a format consistent with Richard Albright’s June 6, 2012 letter to Susan Childs. Note that while the June 28 application requested de-rating of the Fennica propulsion engines and associated monitoring conditions, Shell withdrew those requests in an August 14 letter from Susan Childs to EPA Region 10, because existing permit condition N.4 was deemed sufficient. The following sections 3.2 and 3.3 supersede the requests made in Chapter 3 of the June 28 application.

3.2 Noble Discoverer

1. *Identification of each emission unit for which Shell is proposing to define the maximum operating capacity at a level below that identified in the permit.*

   Emission units FD-1-6 (main generators), which are Caterpillar D 399’s rated at 988 kW each.

2. *Identification of the proposed de-rated maximum operating rate.*

   Caterpillar D 399’s de-rated to maximum operating rate of 800 kW.

3. *Description of the physical or operational limitation which forms the basis for the de-rating request.*

   Noble, the owner of the Discoverer, has established 800 kW as the maximum operating rate for the generators, and has installed an electrical distribution system with controls that limit the engines’ operating rate accordingly. This operating rate is nearly 20 percent lower than the 988 kW nameplate rating on the engine. With this contractual and operational restriction in place, Shell submits that an engine operating rate that results in 800 kW output reflects the

true 100 percent engine load to be encountered during our OCS drilling operations, and that the "100% load" source tests should take place at this restricted engine operating rate. Similarly, source tests at 75% and 50% load should be conducted at engine operating rates that generate 600 and 400 kW, respectively. (From Jan 11, 2012 letter from Susan Childs to EPA's Natasha Greaves)

4. *Description of any engineering or administrative controls which will be put in place to ensure each emission unit cannot operate above the proposed de-rated maximum, if appropriate.*

   The vessel owner installed a power distribution system which limits the load on any engine to 800 kW. Review of the power output for the 2012 season confirms that the control software effectively limits power output as the owner intends.

5. *Proposed monitoring, record keeping, and reporting to be used to verify compliance with the proposed de-rated maximum operating rate.*

   Condition C.9.3 of the Permit requires Shell to monitor and record the power output (in kWe) from each generator engine at least every 10 minutes. No additional monitoring requirements are warranted.

3.3 Nanuq (OSR Vessel)

1. *Identification of each emission unit for which Shell is proposing to define the maximum operating capacity at a level below that identified in the permit.*

   Emission units N-1-2 (main propulsion engines), which are Caterpillar 3608's rated at 2,710 kW.

2. *Identification of the proposed de-rated maximum operating rate:*

   Proposed de-rated maximum engine capacity:

   Caterpillar 3608's de-rated to 1927 kW

3. *Description of the physical or operational limitation which forms the basis for the de-rating request.*

   The main propulsion engines are controlled by a Power Management System (PMS) developed by Marine Technologies which limits power that can be applied to main engines to approximately 80% of maximum continuous power. This PMS system cannot be overridden on the bridge. It was installed by the vessel owner to prevent vessel master from damaging main propulsion engines. Moving the main engine throttles to full (e.g. 100% scale) one at a time or in tandem translates to a maximum measured fuel consumption of 134 gal / hr. Using attached power / fuel consumption curve, this fuel consumption translates to 1927 kW or 71% of maximum power.

4. *Description of any engineering or administrative controls which will be put in place to ensure each emission unit cannot operate above the proposed de-rated maximum, if appropriate.*

   The vessel owner will not adjust the power management system for the duration of this season.

5. *Proposed monitoring, record keeping, and reporting to be used to verify compliance with the proposed de-rated maximum operating rate.*

   Condition Q.9.4 of the Permit requires Shell to monitor and record fuel usage for each propulsion engine on an hourly basis. No additional monitoring requirements are warranted.

4 Nanuq Particulate Matter Emission Limits

For emission units not subject to BACT, such as those on associated fleet vessels, Shell's permit application proposed emissions limits based on various estimates, assumptions, and information sources, including data from engine manufacturers and control equipment vendors. Shell's consultants used this information to propose as stringent emission limits as the available facts and assumptions appeared to allow. Shell has now found that assumptions made to estimate particulate matter (PM) emissions from the primary oil spill response vessel (OSRV), the Nanuq, could not be met in practice. This resulted in underestimating PM emissions and proposing daily PM limits for the Nanuq that the CDPF-controlled engines on the vessel cannot meet. The following section explains how Shell underestimated Nanuq PM emissions in its application, proposes revised daily PM limits, and provides the technical basis for the revised limits.

4.1 Background

The Nanuq is powered by two propulsion engines (N-1 and N-2) and two generator engines (N-3 and N-4). The propulsion engines are Caterpillar 3608 engines rated at 2,710 kW. The generators are powered by Caterpillar 3508B engines rated at 1,285 kW. The engines are required to combust only ultra-low sulfur distillate fuel. Exhaust from each engine is controlled by a CDPF designed to reduce PM emissions by 85 percent.

Serving as an OSRV, the Nanuq propulsion and generation engines are governed by aggregate daily PM10 and PM2.5 (hereafter, collectively, PM) emission limits.[16] Shell is asking EPA to revise the 3.03 lbs/day limits in Conditions 4.1.1 and 4.1.2, which read as follows:

Q.4. Daily Emission Limits: At all times while the Discoverer is an OCS source and the Oil Spill Response fleet is within 25 miles of the Discoverer, emissions from the Oil Spill Response Fleet shall not exceed the emission limits specified:

- 4.1. Nanuq propulsion engines and generators in aggregate (Units N-1 – 4):
  - 4.1.1. PM10: 3.03 lbs/day
    - 4.1.1.1. For compliance with Condition Q.4.1.1, measurement of PM10 shall be determined using EPA Method s 201A and 202.
  - 4.1.2. PM2.5: 3.03 lbs/day
    - 4.1.2.1. For compliance with Condition Q.4.1.2, measurement of PM2.5 shall be determined using EPA Methods 201A and 202.

[16] The PM10 and PM2.5 emission limits are the same because it is assumed that all PM emissions are less than 2.5 microns in diameter. Therefore, the discussion in this section does not differentiate between PM2.5 and PM10.

4.2 Basis for Existing Emission Limits

The current permit limits were derived using manufacturer provided information, operational information, average brake-horsepower specific fuel consumption, and the heating value of diesel fuel, as follows:

- The daily fuel limit was determined by:
  - Calculating the product of the aggregate rated engine power (9,838 horsepower), the average brake HP-specific fuel consumption (7,000 Btu/hp-hr, as provided in AP-42 Table 3.3-1 footnote a), and the load factor (the power anticipated to be used divided by the power available, 30%).
  - Dividing the calculated value from above by the diesel heating value (133,100 Btu/gallon of fuel) to determine the daily fuel limit (rounded 3,725 up to 3,800 gallons per day).
- The daily PM limit is coupled to the fuel limit, and was determined by:
  - Identifying a PM emission factor from Caterpillar's Model 3608 data sheet, while operating at 100% load (0.17 g/kW-hr), see Appendix G.
  - Using the Caterpillar emission factor to determine an emission factor in pounds of PM emissions per gallon of fuel combusted, as follows:
    - Converting the emission factor to lb/hp-hr and dividing by the average horsepower-specific fuel consumption (7,000 Btu/hp-hr), to determine the emission factor in lb/MMBtu.
    - Calculating the product of the above emission factor and the diesel heating value (133,100 Btu/gallon of fuel) to determine the uncontrolled emission factor.
    - Applying the efficiency of the control device, in this case catalytic diesel particulate filter (CDPF) (85% control efficiency), to determine the controlled emission factor (0.000798 lb/gal).
  - Applying the emission factor to the daily fuel limit results in a daily PM limit of 3.03 lb/day.

4.3 Nanuq PM Source Test Results

Source tests conducted by TRC Environmental Corporation in March 2012 on the Nanuq engines showed that the 3.03 lbs/day limits were too stringent. Using EPA Reference Methods 5 and 202, TRC measured PM from N-1 at 100% and 25% loads, N-2 at 100% load, and N-4 at 90% and 50% loads. The March test results revealed PM emissions from engine N-2 that were almost five times higher than those for the identical N-1. However, even if the single high PM test result were discounted, the measured emissions rates were too high to allow operation of the Nanuq while still complying with the daily PM emission limits.

4.4 Improvements to Nanuq Engines and CDPFs

The presumed cause of the high PM during the second test run of N-2 was a combination of low exhaust temperatures upstream of the catalysts and a potentially incorrect set of injectors on the

engine, leading to poor catalyst performance and a build-up up of soot in the stack. As temperatures reached ignition temperature, the soot was released. A possible contributing factor was that back pressure built up so high that internal baffles flexed and soot leaked around filters. Indeed, subsequent investigations revealed cracks in the internal baffles that would allow soot to pass through uncontrolled.

The high PM measured on the second test run of N-2 prompted Shell to reevaluate each of the four engines and each CDPF on the Nanuq. The following components were replaced or repaired:

- Thermocouple on N-4 was defective, which led to incorrect pre-heater performance, affecting catalyst performance.
- Heating unit wires melted on two units and needed to be replaced.
- Circuit breakers for port main and starboard main heater units were tripped. Circuit breakers were reset. Maintenance check list now includes checking heater circuits.
- HiBACK systems for N-2, N-3, and N-4 were replaced.
- Fuel injectors on N-2 were replaced and timing was checked on all engines. The injectors were an old part number that had different valve clearance specifications. All engines now have current fuel injector series and are set to factory specifications.
- One additional filter was installed in the N-3 and N-4 CDPFs for a total of 6 filters per CDPF unit. Four additional filters were installed in the N-1 and N-2 CDPFs for a total of 20 filters per CDPF unit. This reduced backpressure because they were installed where the stack was previously blocked off.
- Routine maintenance and valves checks and replacements were performed, and Caterpillar and CleanAIR support staff validated that engines and filters were operating correctly.

In addition to these mechanical adjustments, the following operational improvements were implemented before commencing operation:

- Additional operator training on proper maintenance of units was conducted.
- The HiBACK system has status lights that indicate proper operation but a laptop is required to interrogate unit for historical temperatures and back pressures. Shell added a laptop with appropriate software to interrogate the HiBACK systems which are indicators of CDPF performance.
- Shell installed analog air pressure gauges (manometers with about 1% error) upstream of catalysts to provide visible, real time indication of CDPF back pressure.
- Shell added audible alarms to HiBACK units to monitor backpressure.

4.5 June 2012 Source Tests

In June 2012, Shell conducted additional source tests of the Nanuq propulsion and generator engines after the repairs were completed. Emissions were measured at 25, 50, 75 and 100% load capacity for the main engines (N-1, N-2) and at 50 and 100 percent load for the generator

engines (N-3, N-4). Because the new Method 202 requires significant time to dry the condensable fraction, the PM test results were not available when the June revision application was submitted.

Due to the improvements and repairs made after the March tests, and a qualitative assessment of the filters, Shell anticipated that PM measurements would be more consistent and might be lower than those conducted in March. In the June application, however, Shell conservatively proposed PM emission limits based on the March tests.

Shell provided the results of the June emissions tests of the Nanuq engines by email on July 27, 2012. In an August 6 letter from Susan Childs to Richard Albright, Shell indicated that the June emissions testing of Nanuq propulsion and generator engines supported a lower aggregate emission factor than what had been proposed in the June 28 application, given the daily fuel allowance that applies to the oil spill response vessel. Shell proposed that the aggregate particulate matter emission limits in permit conditions Q.4.1.1 and Q.4.1.2 be revised from 3.03 to 10 pounds per day. Shell affirms that August 6, 2012 request with this permit application.

4.6 Proposed Revised Particulate Matter Limits

The Nanuq engine source test results indicate that the CDPF-controlled Nanuq engines cannot meet the 3.03 lbs/day PM emission limits.

4.6.1 Requested PM Emission Limits and Compliance Monitoring Method

Shell requests that the PM10 and PM2.5 emission limits be revised from 3.03 to 10 pounds per day, which is a 0.42 ton increase in potential annual emissions. This is well below the 10 ton PM2.5 significant emissions increase and the 15 ton PM10 significant emissions increase that constitute major modifications under the PSD permit program. Furthermore, there is no BACT requirement for emission units on the Associated Fleet vessels. The only applicable regulatory requirement is that the exploration operations continue to comply with ambient air quality standards; that issue is addressed in Appendix D.

As well as revising the PM emission limits, Shell requests that actual emissions from the Nanuq propulsion and generation engines be calculated by the same method as is allowed for the Discoverer prime generators (Condition C.9.5), the ice management vessels (Conditions N.13.12 and O.13.12) and the supply vessel (Condition P.5.7). This method uses per-engine power level-specific emission factors to calculate actual emissions. This requested calculation of emissions using a power-level specific emission factor will provide a more accurate tracking of actual Nanuq emissions.

Prior to the June 2012 emissions tests, there was no way to quantify the engine propulsion engine load, and the relationship of fuel consumption to load on those two engines was not demonstrated. However, the June 2012 stack tests of those two engines established that relationship. With that new information, it is clear that the current permit requires a calculation of emissions that is now unnecessarily conservative (higher than the actual emissions) because engine load can now be quantified for all four Nanuq engines.

Nanuq has two direct-drive propulsion engines (N1 and N2) and two generator engines (N3 and N4). The Nanuq propulsion engines do not have power measurements in the form of electrical power but they each have fuel consumption measurements on a 10-minute frequency. The June stack tests demonstrated that these fuel consumption measurements are an excellent surrogate for power level measurements.[17]

The power levels of the generator engines is being measured directly (as kWe) on a 10-minute frequency, as is required for the Discoverer prime generators and ice management engines. Shell proposes to calculate mass emissions by applying source test-derived emission factors to fuel consumption by the propulsion engines and to electrical power produced by the generators.

4.6.2 Proposed Permit Text Revisions

In order to implement the requested revisions, Shell proposes the following specific permit condition revisions:

Q.4 Daily Emission Limits: ****

4.1. Nanuq propulsion engines and generators in aggregate (Units N-1 – 4):

4.1.1. PM10: ~~3.03~~ 10 lbs/day

4.1.1.1. For compliance with Condition Q.4.1.1, measurement of PM_{10} shall be determined using EPA Method s 201A and 202.

4.1.2. PM2.5: ~~3.03~~ 10 lbs/day

4.1.2.1. For compliance with Condition Q.4.1.2, measurement of $PM_{2.5}$ shall be determined using EPA Methods 201A and 202.

Q.9. Monitoring, Recordkeeping and Reporting. ****

9.4. Monitor and record fuel usage for each propulsion engine (N-1 and N-2) and power output for each generator engine (Units N-3 and N-4) at least hourly.

9.7. Each day, calculate and record for the previous calendar day, the emissions of NOX, $PM_{2.5}$ and PM_{10}, in pounds per hour and pounds per day using the ~~highest~~ emission factor for each tested engine collected under Condition Q.8.5 and ~~fuel usage~~ load data collected under Condition Q.9.4. Load will be determined from fuel usage for N1 and N2, and directly from electrical load for engines N3 and N4. Emissions shall be calculated for each ten-minute load reading for each engine.[18]

[17] Appendix H presents propulsion engine fuel consumption data as a function of power level. A linear regression of the plots for N1 and N2 is determined and the resulting linear equation is provided along with the correlation coefficient (r^2). The correlation coefficients are 0.9997 for each, confirming that fuel flow is an excellent surrogate for propulsion engine load.

[18] Note that the June 28 revision application also proposed that monitoring of actual emissions be based on load. However, the August 14 letter from Susan Childs to EPA Region 10 provided additional detail on how the load would be determined, and the text for Condition Q.9.7 was revised. Shell withdraws the June 28, 2012 language proposed for Condition Q.9.7 and proposes instead the language proposed on August 14 and repeated here.

No other changes to the PSD permit are required to implement these requested revisions.

4.7 Compliance with Ambient Air Quality Standards and PSD Increments

This revision application includes several changes that affect PM emissions, so a dispersion modeling analysis addressing the net effect of all changes is included in Appendix D. That analysis confirms that the emission increases from the Nanuq and other proposed changes will not cause or contribute to violations of the PM10 or PM2.5 ambient air quality standards or PSD increments.

5 Revise Permit Conditions for Crane and Cementing Unit Engines

The Discoverer's two crane engines (FD14 and FD15) and two cementing unit engines (FD16 and FD17) are fitted with catalytic diesel particulate filters (CDPFs), which were proposed as BACT for these engines. With operating experience in September and October 2012, it is apparent that the duty cycle of the crane and cementing unit engines is such that the exhaust temperatures are not high enough to activate the catalysts. Thus, the oxidation component of the CDPFs does not oxidize volatile organics, diesel particulate matter, and carbon monoxide. Furthermore, without the catalyst operating, the filter clogs, exhaust back-pressure increases, and the engine does not operate properly. Shell believes that these operational realities demonstrate that CDPFs are not technically feasible for engines FD14-17, and therefore are not BACT. Instead, Section 5.1 concludes that BACT for these engines is good combustion practice, closed crankcase ventilation, and use of ultra-low sulfur distillate fuel. As a consequence there will be an increase in the BACT emission factors (g/kW-hr) and short and long-term mass emissions of PM, CO, and VOC. There will be no change in the BACT-related NOx emission factors for the cementing or crane engines due to removal of the CDPFs.

The 2012 operating experience also revealed that the duty cycle for the crane engines was underestimated when establishing hourly fuel use. This hourly fuel consumption was used to establish a one-hour NOx emission limit, which calculations indicated was exceeded eight times in 2012. Shell believes the low duty assumption is representative of operations over the course of a day and over the course of the season, but not for a single hour. While the hourly NOx mass emission limit is the only Permit condition that must be changed due to increased hourly fuel consumption, the modeling analysis in Appendix D also addresses hourly emissions increases of other pollutants that will increase as a result of a higher hourly operating rate.

Shell made a similar erroneous assumption when estimating hourly duty cycle for the cementing engines. Although no deviation or excess emissions reports were filed in 2012 due to higher than expected hourly operations for a cementing engines, Shell anticipates that the need to operate at a higher rate will arise at some point. Consequently, Shell proposes to revise the assumed duty cycle for the cementing engines. As noted for the crane engines, only the hourly NOx emission limit needs to be revised, but hourly emissions of other pollutants will increase as a result of a higher hourly operating rate and these increases are addressed in Appendix D.

Finally, Section 5.3 requests EPA's authorization to replace the Discoverer's cranes if Shell deems it cost effective to do so. Shell commits to meeting the emissions limits established for new technology engines if the cranes are replaced.

Section 5.4 identifies the specific changes in Permit conditions that are required to accommodate the requests in Sections 5.1, 5.2, and 5.3.

5.1 Request to Remove CDPFs from Crane and Cementing Unit Engines

The typical duty cycle of the cranes is one of lifting a load for a short period of time, usually less than one minute, swinging the boom, lowering the load, then idling while the load is disconnected and a new load is connected. High power is needed only for lifting the load, which

is a small part of the duty cycle. Although exhaust temperature increases during this loading, 2012 experience indicated the high engine load was not consistent enough for the exhaust temperature to reach 300°C.

The cementing unit engines exhaust temperature will also rarely, if ever reach 300°C, but for a different reason. For specialized drilling procedures – logging and cementing, for example – Shell leases portable equipment from third party vendors, regardless of the drillship. Shell contracted with Halliburton to provide the cementing and pressure testing equipment for the Discoverer, which included two diesel-powered cement pumps and cement mixing equipment. Halliburton provides all of its customers with a standard engine/pump combination for cementing services regardless of cementing needs related to well depth or geometry. They provide the same pumping equipment for a 4,000-foot deep well as they do for a 24,000-foot deep well because the cementing unit serves as a back-up system to the rig mud pumps in the event that a well control situation arises. The additional capability permits the unit, using both pumps, to achieve high flow rates at high pressures, a critical requirement of a well-control capability. For the relatively basic well designs in the Chukchi Sea, the equipment is significantly oversized and is therefore rarely loaded even close to its capacity during normal operation. As a consequence of these low loads, the engine does not develop the exhaust temperature required to meet the 300°C minimum temperature required to activate the CDPF unit.

During the 2012 season, two shallow casing strings were cemented. In 2013, Shell intends to cement tubulars isolating the deeper sections of the well. The cementing operations will increase engine load but the increased load is not expected to be sufficient to raise the exhaust temperature enough to meet the permit requirements. In addition, after drilling out of each casing string, a formation “leakoff” test will be performed. This test, a requirement of the drilling permit, is performed using a cement unit pump because cement unit pumps can accurately pump small volumes at low rates. The engine load for this approximately one hour operation will likely be about five percent of the engine nameplate rating. Shell also plans to drill several additional wells during the 2013 season. Cementing operations in the shallow intervals of these wells can be expected to produce low temperatures similar to those experienced in 2012.

Engine exhaust temperature for the two crane and two cementing engines has been measured on a five-minute frequency as a part of the continuous monitoring system (CMS) required by Permit condition B.15. During operations in September and October 2012, Shell modified its operation of certain emission units in an effort to minimize periods of control device non-operation. For the cranes and cementing engines, Shell focused on minimizing engine idle time. This procedure was in place by approximately October 5, 2012. So for this control device operational analysis, Shell selected the 24-day period from October 5 through the end of the season, October 28, as representative of normal operation

The 5-minute data record for this period of operation includes engine exhaust temperature and fuel flow data. Because the crane and cementing unit engines operate intermittently, the data were scanned for “in operation” periods by searching for periods when exhaust temperature

exceeded 80°C.[19] A two-page sample of the data for each engine is provided in Appendix I. A summary of these exhaust temperatures and length of time the emissions unit was operated is provided in Table 5-1.

Table 5-1 shows that both cranes operated approximately 30 percent of this 24-day period and during this period their average exhaust temperature was 158°C. The Port Crane engine (FD-14) temperature never exceeded 300°C and the Starboard Crane engine (FD-15) exceeded 300°C for a total of 2.8 hours, spread through the period with no single event greater than 300°C lasting more than 50 minutes. Thus, FD-15 operated over the 300°C threshold for 2 percent of its operating time (2.8 hrs/145 hrs). The minimum needed to comply with the Permit is operation over 300°C for 30 percent of the time the emission unit is operated on a daily basis. Thus, during representative operation of the cranes, neither crane met (or even approached) the minimum Permit requirements. Thus, use of catalytic control systems on crane engines is not feasible and BACT needs to be re-evaluated.

Shell believes that the 2012 crane use would be reasonably representative of crane use in future seasons, and in fact may have been biased toward heavier than average loads. At the beginning of a well, the casing joints (standard length of pipe) are much heavier and drill bits much larger (e.g. 30" diameter at the start, 8" diameter at the end of the well). As a well gets deeper, items that are lifted tend to be smaller and weigh less and demand less power.

Table 5-1: Engine Exhaust Temperature Summary

Emission Unit	Percent of Time operated[a]	Avg. Exhaust Temperature (°C)	Max. Exhaust Temperature (°C)
FD-14 (Port Crane)	37 % (215 hrs)	156	291
FD-15 (Starboard Crane)	25 % (145 hrs)	161	335
FD-16 (Cementing)	1.9 % (11 hrs)	121	210
FD-17 (Cementing)	1.2 % (7 hrs)	104	190

[a] within the 24-day period (6,912 five-minute periods) considered representative of long-term operations.

Similarly, the cementing unit engines experienced very little use, less than 2 percent of the 24-day operational period. Average exhaust temperature when in use was less than 104°C for FD-16 and 121°C for FD-17, with maximums at approximately 200°C, well below the 300°C needed for effective operation of the CDPFs. As discussed above, the 2012 cementing unit operating experience is believed to be conservatively representative of use in future years. Thus, use of catalytic control systems on cementing unit engines is not feasible and BACT needs to be re-evaluated.

[19] Fuel flow is not used for this purpose because during some of the low-operation times the fuel flow was sufficiently low that it was recorded as zero, but the engine was clearly running as shown be elevated exhaust temperature.

5.1.1 PSD Permit Limits

Operating the cranes or cementing engines without directing the exhaust to a CDPF will not affect NOx limits for either source. Potential emissions of PM, VOC, and CO will, however, increase without the control device. This section summarizes Permit conditions that Shell requests EPA revise; specific text changes are proposed in Section 5.5.

The crane-related conditions in Section H of the Permit that Shell proposes to revise are:

- Condition H.1 requires the crane engine exhaust to be directed to a CDPF with a HiBACK monitor, and requires that exhaust temperature be above 300°C, or 572°F, for at least 30 percent of the time.
- Condition H.2 establishes BACT Limits in g/kW-hr for PM, PM10, PM2.5, CO, and VOC
- Condition H.6 establishes daily aggregate mass emission limits for PM10 and PM2.5.
- Condition H.9 requires Shell to monitor and record the exhaust temperature of each engine and to calculate and record, the percent of operational time exhaust temperature exceeds 300°C (572°F).

The cementing engine-related conditions in Section I of the Permit that Shell proposes to revise are virtually identical to those of Section H:

- Condition I.1 requires the cementing unit engine exhaust to be directed to a CDPF with a HiBACK monitor, and requires that exhaust temperature be above 300°C, or 572°F, for at least 30 percent of the time.
- Condition I.2 establishes BACT Limits in g/kW-hr for PM, PM10, PM2.5, CO, and VOC
- Condition I.6 establishes daily aggregate mass emission limits for PM10 and PM2.5.[20]
- Condition I.10 requires Shell to monitor and record the exhaust temperature of each engine and to calculate and record, the percent of operational time exhaust temperature exceeds 300°C (572°F).

5.1.2 Efforts to Achieve PSD Permit Limits

The CDPFs required as BACT for units FD-14-FD-17 must have an exhaust temperature above 300°C to operate properly. Operational experience makes it clear that sustaining exhaust temperatures this high requires running the associated engines at a substantial load. While the operators can affect idle time by minimizing startup and shutdown idle, they have no control over the loads and idle time between loads. Crane usage is driven by the occasional need to move materials around the deck, and to and from supply vessels. Cementing unit usage is also determined by the need to stabilize the well, the frequency of which is completely dependent on the particular requirements of the well. Normally the well will require use of the cementing units operating at partial load

[20] The aggregate emissions limits cover both cementing and logging unit engines. The smallest of the cementing unit engines (FD-18) and the two logging unit engines (FD-19 and FD-20) have been electrified. Chapter 8 of this application presents Shell's proposal to eliminate Permit conditions related to these emissions units.

In an effort to maximize exhaust temperature, the crane and cementing unit engine operators were instructed to minimize the idle time before and after usage. However, the use record provided in Appendix I and summarized in Table 5-1 – which as discussed above would be representative of typical operation in any season – shows that neither cranes nor cementing activities were sufficient to bring engine exhaust temperature to the necessary 300°C to activate the catalyst. The only emission unit that ever met 300°C was the Starboard Crane engine and it exceeded 300°C only two percent of the use time.

The inability of the crane and cementing engines to achieve the required minimum inlet temperature required for proper CDPF operation during the 2012 season resulted in 77 permit deviations where the inlet temperature to the CDPF was not maintained for at least 30% of the day (although they cannot be solely attributed to low load operation, as startup conditions could also have contributed to catalyst temperature issues).

5.1.3 BACT Re-evaluation

BACT analyses for crane and cementing unit engines were provided in the January 2010 Discoverer permit application (ENVIRON, 2010).[21] That material is updated here with a current technology review of EPA's BACT/LAER Clearinghouse and California BACT emission control technology listings. As before, this analysis treats the four engines together as a group called "small diesel-fuelled IC engines." The 2010 BACT analysis concluded that technologically feasible and cost-effective controls for small diesel-fueled engines included:

1) NOx: Good Combustion Practices (GCP)
2) PM: Use of GCP, ULSD and CDPF
3) SO2: Use of ULSD
4) CO/VOC: GCP and Oxidation Catalyst

Review of the U.S. EPA RBLC[22] and CA BACT[23] listings from 2009 through the present yielded the results provided in Table 5-2. There are no entries for small diesel-fueled engines in the California database but the RBLC included the following list as possible controls:

5) Compliance with NSPS Subpart IIII (applicable to stationary sources)
6) GCP
7) ULSD

[21] ENVIRON, *Outer Continental Shelf Pre-Construction Air Permit Application. Frontier Discoverer Beaufort Sea Exploration Drilling Program*, Prepared for Shell Offshore Inc., ENVIRON Project No. 03-22090A, Revised January 2010, pp 63 - 83.
[22] Web site:http://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=eg
[23] Web site: http://www.arb.ca.gov/bact/bactnew/rptpara.htm

Table 5-2: RBLC Determinations for Small Diesel-fired Engines

RBLC ID	RBLC Search Code	Date Determination Last Updated	Process Name	Engine Rating (hp)	BACT Limit NOx	BACT Limit $PM_{2.5}$	BACT Limit PM/PM_{10}	Control Method Description
FL-0324	17.22	12/8/2011	Emergency Firewater Pump Engines	250	3 g/hp-hr	---	0.15 g/hp-hr	Compliance with 40 CFR 60, Subpart IIII
FL-0324	17.21	12/8/2011	Emergency Generator	335	4 g/kW-hr	---	0.2 g/kW-hr	Compliance with 40 CFR 60, Subpart IIII, ULSD fuel
ID-0018	17.21	10/5/2010	Fire Pump Engine	315	4 g/kW-hr	---	0.2 g/kW-hr	EPA Tier III Engine, GCP
LA-0204	17.21	8/6/2009	Emergency Engines		4.41 lb/MMBtu	---	0.31 lb/MMBtu	GCP
LA-0251	17.21	12/12/2011	Generator Engine	193	4 g/kW-hr	---	0.2 g/kW-hr	
LA-0251	17.21	12/12/2011	Fire Pump Engines	444	3 g/hp-hr	---	0.15 g/hp-hr	
LA-0254	17.21	12/12/2011	Emergency Fire Pump	350	---	0.15 g/hp-hr	---	ULSD fuel, GCP
MI-0389	17.23	12/16/2010	FGD Quench Pump	409	---	---	0.2 g/kW-hr	Engine Design, ULSD
MI-0389	17.21	12/16/2010	Fire Booster Pump	54	---	---	0.4 g/kW-hr	Engine Design, ULSD
NH-0018	17.21	7/18/2012	Fire Pump Engine	2.27 MMBtu/hr	---	---	3E-05 lb/MMBtu	
SC-0113	17.21	10/17/2012	Emergency Engines	29	7.5 g/kW-hr	---	---	Purchase of Certified Engine based on Compliance with 40 CFR 60, Subpart IIII
SC-0113	17.21	10/17/2012	Fire Pump	500	4 g/kW-hr	---	---	
*WY-0070	17.21	8/27/2012	Fire Pump Engine	327	---	---	---	EPA Tier III Engine
*WY-0071	17.21	10/15/2012	Emergency Air Compressor	400	---	---	---	EPA Tier III Engine

* Draft determinations.

Shell commits to GCP and the use of ULSD as components of BACT for the crane and cementing unit engines. This leaves catalyst control (oxidation catalysts and CDPFs) and engine replacement with current technology (the nonroad engine equivalent of meeting Subpart IIII for stationary sources) as options to be addressed in the BACT analysis. The analysis above demonstrates that catalytic controls are not technically feasible for crane and cementing engines because they do not operate at high enough load. These controls, therefore, are not BACT. Thus, use of current technology engines remains under consideration in the BACT analysis.

Crane Engine Replacement Cost / Benefit Analysis

Current technology engines for the cranes are Marine CI Category C1, Tier 2 engines and these are technologically feasible. The next step in the BACT review process (Step 4) is to evaluate replacement of the existing crane engines with current-technology engines considering energy, environmental and economic impacts.

Shell requested that engineers from Noble evaluate the feasibility of changing engines on the existing National OS435 pedestal cranes. A November 26, 2012 email from Garth Pulkkinen, summarized that evaluation as follows:[24]

> "When considering possibilities for *Noble Discoverer* cranes moving forward, the option of simply replacing the engine (prime mover) of the existing National OS435 pedestal cranes poses significant technical challenges that render it not feasible. A diesel-hydraulic crane is a complex machine that has multiple functions that depend on precise matching between the prime mover and the hydraulic pumps that power those functions. The prime mover feeds rotating input into a gear set that, in turn, rotates hydraulic pumps. These pumps feed hydraulic pressure and flow to the hydraulic motors that perform the physical work of the crane. The gear set is designed specifically to an engine, and the hydraulics are designed specifically to a gear set, so the entire function of the crane is designed around a specific prime mover, in this case, a specific diesel engine model. The engine and hydraulic crane controls are all designed to enable the crane to perform the following functions in concert:
>
> Slew (rotate) left and right;
> Boom raise and lower;
> Main hoist raise and lower;
> Auxiliary hoist raise and lower
>
> All of these functions are custom to a specific crane and crane power design, as are all the safety devices and controls associated with them. Changing the prime mover of a crane would require the redesign and replacement of all associated functional equipment and controls, which comprise the majority of what a crane physically is, thereby making this not feasible."

[24] Noble Drilling (U. S.) LLC, Garth Pulkkinen, Operations Manager-Alaska, e-mail to Rodger Steen and Jim Miller, November 26, 2012.

Region 4 EPA has made a similar determination in 2011 for drill rig crane engines whereby engines designed specifically for marine cranes did not meet Tier 3 standards, and that replacement of the engines would require significant crane modification and thus, it was technically infeasible to replace only the engines.[25] The existing Tier 1 engines were determined to be acceptable.

Noble concludes for the reasons noted above, that to replace the crane engines involves replacing the engine and entire crane structure. The estimated capital cost for this replacement scope is $10.4 million.[26] This includes purchasing, shipping, and installing the engines, lease of drill ship during transport and Seattle shipyard time, and shipyard time in Seattle. Noble bases these estimates on its 2011 and 2012 experience making modifications to the Discoverer drillship. The cost breakdown is provided in Table 5-3.

Table 5-3: Cost for crane engine replacement

Cost Item	Cost (million $)
Purchase two Liebherr MTC-1900-50 cranes[a]	4.4
Shipping of cranes (from Austria)	0.5
Removal of existing cranes and pedestals	1.5
Fabricate and installation pedestals	2.0
Install new cranes	2.0
Total	**10.4**

[a] matched engine & structure

Shell estimates the maximum use of the Discoverer drillship in the Arctic Ocean to be 5 years.[27] So without consideration for cost of money or annual expenses, the annualized cost for crane engine replacement will be at approximately $2.1 million.

New technology engines are category C1, Tier 2 marine CI engines and the emission factor limits are listed in Table 5-4. Even if the new engines were to operate at capacity for the full permitted 120 days per year, the emission reduction from engine replacement would be small, as shown in Table 5-4. Based on the small annual emission reduction, the cost of engine replacement would be range from $390,000 per annual ton of NOx removed to $4.3 million per annual ton of PM removed. Engine replacement would not reduce CO emissions. All of these costs are well above a reasonable BACT cost effectiveness criterion. Engine replacement, therefore, is not BACT for the crane engines.

[25] Region 4 EPA "Preliminary Determination and Statement of Basis, Outer Continental Shelf Air Permit OCS-EPA-R4007". http://www.epa.gov/region4/air/permits/ocspermits/eni/Eni_PD_SOB_8_31_2011.pdf

[26] Noble Drilling (U. S.) LLC, Garth Pulkkinen, Operations Manager-Alaska, e-mail to Rodger Steen, November 9, 2012. "Cost detail for hypothetical crane changeout on Discoverer"

[27] From Jim Miller (Shell Operations) through Keith Craik, e-mail October 26, 2012

Table 5-4: Combined Crane Emissions and Cost of Emission Reduction using new-technology engines (@ 545 kW)						
Pollutant	**Current BACT Limits[a] (with CDPF) (g/kWh)**	**Existing Engines Without CDPF Limits[b] (g/kWh)**	**Current Technology Engines[c] (g/kWh)**	**Difference between Existing and Current Technology (g/kWh)**	**Annual Emissions Existing Engines without CDPF (tpy)**	**Cost per ton removed**
PM	0.072	0.48	0.20	0.28	0.48	$4,330,000
NOx	10.3	10.3	7.2	3.1	5.35	$390,000
CO	0.22	2.18	5.0	0	0	---
VOC	0.064	0.64	---	< 0.64	< 1.1	> $1,900,000

[a] Permit Conditions H.2, page 41
[b] Current limits removing the 85% PM control and the 90% CO & VOC control for CDPFs
[c] Marine Category C1, Tier 2 emissions

Cementing Unit Engine Replacement Cost Analysis

Current technology nonroad engines of the size used with the cementing units (130 to 450 kW) is defined by the Tier 4i emission standards. Shell leases its cementing skid, and has selected Halliburton because of its particular expertise in cementing. Halliburton only leases two designs of marine cementing skids, neither of which use Tier 4i engines for safety reasons; Tier 4i engines are technologically infeasible because they are located in close quarters and have a higher exhaust temperature than lower tier engines. To use these engines safely, Halliburton states they must lower the exhaust temperature by water cooling, which is not feasible on drill ships[28]. Tier 3 is the most current technology that could be used. Halliburton does not carry cementing skids with Tier 3 engines so if Shell is to use them, Shell would need to replace the engines at its expense.

Cost for replacement of the two cementing engines is estimated at $457,000, as shown in Table 5-5. This includes purchasing, shipping, and installing the engines, which is considered possible without travel to a shipyard. Shell estimates the maximum use of the Discoverer drillship in the Arctic Ocean to be 5 years. So without consideration for cost of money or annual expenses, the annualized cost for crane engine replacement will be at approximately $91,400.

The newest- technology engines, feasible for use on the Discoverer are categorized as Nonroad Tier 3. Table 5-6 summarizes emission factors associated with existing and new technology engines and the emission reduction achievable by replacing the existing (uncontrolled) cementing unit engines with new Tier 3 engines. Considering only the capital cost of purchase, shipping and installation, engine replacement would cost $16,380 per annual ton of NOx avoided, $110,120 per annual ton of PM avoided, and $304,666,000 per annual ton of CO

[28] Halliburton Technology, e-mail from Billy Coskrey to Ronnie Holubec November 13, 2012, “C9 Tier III Engine”

avoided. All of these costs are well above a reasonable BACT cost effectiveness criterion. Engine replacement, therefore, is not BACT for the cementing unit engines.

Table 5-5: Cost for Cementing Engine Replacement

Cost Item	Cost ($)
Engine package (Caterpillar C9) & associated parts	300,000
Modifications for engine package to accept Cat C9	35,000
Removal of Detroit 8V71 engine package	36,500
Installation of C9 package	61,500
Materials Transportation	14,000
Personnel Transportation	10,000
Total	**457,000**

Table 5-6: Cementing Engine Emissions and Cost Effectiveness Analyses

Pollutant	Current BACT Limits[a] (with CDPF) (g/kWh)	Existing Engines Without CDPF Limits[b] – (g/kWh)	Current Technology Engines[d] (g/kWh)	Difference between Existing and Current Technology (g/kWh)	Annual Emissions Existing Engines without CDPF (tpy)	Cost per ton removed[f]
PM	0.253	1.67	0.20	1.39	0.83	$110,120
NOx	13.2	13.3[c]	4.0[e]	9.3	5.58	$16,380
CO	0.40	4.0	3.5	0.5	0.30	$304,666
VOC	0.20	2.0	---	< 2.0	< 1.2	> $76,167

[a] Permit Conditions H.2, page 41
[b] Current limits removing the 85% PM control and the 90% CO & VOC control for CDPFs
[c] Stack-test maximum emission factor from the two cementing unit engines
[d] Nonroad Tier 3 emissions
[e] Includes NOx and HC
[f] Based on permit limit of 320 gal/day (Condition I.7.2) and 120 days per year

5.2 Request to Increase the Crane and Cementing Unit Engines Hourly NOx Mass Emission Limit

The Permit requires that the two crane engines and two cementing unit engines comply with hourly NOx emission limits that were derived using the assumption that the hourly crane and cementing use rates would be the same as hourly average of the 24-hour use rate. Shell maintains that the duty over a day is appropriate, but 2012 operating experience revealed that the crane engines must occasionally operate at higher than these averages over one hour, and Shell anticipates that the cementing units will experience the same hourly need. This section provides the basis for a request to increase the hourly NOx mass emissions limit to reflect a higher hourly use rate.

5.2.1 Background

The Permit requires that NOx and PM emissions from the crane and cementing engines be calculated using source test-based emission rates and measured fuel usage. There were eight occasions when the hourly fuel consumption by the crane engines was high enough to indicate that the hourly NOx mass emission limit (2.48 lb/hr) was exceeded. Consequently, Shell submitted excess emission reports when the hourly NOx emission limit was indicated to be exceeded by the crane engines. These reports accounted for 21 percent of all excess emission and permit deviation reports submitted for the Discoverer and Associated Fleet during the 2012 drilling season. Table 5-7 presents the dates of these eight events and calculated hourly NOx emissions based on source test-based emission factors and fuel consumption.

Table 5-7: Hourly NOx Mass Emission Limit Exceedance Events for Cranes

Date/Time	Calculated NOx emissions (lb/hr)	Percent of Limit
10/6/2012 1:00	2.86	115%
10/7/2012 10:00	2.98	120%
10/9/2012 12:00	2.59	104%
10/12/2012 2:00	2.90	117%
10/15/2012 7:00	3.26	131%
10/15/2012 13:00	2.69	108%
10/16/2012 2:00	2.70	109%
10/17/2012 1:00	2.78	112%

[a] Permit limit (Condition H.5.1) limits aggregate hourly NOx to 2.48 lb/hour

The basis for calculating emissions from the cranes in the 2010 permit application was the assumption that only one engine would operate at a time and the operating engine would operate at only 40 percent of the engine's rated capacity. Shell requests that the Permit be revised to allow both cranes to operate simultaneously at their rated capacity, which will increase potential hourly mass emissions of all pollutants emitted by the crane engines. Longer term (daily and annual) fuel consumption and emissions will not change. This emissions increase is in addition to the increase in emission factors resulting from removal of the CDPFs, as discussed in Section 5.1.

While there have been no exceedances of the one-hour cementing unit NOx emission limit, in part because of the low usage of the cementing unit, Shell anticipates use and NOx emissions higher than allowed by Permit Condition I.5.1.

Section 5.3 identifies proposed new NOx limits for the crane and cementing engines.

5.2.2 Relevant PSD Permit Conditions for NOx

As discussed in Section 5.1, the Permit specifies BACT limits for NOx, PM, CO, and VOC emissions from the crane engines. In addition, the permit limits hourly and annual NOx mass emissions and daily PM10 and PM2.5 mass emissions, and annual fuel consumption. In order to allow for the higher hourly duty cycle for cranes necessary for exploratory drilling, only Condition H5 needs to be revised. That condition currently reads:

H. 5. Hourly Emission Limits. Emissions from both deck cranes engines (Units FD-14 – 15) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

5.1. NOX: 2.48 lbs/hour

I. 5. Hourly Emission Limits. Emissions from all cementing unit and logging winch engines (Units FD-16 - 20) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

5.1. NOX: 6.56 lbs/hour

5.2.3 Efforts to Achieve PSD Permit Conditions

In an effort to comply with the hourly NOx emission limit in Condition H.5, Shell implemented procedures to operate the crane engines at the reduced duty cycle anticipated in the permit application. These measures included advising the crane operators to use only one crane at a time and to operate the cranes as intermittently as possible over the course of an hour. It became clear, however, that this operating practice was not conducive to effective drilling operations.

5.2.4 Proposed Permit Revisions Relevant to Crane and Cementing Unit Duty Cycle

Shell requests that the Permit recognize the higher duty requirements for the cranes and increase the hourly NOx emission rate from 2.48 to 12.40 pounds.

Reflecting the higher anticipated duty for the cementing engines, Shell anticipates that NOx emissions could be higher than allowed by Permit Condition I.5.1. The current limit of 6.56 lb/hr is based on an hourly average rate of 13.33 gallons (320 gallons per day divided by 24 hours). Shell requests raising the hourly fuel consumption expectation to 80 percent of combined engine capacity, which is 28.6 gallons per hour. Applying 80 percent load (400 kW) to the BACT emission rate of 13.155 g/kWh yields a one-hour NOx limit of 11.59 lb/hr.

5.3 Request for Option to Replace the Crane and Engine

Shell is continually evaluating its drilling equipment and practices to improve safety and efficiency. One change that may be desirable from an operations perspective is a replacement of the cranes, including both the structures and the associated engines. Shell requests the option to remove the existing cranes and install new cranes, subject to conditions. This replacement option would be limited to an 18-month period following issuance of a revised permit, unless a longer period of time for construction is allowed by EPA, in which case the option would terminate at the end of the longer period.

Shell would limit this replacement engine option to engines with emissions meeting the proposed BACT for the current engines, which are Marine CI engines, Category C1, Tier 2. The engines would also meet the proposed mass emission limits that reflect removal of the CDPFs and the crane duty cycle changes discussed in Sections 5.1 and 5.2.

5.3.1 BACT Analysis for Replacement Crane

The BACT analysis for the crane engines in Section 5.1.3 concludes that it would not be cost effective, for BACT purposes, to replace the crane engines. If for operational considerations, Shell concludes that crane replacement is needed, then Shell would install current-technology engines.

The crane engines meet the definition of "marine engines" in EPA's emission regulations for compression-ignition marine engines because they are permanently installed and are an integral part of the Discoverer.[29] Current technology for marine engines of this size (up to 5 liters/cylinder) is Category C1, Tier 2, with emission limits of 7.2 g/kW-hr NOx and HC, 0.2 g PM/kW-hr, and 5.0 g CO/kW-hr.

BACT for replacement crane engines is

- GCP
- use of ULSD
- use of low-sulfur lubricants
- use of Marine Category 1, Tier 2 engines

5.3.2 Proposed Permit Revisions Relevant to Crane Replacement

It is not clear whether Table 1 of the existing Permit limits Shell to the listed engine model or horsepower. Shell requests that the Permit be clarified to allow Shell the option to replace the cranes with engines that meet the BACT limits, the existing daily PM and annual NOx mass emission limits, and the higher hourly NOx limit proposed in Section 5.5.

5.4 Proposed Permit Revisions

5.4.1 Proposed Permit Revisions Relevant to Removing CDPFs

In Section 5.2, Shell proposes changes in PM, CO, and VOC BACT emission limits (g/kWh) for the cranes and cementing unit engines due to removal of the CDPFs. NOx emissions (g/kWh) would not be affected by removing the CDPFs and no change to the NOx BACT limit for crane engines is proposed. The proposed revised emission limits for the crane engines result from eliminating the assumed CDPF emission reduction, which was 85 percent for PM and 90 percent for both CO and VOC.

The current crane-related conditions in Permit section H that Shell proposes to revise as a consequence of removing the CDPFs are as follows:

> ~~1. Operation of Catalyzed Diesel Particulate Filter (CDPF). At all times that any of Units FD-14 – 15 in operation, the exhaust from each Unit shall be directed to an operating CleanAIR Systems CDPF, Part No. 07040401AF.~~

[29] 40 CFR 94.2 (b): ***Marine engine*** means a nonroad engine that is installed or intended to be installed on a marine vessel. This includes a portable auxiliary marine engine only if its fueling, cooling, or exhaust system is an integral part of the vessel.

~~1.1. Each CDPF shall be equipped with an operating HiBACK monitor and alarm unit, that records exhaust pressure and temperature.~~

~~1.2. During each day that each of Units FD-14 -15 is operated, the exhaust temperature shall be above 300oC, or 572oF, for at least 30 percent of the time.~~

2. BACT Limits. Emissions from each deck crane engine (Units FD-14 – 15) shall not exceed the emission limits specified for each of the pollutants below:

2.2. PM: ~~0.0715~~ 0.48 g/kW-hr

2.3. PM10: ~~0.0715~~ 0.48 g/kW-hr

2.4. PM2.5: ~~0.0715~~ 0.48 g/kW-hr

2.6. CO: ~~0.220~~ 2.2 g/kW-hr

2.7. VOC: ~~0.0640~~ 0.64 g/kW-hr

6. Daily Emission Limits. Emissions from both deck crane engines (Units FD-14 – 15) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

6.1. PM10: ~~0.41~~ 2.75 lbs/day

6.2. PM2.5: ~~0.41~~ 2.75 lbs/day

9. Monitoring, Recordkeeping, and Reporting. The permittee shall:

~~9.5. Monitor and record the exhaust temperature of each engine by use of the HiBACK monitor and alarm unit, while the engine is in operation.~~

~~9.6. Each day, calculate and record for the previous calendar day, the percent of operational time for each engine that the exhaust temperature was above 300oC (572oF).~~

The current cementing engine-related conditions in Permit section I that Shell proposes to revise as a consequence of removing the CDPFs are as follows:

~~1. Operation of Catalyzed Diesel Particulate Filter (CDPF). At all times that any of the cementing unit and logging winch engines (Units FD-16 – 20) are in operation, the exhaust from each emission unit shall be directed to operating CleanAIR Systems CDPF, Part No. FDA300 for Units FD-16 and 17, Part No. FDA225 for Unit FD-18, and as specified by CleanAIR Systems for Units FD-19 - 20.~~

~~1.1. Each CDPF shall be equipped with an operating HiBACK monitor and alarm unit, that records exhaust pressure and temperature.~~

~~1.2. During each day that each of Units FD-16 – 20 is operated, the exhaust temperature shall be above 300oC, or 572oF, for at least 30 percent of the time.~~

2. BACT Limits. Emissions from each of Units FD-16 – 20 shall not exceed the emission limits specified for each of the pollutants below:

2.2. PM:

FD-16 ~~0.253~~ 1.69 g/kW-hr

FD-17 ~~0.253~~ 1.69 g/kW-hr

2.3. PM10:

FD-16 ~~0.253~~ 1.69 g/kW-hr

FD-17 ~~0.253~~ 1.69 g/kW-hr

2.4. PM2.5:

FD-16 ~~0.253~~ 1.69 g/kW-hr

FD-17 ~~0.253~~ 1.69 g/kW-hr

2.6. CO:

FD-16 ~~0.40~~ 4.0 g/kW-hr

FD-17 ~~0.40~~ 4.0 g/kW-hr

2.7. VOC:

FD-16 ~~0.20~~ 2.0 g/kW-hr

FD-17 ~~0.20~~ 2.0 g/kW-hr

6. Daily Emission Limits. Emissions from all cementing unit and logging winch engines (Units FD-16 – 20) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

6.1. PM10: ~~3.87~~ 16.88 lbs/day

6.2. PM2.5: ~~3.87~~ 16.88 lbs/day

~~10. Monitoring, Recordkeeping and Reporting. The permittee shall:~~

~~10.5. Monitor and record the exhaust temperature of each of engines FD-16 - 20 by use of the HiBACK monitor and alarm unit, while the engine is in operation.~~

~~10.6. Each day, for each of engines FD-16 - 20, calculate and record for the previous calendar day, the percent of operational time for each engine that the exhaust temperature was above 300°C (572°F).~~

5.4.2 Proposed Permit Revisions Relevant to a Higher Hourly Use

In order to accommodate the requested increase in hourly duty for the cranes and cementing unit engines, Shell proposes the following changes in the Permit:

H. 5. Hourly Emission Limits. Emissions from both deck cranes engines (Units FD-14 – 15) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

5.1. NOX: ~~2.48~~ 12.4 lbs/hour

I. 5. Hourly Emission Limits. Emissions from both cementing unit engines (Units FD-16 – 17) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

5.1. NOX: ~~6.56~~ 11.6 lbs/hour

As discussed in prior sections, Shell does not propose any changes to the annual NOx emission limit or fuel consumption limit that are established in Conditions H.4 and H.7.

5.4.3 Proposed Permit Condition Authorizing Crane Replacement

Shell requests that the Permit be clarified to allow Shell the option to replace the cranes with engines that meet the Marine CI Engine, Category C1 Tier 2 engine family emission requirements. If EPA believes it necessary to include explicit permit conditions for the Category C1, Tier 2 engines, the following text may be appropriate:

Deck Crane Alternative. The permittee may elect to replace the deck cranes (FD-14 and FD-15), in which case the cranes shall meet the following limits:

BACT Limits. Emissions from each deck crane engine (Units FD-14 – 15) shall not exceed the emission limits specified for each of the pollutants below:

NOx and NMHC: 7.2 g/kW-hr

PM: 0.2 g/kW-hr

PM10: 0.2 g/kW-hr

PM2.5: 0.2 g/kW-hr

CO: 5.0 g/kW-hr

Compliance with emissions limits shall be demonstrated by purchasing and installing engines certified to meet Marine CI Engine, Category C1, Tier 2 engine family emission requirements.

5.5 Compliance with Ambient Air Quality Standards and PSD Increments

This revision application includes several changes that affect emissions, so a dispersion modeling analysis addressing the net effect of all changes is included in Appendix D. That analysis confirms that the emission increases from the Discoverer and its associated fleet resulting from the requested revisions for crane and cementing unit engines will not cause or contribute to violations of ambient air quality standards or PSD increments.

6 Request to Revise Conditions that Apply During Engine Startup Periods

Certain emission limits originally proposed by Shell, and incorporated into the Permit, failed to take into account the fact that engine exhaust must be hot for catalytic controls to achieve expected emissions reductions. The Permit specifies catalytic control technologies and related operating requirements for many of the Discoverer and Associated Fleet emissions units. For particulate matter, carbon monoxide, and VOC emissions, the Permit specifies either oxidation catalysts or catalytic diesel particulate filters (CDPF), depending on the engine. For NOx emissions, the Permit specifies selective catalytic reduction (SCR) for some engines. Each of these types of catalyst must be operated above certain temperature thresholds to effectively reduce emissions. The time necessary to reach the required operating temperature depends on the engine type, its size, its application, the size of the control device, ambient temperature, and the load imposed on the engine during the startup period. Operations during the 2012 season confirmed that engines with catalytic controls were unable to meet emission limits during startup periods, and because the Permit does not recognize this reality, Shell had to submit numerous deviation and excess emissions reports.

In recent emission standard rulemaking for compression ignition internal combustion (IC) engines, EPA acknowledged the fact that catalytic controls are not effective during startups and concluded that it is not feasible to prescribe a numerical emission standard for IC engines during startup periods. Based on its recent operational experience and EPA's conclusions for IC engines during startup, Shell proposes that BACT during engine startup is good operating practices and minimizing the time it takes to safely achieve normal operating temperature.

6.1 Background

6.1.1 Required Catalytic Control Devices

Table 6-1 presents the Permit-required and installed catalytic control devices for each applicable combustion unit. As discussed in Chapter 3 of this application, several emission units were equipped with better performing CDPF instead of oxygen catalysts.

Table 6-1: Required Catalytic Control Devices for the Discoverer and Associated Fleet

Emission Unit	Emission Unit ID	Permit-required Emission Controls	Installed Emission Controls
Generator Engine	FD-1-FD-6	SCR, OxyCat, CCV	E-POD (SCR, CDPF), CCV
MLC Air Compressor	FD-9	OxyCat	CDPF
MLC Air Compressor	FD-10, FD-11	OxyCat	OxyCat
HPU	FD-12, FD-13	CDPF, CCV	CDPF, CCV
Crane Unit	FD-14. FD-15	CDPF, CCV	CDPF, CCV
Cementing Unit	FD-16, FD-17	CDPF, CCV	CDPF, CCV
Fennica/Nordica Propulsion Engine	F-1,2,3,4	SCR, OxyCat, CCV	SCR, OxyCat, CCV
Tor Viking Propulsion and Generator	TV-1 - TV-6	SCR, OxyCat, CCV	SCR, OxyCat, CCV

Table 6-1: Required Catalytic Control Devices for the Discoverer and Associated Fleet			
Emission Unit	**Emission Unit ID**	**Permit-required Emission Controls**	**Installed Emission Controls**
Nanuq Propulsion and Generator	N-1 – N-4	CDPF	CDPF

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6.1.2 Catalytic Control Device Startup Deviation Reports

To confirm that catalyst-based control equipment is operating properly, the Permit requires Shell to measure exhaust gas temperature at the inlet to the control device every 15 minutes. If the exhaust gas temperature at the inlet to an SCR unit is less than 250°C or the exhaust gas temperature at the inlet to an oxidation catalyst or CDPF is less than 300°C, Shell must submit a deviation report and apply "uncontrolled" emission rates in the monitoring reports for the low temperature time period – even though direct measurement of hourly NOx during that period could result in an actual amount of emissions less than what was required to be reported.

The Permit conditions do not take into account the fact that engines are cold before startup and that it takes time for the engine and exhaust to reach an elevated operating temperature. During the 2012 season Shell had to submit numerous deviation and excess emissions reports due to low engine exhaust temperatures during startup of an engine. In most cases, low temperatures required deviation reports for not having urea flow because the E-POD controller does not allow urea injection until the temperature is high enough for effective reaction.

Shell submitted 14 excess emission reports as a result of operation during startup periods, accounting for 42 percent of all excess emission and permit deviation reports submitted for the Discoverer and Associated Fleet during the 2012 season. Table 6-2 presents the excess emission and permit deviation reports submitted as a result of startup periods. In addition, Shell identified 312 fifteen-minute low temperature or no-urea flow permit deviations for units monitored by CMS, and 85 daily permit deviations from units installed with HiBACK monitoring systems that occurred during periods of startup. These permit deviations are reported in the consolidated monthly permit deviation reports for the months of September and October 2012.

Shell seeks a revision that would avoid engine startup necessarily resulting in repeated unavoidable deviation reports. As discussed below, sound technical reasons and documented regulatory determinations support providing a basis for relief during startup from emission limits based on controls that require engines to come up to temperature to effectively control emissions. The requested revision would also reduce the significant administrative burden on both Shell and EPA.

Table 6-2: Catalytic Control Device Startup Deviation Reports			
Vessel	**Emission Unit(s)**	**Type of report**	**Date of Deviation**
Tor Viking	TV-1,2,5,6	Both	9/24/2012
Discoverer	FD-1, FD-4	Both	9/25/2012
Tor Viking	TV-1, 2, 4	Both	9/26/2012

Table 6-2: Catalytic Control Device Startup Deviation Reports			
Vessel	**Emission Unit(s)**	**Type of report**	**Date of Deviation**
Tor Viking	TV-2	Both	9/28/2012
Discoverer	FD-4 - FD-6	Both	10/1/2012
Discoverer	FD-1 - FD-6	Both	10/2/2012
Discoverer	FD-1 - FD-6	Excess Emissions	10/3/2012
Discoverer	FD-1 - FD-6	Excess Emissions	10/3/2012
Discoverer	FD-2, 4, 6	Excess Emissions	10/4/2012
Discoverer	FD-2, 4, 6	Excess Emissions	10/5/2012
Discoverer	FD-2, 4, 6	Excess Emissions	10/5/2012
Discoverer	FD-1 - FD 6	Excess Emissions	10/10/2012
Discoverer	FD-1 - FD-6	Excess Emissions	10/18/2012
Discoverer		Excess Emissions	9/30/2012
Discoverer and Associated Fleet	Multiple	Permit Deviation	9/6-9/30/12
Discoverer and Associated Fleet	Multiple	Permit Deviation	10/1-10/31/12

6.2 PSD Permit Limits

Permit conditions relevant to operation of the engines during startup include:

B.13 ***Good Operating and Maintenance Requirements.*** *At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate each emission unit, including any associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The permittee shall keep records of any maintenance that would have a significant effect on emissions (the records may be kept in electronic format) and keep a copy of either the manufacturer's or the operator's maintenance procedures.*

B 14.7 Report as a deviation under Condition A.0 any periods during which the urea pump is not operating, the inlet temperature is less than 250°C, or the NOX concentration is 150 percent or more than the NOX concentration measured during the most recent previous source test that produced compliance data or emission factors for this permit.

B 15.7 Report as a permit deviation under Condition A.17.3 any periods during which the inlet temperature is less than 300°C, or the CO concentration is 120% or more than the CO concentration measured during the most recent previous source test that produced compliance data or emission factors for this permit.

Shell proposes that the requirement for good operating practices as established in Condition B.13 be retained. As discussed in Chapter 6.5, Shell proposes that Conditions B14.7 and B15.7 be revised to remove the requirement to report as a permit deviation the low temperatures (and related lack of urea injection) that occur during startup.

6.3 Efforts to Achieve PSD Permit Limits

In an effort to achieve exhaust gas temperatures quickly and to minimize the need to file deviation reports under Conditions B14.7 and B15.7 due to startups, Shell implemented several engine operational changes during the 2012 drilling season:

- Early season practice was to limit the total load on a given generator to about 600 kW to confirm that maximum generation capacity of each engine (800 kW) was never exceeded. The issue with this approach was that as generators were added to the system to address additional power needs, all would tend to drop to 400 kW or below until load or demand increased even further. Operating generators at 400 kW or below yielded exhaust temperatures less than the desired 300°C. After careful review and consideration of safety, operating procedures on the vessel were changed to permit generators to run at higher average loads (600 – 700 kW) before additional generators were brought on line. This change resulted in average loads, and therefore average exhaust temperatures, higher and more consistently above 300°C.
- Additional computer displays with color coded alarms were strategically located to better manage generator loads and exhaust temperatures.
- Forms were added to the process to confirm that vessel personnel periodically monitor and record critical parameters.
- Shell arranged for an NC Machinery technician trained in EPOD operation and repair to remain on the Discoverer for the majority of the drill season to confirm that the engines and control device systems were running correctly, promptly identify if engine performance deviated from required levels, and work on solutions to address performance issues as they arose

Shell will install electronic preheaters to Units FD-1-6 prior to the 2013 drill season to further reduce the time necessary for low temperature startup.

6.4 BACT Re-evaluation

Emissions from reciprocating engines have been regulated under the Clean Air Act for decades. However, Shell's research has revealed virtually no emission limits that apply during startup and shutdown of reciprocating engines.

EPA established two federal rules that regulate stationary compression ignition internal combustion engines: National Emission Standards for Hazardous Air Pollutants: Stationary Reciprocating Internal Combustion Engine Requirements Subpart ZZZZ ("Subpart ZZZZ") and New Source Performance Standards: Stationary Compression Ignition Internal Combustion Engine Requirements Subpart IIII ("Subpart IIII") in 40 CFR 63 and 40 CFR 60, respectively.

These rules were developed to limit previously unregulated engines to the same standards established for comparable non-road and marine engines. In Subpart ZZZZ, EPA recognized and took into account the fact that reciprocating engines must be treated differently during startup periods.

Subpart ZZZZ regulates emissions of hazardous air pollutants (HAP) for new and existing engines of all sizes, and was first promulgated in 2004. The rule defines startup for stationary engines with catalytic controls as "the time from initial start until applied load and engine and associated equipment reaches constant load, or normal operation, including the catalyst" - 40 CFR § 63.6675. The 2004 rule required compliance with numerical emissions limits and work practice standards, "except during periods of startup, shutdown, and malfunction (SSM)" 40 CFR § 63.6605(a) (2004 version). The rule did require that owners "operate and maintain your stationary RICE, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction" 40 CFR § 63.6605(b) (2004 version).

On December 19, 2008, the U.S. Court of Appeals for the District Columbia Circuit vacated the SSM exemption in 40 CFR Part 63, subpart A. The decision required EPA to implement standards that apply at all times, including during SSM periods. In 2010, EPA finalized an updated version of the rule which includes standards that apply during startup. During the rule development, EPA received extensive comments on the proposed startup requirements. Based on the comments, industry provided information, and review of technical data, EPA determined that "it is not feasible to prescribe a numerical emission standard for stationary CI engines during periods of startup because the application of measurement methodology to these engines is not practicable due to technological and economic limitations." Preamble 2010 Final Rule, EPA–HQ–OAR–2008–0708, FRL–9115–7.

In its response to comments, EPA cited the following reasons for the determination:

- The emissions from stationary CI engines during startup are significantly different than the emissions during normal operation. During startup, incomplete combustion of the diesel fuel causes variations in the pollutant concentrations and fluctuations in the flow rate of the exhaust gas. Incomplete combustion is due to cold areas of the cylinder walls that cause the temperature to be too low for efficient combustion. As the engine continues to operate, these cold regions begin to heat up and allow for more complete combustion of the diesel fuel and stabilization of the exhaust flow rate and pollutant concentrations. In addition, the engine experiences extreme transient conditions during startup, including variations in speed and load, poor atomization of the fuel injection, which leads to variable engine and engine exhaust temperatures, variable exhaust gas flow rates, and variable diluent pollutant concentration.
- EPA test methods (e.g., 40 CFR part 60, appendix A, Methods 2, 3A, 4, and 10) do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods. The innate and substantial changes in the engine operations during startup operations create rapid variations in exhaust gas flow rate as well as changes in both pollutant and diluent gas concentrations. Correlating the exhaust gas flow rates and the gas components concentration data for each fraction of

time over the entire period of a startup operation is necessary to apportion the values appropriately and to determine representative average emissions concentrations or total mass emissions rate.

- Measuring flow and concentration data in the types of rapidly changing exhaust gas conditions characteristic of stationary CI engines is unachievable with current technologies applicable to stack emissions testing. For example, application of Method 2 to measure stack flow rate requires collecting data for velocity pressure and stack temperature at each of 12 traverse points and a corresponding stack moisture and oxygen concentration (for molecular weight determination). This traverse operation requires about 30 minutes to complete in order to produce a single value for the test period, which is approximately the same amount of time as the engine startup period. Clearly a single flow rate value would not sufficiently represent the variable flow conditions nor allow appropriate apportioning of the pollutant concentration measurements over that same period for calculating a representative average emissions value. Even if the start-up period is longer than 30 minutes, the stack flow rate test period could not be short enough to represent the short term (e.g., minute- by-minute) result necessary for representative emissions calculations.
- Based on information reviewed by EPA, engine startup typically requires no more than 30 minutes. EPA received comments saying that there are conditions where it may take more than 30 minutes to startup the engine, for example for cold starts or where the ambient conditions are very cold. But EPA chose to limit startups to 30 minutes on the basis that commenters did not provide sufficient specificity or data to determine whether any scenarios were appropriate to allow a longer startup period.
- EPA requested certain information from the Engine Manufacturers Association (EMA) to make their determination. EMA provided the following to EPA in a letter dated February 17, 2009, “The temperature that must be reached for effective catalyst-based aftertreatment varies and depends on the type of catalyst and after-treatment system that is used to reduce emissions. That target temperature also varies greatly by pollutant, with some HAPs being controlled at the low end of the temperature scale and others requiring a higher temperature before they can be effectively controlled.”

For these reasons, EPA promulgated operational standards specifying that owners and operators “must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply.” 40 CFR § 63.6625(h).

Shell has determined, based on temperature data collected throughout the 2012 drilling season, that for engines equipped with catalytic control devices, startup can be completed within 30 minutes approximately 85 percent of the time. However, due to the severely cold ambient temperatures in the Arctic, approximately 15 percent of startups can take between 30 and 60 minutes to complete.

Subpart ZZZZ recognizes that there may be situations for which an alternative management practice, such as an extended startup period, may be warranted and so allows sources to work

with their permitting authority to have an alternative practice approved. Further, EPA has recognized that the inability to meet limits due to startup may extend beyond 30 minutes.

In a 2011 determination letter EPA said that it "reads the 30 minute limit for engine startup as referenced in Tables 1a, 2a, 2c, 2d, and 40 CFR 63.6625(h) to not exclude startup operations beyond the 30 minute limit. Instead, the 30 minute of startup is a period when the numerical emission limitations under normal operation do not apply." April 25, 2011 letter to Northern Natural Gas, from EPA Region 7, in consultation with EPA Office of Air Quality Planning and Standards, Office of General Counsel, and Office of Compliance. The letter further acknowledges that "conditions may arise where an engine cannot instantaneously meet an emission limit, such as immediately following 30 minutes of startup," which is the reason that Subpart ZZZZ requires compliance with numerical limits on a 3-hour block average or 4-hour rolling average, depending on the limit.

The regulation is written with the understanding that startups are not necessarily limited to 30 minute periods. Consequently, compliance is demonstrated in a way that will not lead to violations during normal startups that may, due to outside factors such as severely cold ambient temperature, extend longer than 30 minutes. Therefore, even if an engine exceeds the emission limit immediately after the 30 minute startup period, it is likely that the emissions averaged across the 3- or 4-hour period, will not result in an exceedance of the emission limit, as applicable. Because the Permit requires that temperature readings are taken every 15 minutes during operation, the intent of the regulation that the permittee is not penalized if a startup extends for longer than 30 minutes would not apply to Shell because each 15-minute period of low temperature beyond 30 minutes would result in a permit deviation. Therefore, Shell requests that startup be defined as the time from initial start until applied load and engine and associated equipment reaches constant load, or normal operation, including the catalyst, not to exceed one hour.

While Subpart IIII does not contain any requirements for startup operation, its provisions reflect the fact that stationary compression ignition engines must be warm to achieve the standards. The Subpart regulates emissions of NOx, PM, SO2, CO, and hydrocarbons from stationary compression ignition internal combustion engines. The responsibility of demonstrating compliance with the Subpart's emission standards is placed on manufacturers, who must conduct performance tests under prescribed test conditions to receive certification from EPA.

Manufacturers must certify their engines to the tiered standards in place for nonroad engines. When certifying Tier 1, 2, and 3 standard engines, manufacturers must measure exhaust emissions using the testing procedures in 40 CFR Part 89 Subpart E. The procedure includes the following steps:

- Allow a minimum of 30 minutes warmup in the standby or operating mode prior to spanning the analyzers. 40 CFR § 89.406(a).
- Precondition (warm up) the engine in the following manner:
    - For variable-speed engines:
        - Operate the engine at idle for 2 to 3 minutes;

- Operate the engine at approximately 50 percent power at the peak torque speed for 5 to 7 minutes;
- Operate the engine at rated speed and maximum horsepower for 25 to 30 minutes. 40 CFR § 89.407(c)(5).

- Start the test cycle within 20 minutes of the end of the warmup. A mode begins when the speed and load requirements are stabilized to within the requirements of § 89.410(b). A mode ends when valid emission sampling for that mode ends. For a mode to be valid, the speed and load requirements must be maintained continuously during the mode. Sampling in the mode may be repeated until a valid sample is obtained as long the speed and torque requirements are met. 40 CFR § 89.407(c)(7).

As stated above, manufacturers only test engines during steady-state operation; therefore, the guaranteed emission rates provided for certified engines are not representative of performance during startup. In fact, EPA recognizes, in the NSPS general provisions, that "operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard." 40 CFR § 60.8(c)

6.5 Proposed Permit Revisions

As explained in Section 6.4, EPA's actions in two rulemakings for internal combustion engines reflect the Agency's acknowledgment that Based on the analysis provided in Chapter 6.4, it is technically infeasible to achieve or demonstrate compliance with numerical emission limits during startup periods. It is no different for the engines subject to the Permit. Therefore, Shell proposes that BACT during engine startup is good operating practices and minimizing the time it takes to safely achieve normal operating temperature. Shell proposes to operate the engine and control device according to existing Permit condition B.13, which describes good operating and maintenance requirements. These standards are proposed only for periods of startup, up to one hour, after which the existing Permit BACT limits apply.

Shell also requests that the Permit be revised to eliminate the current requirements for filing excess emission and permit deviation reports during a reasonable startup period.

In order to implement the requested revisions, Shell proposes to revise B.14.7 and B.15.7 and add Condition B.16, as follows:

B.14.7 Report as a deviation under Condition A.0, except during engine startup periods as defined under Condition B.16, any periods during which the urea pump is not operating, the inlet temperature is less than 250°C, or the NOx concentration is 150 percent or more than the NOX concentration measured during the most recent previous source test that produced compliance data or emission factors for this permit.

15.7. Report as a permit deviation under Condition A.0, except during engine startup periods as defined under Condition B.16, any periods during which the inlet temperature is less than 300°C, or the CO concentration is 120 percent or more than the CO concentration measured

during the most recent previous source test that produced compliance data or emission factors for this permit.

B.16 **Catalytic Control Device Startup Provisions.** For any emission unit that is required by this permit to be controlled by an oxidation catalyst, a selective catalytic reduction (SCR) unit, or a catalytic diesel particulate filter (CDPF), the permittee shall operate and maintain the engine and control device as follows:

16.1 In lieu of the emission limits required during normal operation, the following standards apply during engine startup periods to the engines in Sections C, F, G, H, I, N, O, and Q. Engine startup periods are defined as the time from initial start until engine and associated control equipment reaches normal operating temperature, including the catalyst, not to exceed one hour:

16.2.1 The permittee shall minimize the duration of an engine's startup to a period needed for appropriate and safe loading of the engine, not to exceed one hour; and

16.2.1 Maintain and operate each emission unit, including the associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions, as required in Condition B.13 of this permit.

16.2 For emission units installed with CDPF that are equipped with an operating HiBACK monitor and alarm unit, temperature readings taken during startup, up to one hour from initial start, are excluded when determining compliance with the requirement that the exhaust temperature shall be above 300°C, or 572°F, for at least 30 percent of the time, on a daily basis.

Shell proposes to add the following language to Sections C, F, G, H, and I of the Permit:

C. 4 **BACT Work Practice Standards during Startup.** During engine startup periods, the permittee shall:

4.1 Minimize the duration of an engine startup to a period needed for appropriate and safe loading of the engine, not to exceed one hour; and

4.2 Maintain and operate each emission unit, including the associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions, as required in Condition B.13 of this permit.

6.6 Compliance with Ambient Air Quality Standards and PSD Increments

This revision application includes several changes that affect emissions, so a dispersion modeling analysis addressing the net effect of all changes is included in Appendix D. That analysis confirms that the emission increases from the Discoverer and its associated fleet will not cause or contribute to violations of ambient air quality standards or PSD increments.

7 Supply Ship Emission Controls

Elsewhere in this application Shell requests revisions that result in increasing potential fleet-wide PM emissions (increasing the Nanuq daily PM emissions limit discussed in Chapter 4 and operating crane and cementing engines without CDPFs discussed in Chapter 5). To offset these increases in potential emissions, Shell proposes to reduce the allowable daily PM emissions from the supply vessel while it is operating in dynamic positioning mode. This section identifies existing and proposed emission limits and how Shell intends to achieve compliance with the revised emission limits.

7.1 Permit Limits

The Permit subjects emission units on the vessels comprising the Associated Fleet to specific operational and emission limits that apply when the vessel operates within 25 miles of the Discoverer and the Discoverer is an OCS Source. The permit limits for the supply ships are based on Shell's permit application, which in turn was based on various estimates, assumptions, and information sources, including data from engine manufacturers.

Section P of the Permit sets aggregate limits that apply to the supply ship propulsion and generation engines for two operational modes: when in transit and when in dynamic positioning (DP) mode. The Permit sets an aggregate hourly NOx emission limit, aggregate daily PM10 and PM2.5 (collectively, PM) emission limits, and an aggregate daily fuel consumption limit. The propulsion and generator engines are not subject to BACT and are not required to install post combustion emission controls nor are emission controls necessary to meet the Permit emission limits.

As discussed below, Shell proposes to reduce the PM emission limits in Condition P.3 for the supply ship operating in DP mode. Condition P.3 currently reads:

> 3. Daily Emission Limits on Supply Ship in Dynamic Positioning Mode. Emissions from all generator and propulsion engines in aggregate on the supply ship shall not exceed the emission limits specified for each of the pollutants below:
>
> 3.1. PM10: 75.09 lbs/day
>
> 3.2. PM2.5: 75.09 lbs/day

7.2 Source Test Results and Permit Compliance

The Permit requires Shell to demonstrate compliance with the 75.09 lb/day PM limit using reference method source tests at a wide range of loads. Performance tests of the Harvey Explorer and the Harvey Spirit, two of the supply ships used in the Arctic in 2012, were conducted in spring 2012. The tests showed that PM emissions were much less than the PM emission rates used to predict supply ship emissions for the permit application. When considered with the daily fuel limit, the tests indicated compliance with Permit limits by wide margins.

In actual operation, compliance is routinely determined by multiplying fuel consumption by a source test-based emission factor. To determine whether lower PM emission limits could be

accepted for the Harvey Explorer and/or the Harvey Spirit, Shell analyzed actual DP events and determined that fuel use is roughly equal among the powering engines on the supply vessel during DP. Table 7.1 compares emission factors (lb/gal) derived from the average of source tests at different loads for each engine with the 0.0156 lb/gal emission factor used to develop the supply ship daily PM emi8ssion limit. Table 7-1 indicates PM emissions from either the Harvey Explorer or the Harvey Spirit are well below the allowable emission limits.

Table 7-1: Analysis of Supply Vessel Compliance with PM Emission Limits

Harvey Explorer		Harvey Spirit	
Emission Unit	**Actual/Allowable)***	**Emission Unit**	**Actual/Allowable***
HE-1	30%	HS-1	32%
HE-2	22%	HS-2	40%
HE-3	50%	HS-3	24%
HE-4	130%	HS-4	30%
HE-5	46%	HS-5	94%
HE-7	52%	HS-7	36%
HE-8	62%	HS-8	34%
HE-9	30%	HS-9	30%
Average	53%		40%

* Permit Condition P.3 is derived from a PM emission factor of 0.5 g/kWh, 133,100 Btu/gallon diesel heat content, and 9380 Btu/kWh heat rate for diesel engines. The percentiles in this Table are derived from the initial stack-testing-derived emission factors averaged over the power levels tested in units of g/kWh.

Another potential supply ship candidate for future seasons is a newly constructed vessel with Category C1, Tier 2 engines. In order to obtain Tier 2 certification, these engines are required to meet a PM emission limit of 0.2 g/kW-hr, which is only 40 percent of the rate used to determine the supply ship's allowable emission rate. Given that Shell does not propose to change the daily fuel limit, this vessel would also meet a lower daily PM emission limit.

7.3 Proposed Permit Revisions

Shell requests to lower the 24-hour PM emission limit for the supply ship in DP mode (75.09 lb/day) by 30%, to 56.2 lbs/day. As indicated above, both the Harvey Explorer and the Harvey Spirit can comply with this lower PM emission limit.

Shell also proposes that other vessels be authorized to serve as supply vessels as long performance testing confirms they can meet the emission limits and fuel consumption limit in the Permit. For such vessels, Shell would conduct required source testing according to the permit requirements and submit any notification as required under the permit.

However, if Shell selects a supply vessel whose engines are regulated by EPA as either Marine CI engines or Nonroad CI Engines, the emission limit associated with each associated engine classification would be sufficient evidence of the maximum actual engine emissions and no separate stack testing should be required.

Shell expects that its supply vessels will meet this reduced 24-hour PM emission allowance without tailpipe emission control. However Shell requests the option of meeting the allowance with a vessel using CDPFs, in which case, Shell will monitor the proper operation of that

emission control as described in other locations of the current permit. Specifically, it might install CDPF control on one or more engines and would operate the associated monitoring equipment as described under Section G for the HPU units..

7.3.1 Proposed Permit Limits

Shell proposes that the daily emission limits for the supply ship operating in dynamic positioning mode under Condition P.3 be revised as follows:

3. **Daily Emission Limits on Supply Ship in Dynamic Positioning Mode.** Emissions from all generator and propulsion engines in aggregate on the supply ship shall not exceed the emission limits specified for each of the pollutants below:

3.1. PM10: ~~75.09~~ 52.6 lbs/day

3.1.1. For compliance with Condition P.3.1, measurement of PM10 shall be determined using EPA Method s 201A and 202;

3.1.2 If an engine is certified to meet Marine CI engines or Nonroad CI Engines, no additional performance testing is required.

3.2. **$PM_{2.5}$:** ~~75.09~~ 52.6 lbs/day

3.2.1. For compliance with Condition P.3.2, measurement of $PM_{2.5}$ shall be determined using EPA Methods 201A and 202.

3.1.2 If an engine is certified to meet Marine CI engines or Nonroad CI Engines, no additional performance testing is required.

7.4 Compliance with Ambient Air Quality Standards and PSD Increments

This revision application includes several changes that affect emissions, so a dispersion modeling analysis addressing the net effect of all changes is included in Appendix D. That analysis confirms that the emission increases from the Discoverer and its associated fleet will not cause or contribute to violations of ambient air quality standards or PSD increments.

8 Eliminate Permit Conditions for Electrified Units

Since the Permit was issued, Shell elected to electrify the smallest cementing engine (FD-18) and the two logging winch engines (FD 19 and FD20). Shell previously reported this change to EPA because emissions testing would have otherwise been required. Because Shell has no plans to re-install diesel engines for these operating units, Shell requests that EPA clarify the permit by removing all references to FD-18, FD-19, and FD-20.

8.1 Proposed Permit Changes

Shell requests that units FD-18, FD-19 and FD-20 be removed from Table 1 of the Permit.

Shell requests that any references to units FD-16 -20 in the Table of Contents, Section I title and Permit conditions be replaced with FD-16-17. In addition, Shell requests that all references to Logging Engines be removed from the Permit sections listed above.

Shell proposes that the following Permit conditions be revised to remove reference to the electrified units, FD-18, FD-19 and FD-20.

I.1 Operation of Catalyzed Diesel Particulate Filter (CDPF). At all times that any of the cementing unit ~~and logging winch~~ engines (Units (FD-16 - 17) are in operation, the exhaust from each emission unit shall be directed to operating CleanAIR Systems CDPF, Part No. FDA300 for Units FD-16 and 17~~, Part No. FDA225 for Unit FD-18, and as specified by CleanAIR Systems for Units FD-19 - 20~~.

I. 2 BACT Limits. Emissions from each of Units (FD-16 - 17) shall not exceed the emission limits specified for each of the pollutants below:

2.2. PM:

FD-16 0.253 g/kW-hr

FD-17 0.253 g/kW-hr

~~FD-18 0.386 g/kW-hr~~

~~FD-19 0.03 g/kW-hr~~

~~FD-20 0.090 g/kW-hr~~

2.3. PM10:

FD-16 0.253 g/kW-hr

FD-17 0.253 g/kW-hr

~~FD-18 0.386 g/kW-hr~~

~~FD-19 0.03 g/kW-hr~~

~~FD-20 0.090 g/kW-hr~~

2.4. PM2.5:

FD-16 0.253 g/kW-hr

FD-17 0.253 g/kW-hr

~~FD-18 0.386 g/kW-hr~~

~~FD-19 0.03 g/kW-hr~~

~~FD-20 0.090 g/kW-hr~~

2.6. CO:

FD-16 0.40 g/kW-hr

FD-17 0.40 g/kW-hr

~~FD-18 0.880 g/kW-hr~~

~~FD-19 0.70 g/kW-hr~~

~~FD-20 0.550 g/kW-hr~~

2.7. VOC:

FD-16 0.20 g/kW-hr

FD-17 0.20 g/kW-hr

~~FD-18 0.270 g/kW-hr~~

~~FD-19 4.0 g/kW-hr~~

~~FD-20 0.750 g/kW-hr~~

Appendix A

Computer Simulations of the E-POD Configuration Within the Discoverer

Appendix B

E-POD Specifications

Appendix C

Discoverer Generator Emission Test Results

Appendix D

Ambient Air Quality Analysis

Appendix E

CleanAIR Manufacturer Guarantee

Appendix F

CleanAIR's Product Specification for HiBACK Units

Appendix G

Caterpillar 3608 Data Sheets

Appendix H

Nanuq Fuel Consumption/Engine Load Data

Appendix I

Crane Engine Temperature data

Appendix D. Air Quality Modeling Analysis

D-1. Introduction

EPA issued a Prevention of Significant Deterioration (PSD) Permit to Construct (the Permit) to Shell Gulf of Mexico Inc. (Shell) in September 2011.[1] ENVIRON conducted an air quality modeling analysis to confirm that proposed revisions to the Permit will not cause concentrations of criteria pollutants to exceed ambient air quality standards or Prevention of Significant Deterioration (PSD) increments. The PSD increment analysis performed here addresses Class II increments. There are different PSD increments for Class I areas (National parks, Wilderness Areas, etc.), but there are no Class I areas within proximity to the project area, and no Class I area impact analysis has been included in this air quality analysis.

Ambient air quality standards and PSD increments are unique for each airborne contaminant and also refer to specific averaging times. In some cases a specific air contaminant will have separate ambient standards or PSD increments for different averaging times. Table D-1 shows the ambient standards and PSD increments relevant to this air quality modeling analysis. To determine compliance with ambient air quality standards, the analysis adds predicted concentrations attributable to the project to background concentrations. Compliance with PSD increments is determined in this case solely on concentrations attributable to the project.

Table D-1: Summary of Applicable Standards

Pollutant	Averaging Time	NAAQS[1] ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)
Nitrogen Dioxide (NO_2)	1-hour	188[2]	Not Established
	Annual	100	25
Particulate Matter (PM_{10})	24-hour	150	30
	Annual[3]	50	17
Particulate Matter ($PM_{2.5}$)	24-hour	35	9
	Annual	15	4
Sulfur Dioxide (SO_2)	1-hour	196[3]	Not established
	3-hour	1,300	512
	24-hour	365	91
	Annual	80	20
Carbon Monoxide (CO)	1-hour	40,000	None
	8-hour	10,000	None

[1] National Ambient Air Quality Standards
[2] Based on 98th percentile of daily maximum hourly-averaged concentrations
[3] Based on 99th percentile of daily maximum hourly-averaged concentrations

[1] Outer Continental Shelf Prevention of Significant Deterioration Permit to Construct, Permit Number R10OCS/PSD-AK-09-01, Issuance Date September 19, 2011, Issuing Authority, United States Environmental protection Agency, Region 10.

The modeling analysis consists of the following steps:

- Model Selection
- Preparation of model inputs
- Exercising the model to compute ambient air concentration estimates
- Comparing model-predicted concentrations with ambient air quality standards.

Except as discussed below, this air quality modeling analysis uses the same techniques and data as the previous permit modeling analyses conducted in support of the application leading to the Permit. This appendix describes the current analysis in detail, but also relies, in part, on previous documentation. References to the phrases "previous analysis" or "previous modeling analysis" in this appendix refer to the cumulative documentation submitted by Shell as part of the air quality modeling demonstration for the 2011 permit.

D-2. Model Selection

The dispersion model used in the previous and current modeling analyses is EPA's AERMOD model.[2] AERMOD is the primary regulatory model used throughout the United States to evaluate the impact of stationary source emissions. It is recommended by EPA in formal guidance in 40 CFR Part 51, Appendix W, known as the Guideline on Air Quality Models.

The AERMOD modeling system also requires a series of support programs used to prepare information for use in the dispersion model. Key among these programs is the meteorological data pre-processor, known as AERMET. In the previous modeling analysis, AERMET was judged to be appropriate and was used for modeling during conditions when the surface of the Arctic Ocean was covered primarily in ice. This ice covering closely resembles land surface, for which the AERMET pre-processer was developed.

However, during conditions of open water, the AERMET pre-processor was judged inappropriate due to air/sea interface effects that change how air contaminants transport and disperse in the atmosphere over open water, a condition not well represented by the AERMET pre-processor. An alternative technique was adapted and used in the previous application based on the Coupled Ocean-Atmosphere Response Experiment (COARE) algorithm. Accordingly, the modeling system used in the previous application was referred to as the COARE-AERMOD system.

This current modeling analysis also uses AERMOD with the AERMET pre-processor for ice conditions and the COARE algorithm for preparing meteorological data during open-water conditions. The only model-selection difference between the current and previous modeling analyses is the version of the AERMOD model itself. The previous analysis used the older version of AERMOD, designated as version 09292, while the current analysis uses the more-recent 12060 version. The two versions appear to give identical concentration calculations. The only difference between these two model versions is that when using the model to compute

[2] http://www.epa.gov/ttn/scram/dispersion_prefrec.htm#aermod

concentrations of Nitrogen Dioxide (NO_2), the newer version requires one full year of meteorological data. Because the Shell exploration fleet will only be present in the Chukchi Sea for 120 days in any given drilling season, the previous modeling analysis only supplied meteorological data for the period being actually modeled. The additional hours of meteorological data must be provided to the current version of the model, but these meteorological data do not enter into the concentration calculations because the Shell emissions units have no emissions during these time periods. Accordingly, arbitrary or "dummy" data were provided to the model for the periods when Shell emissions units were not present. Other than this inconsequential difference, the meteorological data used in the current modeling analysis were identical to those used previously.

D-3. Preparation of Input Data

Model input data fall into three categories:

1. Emission unit information
2. Meteorological data
3. Receptor data

As discussed above, meteorological data are identical to those used in the previous modeling analysis. A complete discussion of these data is provided in Shell's March 18, 2011 submission to EPA.[3] The receptors used in the air quality modeling analysis are also identical to those used in the previous air quality modeling analysis. These are also discussed in the March 18, 2011 submission, and also in the EPA's Technical Support Document.[4]

The only difference in the current modeling analyses from the previous modeling analyses is in the emission unit information. Emission unit information can be further divided into two categories: emission unit configuration and emission rates.

D-3.1 Emission Unit Configuration

The emission unit configuration category includes the locations, heights, areas and other emission unit parameters. None of these configuration factors were changed from the previous modeling analysis. Some of the emission units are classified as POINT sources in the AERMOD terminology, and for those sources, the same locations, release heights, exhaust temperatures, exhaust velocities and stack diameters were used in the current modeling as were used in the previous modeling analysis. These are detailed in the Figure 3 and Table 5 of the Technical Support Document.[5]

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[3] Discoverer Drillship Impact Evaluation for SO_2 and NO_2 Using AERMOD, Chukchi and Beaufort Seas, Shell Alaska Exploratory Drilling Program, Prepared by Air Sciences, Inc., Golden, CO, Project 180-20-3, March 18, 2011.

[4] ftp://ftp.epa.gov/reg10ftp/alaska/ocs/chukchi/air/shell/discoverer/2011/discoverer_ambient_air_quality_impact_analysis_06242011.pdf pages 9-11

[5] Ibid pages 11-16

The remaining sources were classified in the AERMOD terminology as AREAPOLY sources, meaning they are area sources with an irregular shape defined by a series of vertices that represent a polygon. The emission source configuration for these sources was also identical to the previous air quality modeling analysis. Figure 1 shows the general arrangement of these AREAPOLY sources as used both in the previous modeling analysis and the current modeling

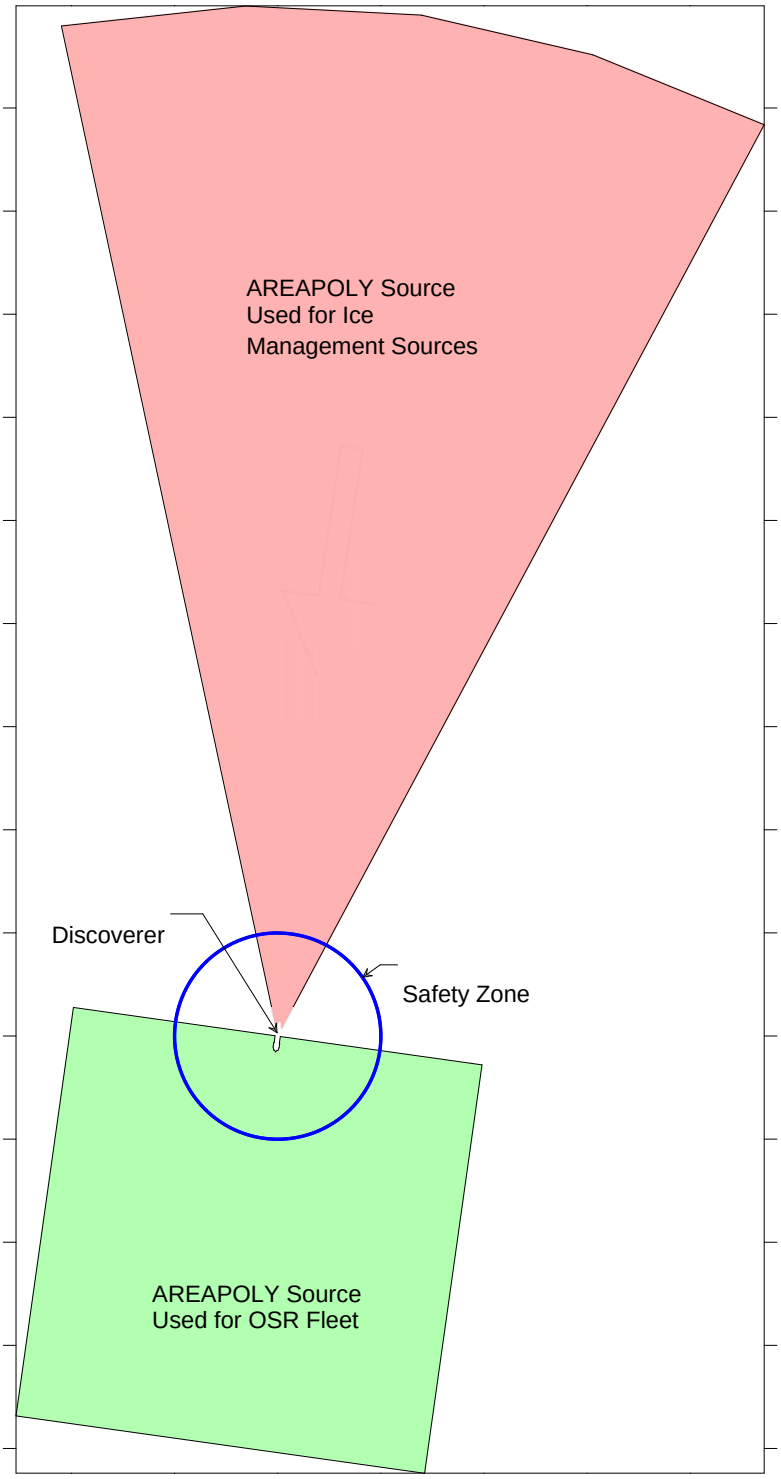

Figure D-1. AREAPOLY Source Configuration

analysis. It should be noted that the sources will rotate about the drill hole location with the wind direction so that for each hour, a different orientation will be observed aligning with the wind direction. Figure D-1 presents the configuration for a wind direction of 8 degrees east of north (direction from which the wind is coming).

Both the previous and current modeling analyses used emission sequences due to the fact that the emissions units for the exploration program do not run continuously, and in some cases are mutually exclusive. For example, one of the early exploration steps is developing a mud-line cellar. Some of the emissions units used in mud-line cellar development are unique to this task and not used in other phases of the drilling program. Conversely, a later phase of the exploration program involves a process called logging and cementing. Like mud-line cellar development, cementing and logging involves specialized emission units. These drilling program phases cannot occur simultaneously, and the specialized emission units used in these phases cannot operate simultaneously. And other emission units, such as the supply ship during the deliveries, the solid waste incinerator, the testing of the emergency generator and the main ice breaker that all operate intermittently.

To address this, emission sequences were developed reflecting the different drilling program phases. A schedule of emissions was developed for a full 120-day drilling season where each emissions unit was assigned operating hours based on expected activity. For some emissions units, such as the main generator engines, the heaters, the cranes, the anchor handler and the oil-spill recovery fleet, emissions were assumed to occur continuously for the entire 120-day drilling season, although this assumption is highly conservative because these emissions units operate intermittently. The conservative assumption was made because these emissions units have no definable pattern of operation.

For other emissions units, such as the mud-line cellar compressor engines, the high pressure units, the ice breaker, the incinerator, the emergency generator, and the supply ship, a pattern or sequence of emission was established. Table D-2 describes the emission sequence for each emissions unit.

Table D-2. Emission Sequences		
Emission Unit	**Hours Per Season**	**Description**
Main generators	2,880	Operate continuously
Emergency Generator	8	Operate for 2 hours, once per month
Mud-Line Cellar Compressors	480	Operate for 5 days to make one MLC for each drill hole and assume 4 drill holes per season
High Pressure Unit Engines	480	Operate for 5 days to make one MLC for each drill hole and assume 4 drill holes per season
Port Crane Engine	2,880	Operate continuously
Starboard Crane Engine	2,880	Operate continuously
Cementing/Logging Engines	1,248	Operate for 13 days to log/cement each drill hole and assume 4 drill holes per season
Heaters	2,880	Operate continuously
Seldom-Used Engines	2,880	Operate continuously
Incinerator	600	Operate 5 hours per day every day
Resupply Ship	624	Operate for 24 hours in DP mode and 2 hours in transit mode for each of 24 visits to the drill site
Ice Breaker	1,224	Operate during periods of ice only
Anchor Handler	2,880	Operate continuously
Oil-Spill Response Main Ships	2,880	Operate continuously
Oil-Spill Response Work Boats	2,880	Operate continuously

The same emission sequences used in the previous modeling analysis were used in the current analysis, with the following exception:

- The incinerator was further restricted from operating on days when the resupply ship was operating in dynamic positioning (DP) mode. With this restriction, the number of hours of operation for the incinerator was reduced from 600 to 480.

One other difference between the current and previous modeling analyses was the way in which the model runs were made. Previously, individual hours were modeled in separate runs of AERMOD. For each drill sequence, there were 2,880 separate runs of the AERMOD model. This approach was not possible in the current modeling analysis because the newer version of AERMOD requires a full year of meteorological data when modeling NOx. An alternative, but mathematically identical approach was used in the current modeling analysis. Runs for each sequence were made in a single full-year model run of AERMOD (with dummy meteorological data for the non-drill season hours, as noted above). The approach was to define 360 different model sources for each emission unit, one for each of the 360 degrees of wind direction. So instead of 16 model sources used previously, the current modeling analysis used 16 x 360 = 5,760 model sources.[6] A large hourly emission file was created that then inserted an emission rate of zero for 359 of the 360 sources for each hour and only inserted the actual emission rate for the emission source that reflected the wind direction in that hour.

[6] There are 15 sources listed in Table D-2, but the Resupply ship is modeled as a separate source when in DP mode versus transit mode.

For example, the main generators were represented by 360 different model sources with names MAIN0, MAIN1, MAIN2…MAIN359. In the first drill season hour of the 2009 meteorological data, the wind direction is 8, meaning that the wind during that hour is coming 8 degrees measured clockwise from north, or slightly east of north as shown in Figure D-1. For this hour, all of the MAIN emission sources are set to an emission rate of zero, except MAIN8 which has the actual emission rate for the generators during that hour. As a test, this model approach was run with the emission data from the previous modeling analysis and identical results were obtained.

Another consideration addressed in the previous modeling analysis was the start date of the drill season. The drill season is limited by the terms of the permit to 120 days, but those 120 days must occur within a 153-day window between July 1 and November 30. To take advantage of the full 120-day drilling season, Shell must commence the program between July 1 and August 3. Consequently, two start sequences were evaluated: one starting on July 1, called the "A sequence" and one starting on August 3, called the "B sequence." The current modeling used the same two sequences.

D-3.2 Emission Rates

This permit application requests revisions in the allowable emission rates of some emissions units. A summary of the requested emission rate changes follows:

For NOx:

- The application asks to raise the NOx emission factor for the main generators from 0.5 grams per kilowatt-hour (g/kW-hr) to 6.0 g/kW-hr. This affects both the hourly and annual emissions of NOx for the main generators. The Permit limits aggregate NOx emissions to 4.64 lb/hr, but this application requests the hourly NOx emission limit to be increased to 55.72 lb/hr. The Permit limits aggregate annual emissions to 5.83 tons per rolling 12-month average. This application requests that this limit be increased to 44.83 tons per rolling 12-month average (a 39-ton increase).
- The application asks to change the hourly NOx emissions from the deck cranes. The current limit is based on cranes operating at 40% load capacity and no more than 50% functioning time, for a net restriction on an hourly basis of only 20% of the potential emissions. The application seeks to remove the hourly restriction on crane use, which will change the current aggregate NOx emission limit from 2.48 lb/hr to 12.40 lb/hr.
- For the cementing and logging engines the Permit allows five separate engines to operate at an emission factor of 15.717 g/kW-hr. Three of these engines have now been converted to electric motors powered by the main generators, so there are only two remaining diesel-fueled cementing unit engines.

  The Permit limits aggregate daily fuel use to 320 gallons. Shell proposes keep this daily fuel limit. Although the Permit does not limit hourly fuel consumption directly, there is an effective hourly limit on fuel consumption to one twenty-fourth of the daily limit because hourly NOx emission are limited to 6.56 lb/hr, which is one twenty-fourth of the daily NOx emissions that would result from the daily fuel limit of 320 gallons. This application

proposes to revise the hourly emission limit from the present 6.56 lb/hr to 11.60 lb/hr. The effect of this request is that while Shell will continue to be limited to no more than 320 gallons per day of fuel for the cementing and logging engines, during any one hour they may burn as much as 28.2 gallons of fuel.

For PM

- For the deck crane engines, the Permit limits PM, PM_{10} and $PM_{2.5}$ to 0.0715 g/kW-hr. The application requests approval to operate these units without CDPFs and to revise the BACT limit to 0.4767 g/kW-hr, and requests that the daily allowable PM, PM_{10} and $PM_{2.5}$ emission rates be increased to 2.75 lb.
- As noted above, the Permit authorizes five cementing and logging engines and uses a single emission factor to calculate emissions from all engines. Three of these engines have been converted to electric power supplied by the main generators, so only two engines are emission units. The BACT limit for PM, PM_{10} and $PM_{2.5}$ in the Permit for the two remaining engines is 0.253 g/kW-hr, but the higher emission factor of 0.386 g/kW-hr (for an electrified engine) was the basis for the maximum daily PM emissions from the combined 5 engines. The application requests that the requirement to employ CDPFs be rescinded, that the BACT limit be revised to 1.69 g/kW-hr for PM, PM_{10}, and $PM_{2.5}$, and that the allowable daily PM, PM_{10}, and $PM_{2.5}$ emissions be revised to 16.88 lb/day.
- The Permit limits the resupply ship PM, PM_{10} and $PM_{2.5}$ emissions to 75.09 lb/day during periods when it is operating in dynamic positioning mode near the Discoverer. The application requests a revision in resupply ship PM, PM_{10} and $PM_{2.5}$ emissions to 52.55 lb/day.
- The Permit limits PM_{10} and $PM_{2.5}$ emissions from the Oil-Spill Response Main Ship (Nanuq) to 3.03 lb/day. The application requests a revised allowable PM, PM_{10}, and $PM_{2.5}$ limit of 10 lb/day.

For CO

- The application requests an increase in the emission factor for CO for the deck crane engines from the present permit limit of 0.220 g/kW-hr to 2.2 g/kW-hr. There is also an increase in the utilization requested for the 1-hour period, as described under NOx above. The net effect is an increase in the CO emission rate from the current level of 0.11 lb/hr to 2.64 lb/hr.
- The application requests an increase in the emission factor for CO from the cementing engines from the present permit limit of 0.4 g/kW-hr to 4.0 g/kW-hr. The net effect is an increase in the CO emission rate from the current level of 0.37 lb/hr to 3.53 lb/hr.

For SO_2

- The increased utilization of the deck cranes as described under NOx above results in an increase in SO2 emissions on a peak-hour basis from the current permit limit of 0.00326 lb/hr to 0.00814 lb/hr.

Table D-3 summarizes the emission changes requested as part of this application for NO_x and PM.

Table D-3. Summary of Requested Emission Changes in Permit Limits for NOx and PM

Emission Source	NOx						PM, PM_{10} and $PM_{2.5}$			
	Emission Factor (g/kW-hr)		Maximum Hourly Emissions (lb/hr)		Maximum Annual Emissions (t/y)		Emission Factor (g/kW-hr)		Maximum Daily Emissions (lb/day)	
	Current Permit	Proposed	Current Permit	Proposed	Current Permit	Proposed	Current Permit	Proposed	Current Permit	Proposed
Main Generators	0.5	6.0	4.64	55.72	5.83	44.83	0.127	0.127	28.3	28.3
Emergency Generator	none	none	19.73	19.73	-[1]	-[1]	none	none	2.77	2.77
MLC Compressor Engines	4.0	4.0	7.11	7.11	1.71	1.71	0.1	0.1	4.26	4.26
HPU Engines	4.0	4.0	3.29	3.29	0.79	0.79	0.03	0.03	0.59	0.59
Deck Cranes	10.327	10.327	2.48	12.40	2.76	2.76	0.0715	0.4767	0.41	2.75
Cementing and Logging Engines	13.155	13.155	6.56	11.60	4.09	4.09	0.253	1.69	3.87	16.88
Heat Boilers	0.20[2]	0.20[2]	3.19	3.19	4.59	4.59	0.235[2]	0.235[2]	8.99	8.99
Seldom-Used Engines	none	none	none	None	none	none	none	none	none	none
Incinerator	5.0[3]	5.0[3]	0.65	0.65	0.20	0.20	8.2[3] 7.0[4]	8.2[3] 7.0[4]	5.33[3] 4.55[4]	5.33[3] 4.55[4]
Resupply- DP	none	none	117.39	117.39	none	none	none	none	75.09	52.55
Resupply – Transit	none	none	none	None	none	none	none	none	none	none
Ice Breaker	none	none	67.96	67.96	41.59	41.59	none	none	277.47 269.66[5]	277.47 269.66[5]
Anchor Handler	none	none	69.06	69.06	99.45	99.45	none	none	281.46 273.82[5]	281.46 273.82[5]
OSR Main Ship Engines	none	none	67.44	67.44	97.11	97.11	none	none	3.03	10.0
OSR Main Other Srcs	none	none	none	None	none	none	none	none	none	none
OSR Work Boats	none	none	13.24	13.24	19.07	19.07	none	none	24.34	24.34

[1]annual and daily emissions for the emergency generator are effectively limited by operational limits of 10 hr/yr and 2 hr/day.

[2]emission factors for the heat boilers are in lb/MMBtu

[3]emission factors for the incinerator are in lb/ton of waste incinerated

[4]separate emission factors and emissions for PM_{10} (8.2 lb/ton and 5.33 lb/day) and $PM_{2.5}$ (7.0 lb/ton and 4.55 lb/day)

[5]Separate emission limits are provided for PM_{10} (top) and $PM_{2.5}$ (bottom)

Table D-4 shows the emission rates used in the current modeling analysis. These emission rates differ, in some cases, from those shown in Table D-3 for several reasons. First, while Table D-3 refers to explicit emission limits in the Permit, a number of emissions units are not subject to explicit numerical limits, but rather to operational limits, such as fuel limits, which effectively limit emissions. Second, the modeling also includes emissions from engines even if those emissions are not explicitly or operationally limited by the Permit. Finally, there are some cases where a higher emission rate was used in the air quality modeling than the Permit limit. The use of higher emission rates in the modeling ensures conservatism (over-prediction) in the modeling analysis and was generally done to account for short-term conditions, such as start-up (see discussion below). The purpose of using higher emission rates in the modeling is to provide added assurance that the ambient air quality standards and/or PSD increments will not be exceeded as a result of a short-term emission condition.

Table D-4. Modeled Emission Rates

Emissions Unit	NOx		$PM_{2.5}$	PM_{10}	CO	SO_2
	lb/hr	t/y	lb/day[1]	lb/day[1]	lb/hr	lb/hr[2]
Main Generators	63.11	44.83	28.31	28.31	1.66	0.06
Emergency Generator	19.73	0.08	2.77	2.77	4.25	0.01
MLC Compressor Engines	7.11	1.71	4.26	4.26	3.30	0.01
HPU Engines	3.29	0.79	0.59	0.59	0.58	0.01
Deck Cranes	12.40	2.76	2.75	2.75	2.64	0.01
Cementing and Logging Engines	11.60	4.09	16.88	16.88	3.53	0.01
Heat Boilers	3.19	4.59	8.99	8.99	1.23	0.03
Seldom-Used Engines	0.52	0.75	0.88	0.88	0.11	0.00
Incinerator	0.65	0.20	4.55	5.33	4.28	0.35
Resupply- DP	117.39	33.81	52.55	52.55	79.80[3]	0.13[3]
Resupply – Transit	8.80	0.21	0.47	0.47	79.80[3]	0.13[3]
Ice Breaker	191.29	41.59	269.75	277.51	30.15	0.29
Anchor Handler	196.21	99.45	273.76	281.52	30.84	0.29
OSR Main Ship	68.10	98.07	24.24	30.54	0.44	0.03
OSR Work Boats	13.24	19.07	24.34	24.34	2.15	0.003

[1]Daily emission rates were used for modeling all averaging times for $PM_{2.5}$ and PM_{10}.

[2]Hourly emission rates were used for modeling all averaging times for SO2.

[3]At any given time the resupply ship is either in transit or in DP, so only one of the two modes is included in the modeling

D-3.3 Start-Up Emissions

Except as noted in Table D-2, the modeling analysis assumes engines are operating all the time. In practice, engines are turned off when they are not needed, which eliminates emissions from those engines. As a result, the modeling assumptions can generally be assumed to be conservative (over-predicting) because they assume that engines are operating when in fact

there are times when they are not. This is especially true for longer time periods such as a full day or the entire drilling season.

As discussed in Chapter 6 of the application, an engine starting up emits at a higher rate if there is an emission control device attached because most of the control devices do not function well until warmed to operating temperature. While over a 24-hour period or the entire drilling season, these short-term emission increases would be more than compensated for by the downtime of the engine shut-down, for an hour it is likely that emissions could be higher. These higher emissions during start-up are a normal, unavoidable occurrence with every engine equipped with emission controls.

In order to ensure that start-up emissions do not cause concentrations that exceed short-term standards, the current modeling assumes that NOx emissions from SCR-controlled engines would be higher for an hour for each startup. These include the Discoverer's main generators and certain larger engines on the two ice management vessels. The following assumptions were made to calculate start-up emissions:

- Emissions for an engine during start-up are equivalent to uncontrolled engine emissions at full load.
- Start-up emissions last for 1-hour
- For the main generators, it was assumed that two of the six engines could be in start-up mode at any time. It is recognized that this greatly over-states the number of start-up events.
- For the ice breaker and the anchor handler, one quarter of the total engine horsepower on each vessel was assumed to start-up 6 times per day. Essentially, every fourth hour was assumed to be a "start-up hour" in which one quarter of the engine capacity was assumed to be uncontrolled.

D-4. Model Results

D-4.1 Criteria Pollutant Analysis

AERMOD was used to establish pollutant concentrations at each of the 2,082 receptors for each hour of the meteorological data set. These hourly results were then sorted and averaged to determine the compliance with the ambient criteria shown in Table D-1. For compliance with the NAAQS, a background concentration, which includes the effects of natural background and man-made sources of emission not included in the air quality modeling, must be added to the model results. The background values used here are the same as was used in the previous air quality modeling analysis.[7] Comparison with PSD increments does not require the addition of a background concentration. Table D-5 summarizes the model results.

[7] ftp://ftp.epa.gov/reg10ftp/alaska/ocs/chukchi/air/shell/discoverer/2011/discoverer_ambient_air_quality_impact_analysis_06242011.pdf page 31

Table D-5. Summary of Model Results

Air Pollutant	Averaging Period	Shell Only Impacts (without background) (µg/m^3)	PSD Increment (µg/m^3)	Exceeds PSD Increment?	Background Concentration (µg/m^3)	Total Impact Including Background (µg/m^3)	NNAQS or AAQS (µg/m^3)	Exceeds NAAQS?
NO_2	1-hour	163.4	None	No	13.2	176.6	188	No
	Annual	9.4	25	No	2.0	11.4	100	No
$PM_{2.5}$	24-hour	8.9[1]	9	No	11.0	20.6[1]	35	No
	Annual	1.7	4	No	2.0	3.7	15	No
PM_{10}	24-hour	9.2	30	No	79.0	91.0	150	No
SO_2	1-hour	16.1	None	No	23.0	39.1	196	No
	3-hour	10.9	512	No	14.0	24.9	1300	No
	24-hour	1.9	91	No	5.0	6.9	365	No
	Annual	0.1	20	No	0.4	0.5	80	No
CO	1-hour	1,079	None	No	959.0	2,038	40000	No
	8-hour	592	None	No	945.0	1,537	10000	No

[1]The metric used for $PM_{2.5}$ is different for the PSD increment and the NAAQS. For the PSD increment, the highest second high at each receptor is determined for each of the 4 model sequences for $PM_{2.5}$ (2009A, 2009B, 2010A, 2010B) and the highest of these four values is shown in the table at 8.9 µg/m^3. For the NAAQS, the highest value at each receptor for the two 2009 sequences is averaged with the highest value for the two 2010 sequences. The highest of these values across all receptors was 9.6 µg/m^3, which when added to the background concentration of 11.0 is 20.6 µg/m^3 as shown in the table.

The modeling results summarized in Table D-5 demonstrate that emissions attributable to the Discoverer and its associated fleet, as revised in this permit application, continue to comply with ambient air quality standards and PSD increments.

D-4.2 Secondary Aerosols

Secondary aerosols are small particles that form in the air as a result of the interaction of certain gases. In particular, nitrogen dioxide and sulfur dioxide can combine with ammonia to form ammonium nitrate and ammonium sulfate, common secondary aerosols. Because the Shell exploration program produces emissions of these gases, EPA has previously asked Shell to evaluate the potential impact of any secondary aerosols in the villages that border the Chukchi Sea. Note that it takes time for the secondary aerosol chemistry to occur, and modeling analyses virtually always show higher PM concentrations near a source due to directly emitted particulate matter. However, over long distances, secondary aerosol formation can have a more significant contribution to total PM concentrations.

To evaluate secondary aerosols, receptors were placed at both Point Lay and Wainwright, as well as at over-water locations at a distance of 50 kilometers on a direct line with each village. Intermediate receptors were included because AERMOD is only recommended for calculating concentrations up to 50 kilometers, and both villages are farther than 50 kilometers from the drilling locations in the Chukchi Sea.

Table D-6 shows the concentrations of NO_2 and SO_2 calculated at these locations. In the Table, 24-hour average concentrations are used although there are no formal criteria for nitrate or sulfate. For purposes of this conservative analysis, we have assumed 100% of the NO_2 would convert to nitrate and 100% of the SO_2 would convert to sulfate. It is unlikely that this rate of conversion would be obtained, so the concentrations in Table D-6 should be considered an over-estimate of possible nitrate or sulfate concentrations.

Table D-6. Chukchi Sea Village Concentrations in µg/m^3

Location	NO2 Concentration	SO2 Concentration	Nitrate Concentration If 100% Converts	Sulfate Concentration If 100% Converts
Point Lay Village	2.3	<0.1	4.0	<0.1
Wainwright Village	2.8	<0.1	4.9	<0.1
Receptor in the Direction of Point Lay at a Distance of 50 km from the Discoverer	4.6	<0.1	8.0	<0.1
Receptor in the Direction of Wainwright at a Distance of 50 km from the Discoverer	5.0	<0.1	8.7	<0.1

There are no ambient criteria specific to sulfate or nitrate, but these particulate concentrations are well below the 35 µg/m³ ambient air quality standard for PM2.5.