Statement of Basis

Permit to Construct No. P-2016.0011
Project ID 61684

St. Luke's Nampa Medical Center
Nampa, Idaho

Facility ID 027-00152

Proposed for Public Comment

September 29, 2016
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Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

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FACILITY INFORMATION

Description

St. Luke's Nampa Medical Center operates an existing office building in Nampa, Idaho. The facility is expanding into a medical care center and supporting central plant. The central plant will consist of three dual-fuel boilers which provide steam for the hospital, two cooling towers, and four diesel-fired IC engines for emergency backup electric power. The facility also has diesel fuel storage tanks for backup fuel for the boilers and the IC engines.

This permitting action involves installing of the three boilers, two cooling towers, four emergency IC engines, and associated diesel fuel storage tanks.

Permitting History

This is the initial PTC for a new facility thus there is no permitting history.

Application Scope

This PTC is for a minor modification at an existing minor facility. The applicant has proposed to install and operate three boilers which provide steam for the hospital, two cooling towers, and four diesel IC engines for emergency backup electric power.

Application Chronology

May 13, 2016	DEQ received an application and an application fee.
July 11 – July 26, 2016	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
April 20, 2016	DEQ determined that the application was incomplete.
June 10, 2016	DEQ determined that the application was complete.
July 28, 2016	DEQ made available the draft permit and statement of basis for peer and regional office review.
August 5, 2016	DEQ made available the draft permit and statement of basis for applicant review.
August 17, 2016	DEQ received the permit processing fee.
August 23 – September 22, 2016	DEQ provided a public comment period
September 29, 2016	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source	Control Equipment	Emission Points
Emergency Generators GEN1-GEN4 IC Engines * Caterpillar Model C27 *Rated at 800kW (1,214 hp) *Allowable fuel type: diesel fuel *Manufactured:2016	None	Emergency Generators GEN1-GEN4 exhaust Stacks
Boilers #1-#3 *Hurst Model 350 hp – Series 500 *14.25 MMBtu/hr *Allowable fuel type(s): natural gas with diesel backup *Manufactured: 2016	None	Boilers 1-3 Exhaust Stacks
Cooling Towers 1-2 *Baltimore Aircoil Co, inc. *Model XES3E-1424-07M *Manufactured: 2016 *Flowrate 1500 gpm	None	Cooling Tower Exhausts 1A, 1B, 2A, and 2B

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit an emission inventory was developed for the three boilers, two cooling towers, and four emergency IC operations at the facility (see Appendix A) associated with this proposed project. Emissions estimates of criteria pollutant and HAP PTE were based on emission factors from AP-42, AP-41, manufacturer performance data, and 8760 hours per year for the cooling towers, 100 hours per year for the emergency engines, and 8712 hours of normal natural gas duel-fired boiler operation with 48 hours of testing of the diesel back-up.

Uncontrolled Potential to Emit

Using the definition of Potential to Emit, uncontrolled Potential to Emit is then defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall **not** be treated as part of its design **since** the limitation or the effect it would have on emissions **is not** state or federally enforceable.

The uncontrolled Potential to Emit is used to determine if a facility is a "Synthetic Minor" source of emissions. Synthetic Minor sources are facilities that have an uncontrolled Potential to Emit for regulated air pollutants or HAP above the applicable Major Source threshold without permit limits.

The following table presents the uncontrolled Potential to Emit for regulated air pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For the three boilers, two cooling towers, and four emergency IC engines at the facility, uncontrolled Potential to Emit is assumed to be the same as the Potential to Emit as all emissions calculations were performed at the worst-case maximum for this medical center uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8760 hr/yr, except for the emergency generators evaluated at 100 hours per year.

Table 2 UNCONTROLLED POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
	T/yr	T/yr	T/yr	T/yr	T/yr
GEN1	0.01	0.001	0.83	4.99	0.01
GEN2	0.01	0.001	0.83	4.99	0.01
GEN3	0.01	0.001	0.83	4.99	0.01
GEN4	0.01	0.001	0.83	4.99	0.01
Boiler #1	0.46	0.1	2.09	2.31	1.56
Boiler #2	0.46	0.1	2.09	2.31	1.56
Boiler #3	0.46	0.1	2.09	2.31	1.56
Cooling Tower 1	0.021	--	--	--	--
Cooling Tower 2	0.021	--	--	--	--
Total	**1.46**	**0.30**	**26.51**	**26.89**	**4.72**

The following table presents the uncontrolled Potential to Emit for HAP pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For this medical center uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8760 hr/yr, except for the emergency generators evaluated at 100 hours per year. Then, the worst-case maximum HAP Potential to Emit was determined for this medical center expansion.

Table 3 UNCONTROLLED POTENTIAL TO EMIT FOR HAZARDOUS AIR POLLUTANTS

Hazardous Air Pollutants	PTE (T/yr)
Acetaldehyde	4.04E-05
Acrolein	1.26E-05
Benzene	1.63E-03
Ethylbenzene	4.81E-07
Formaldehyde	1.39E-02
Hexane	3.30E-01
Naphthalene	3.21E-04
Toluene	1.08E-03
o-Xylene	3.10E-04
POM	1.54E-05
Arsenic	1.22E-05
Beryllium	8.44E-07
Cadmium	6.73E-05
Chromium	8.57E-05
Cobalt	5.14E-06
Manganese	2.33E-05
Mercury	1.59E-05
Nickel	1.29E-04
Selenium	4.22E-06
Total	**0.35**

Pre-Project Potential to Emit

Pre-project Potential to Emit is used to establish the change in emissions at a facility as a result of this project.

This is an existing facility. However, since this is the first time the facility is receiving a permit, pre-project emissions are set to zero for all criteria pollutants.

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all permit limits resulting from this project.

The following table presents the post project Potential to Emit for criteria pollutants from all emissions units at the facility as determined by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 4 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
GEN1	0.12	0.01	0.012	0.001	16.63	0.83	1.140	0.057	0.150	0.008
GEN2	0.12	0.01	0.012	0.001	16.63	0.83	1.140	0.057	0.150	0.008
GEN3	0.12	0.01	0.012	0.001	16.63	0.83	1.140	0.057	0.150	0.008
GEN4	0.12	0.01	0.012	0.001	16.63	0.83	1.140	0.057	0.150	0.008
Boiler #1	0.105	0.3	0.022	0.098	1.764	2.09	0.527	2.310	0.356	1.553
Boiler #2	0.105	0.3	0.022	0.098	1.764	2.09	0.527	2.310	0.356	1.553
Boiler #3	0.105	0.3	0.022	0.098	1.764	2.09	0.527	2.310	0.356	1.553

Cooling Tower 1	0.0024	0.021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower 2	0.0024	0.021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Post Project Totals	**0.80**	**0.98**	**0.11**	**0.30**	**71.81**	**9.59**	**6.14**	**7.16**	**1.67**	**4.69**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 5 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Post Project Potential to Emit	**0.80**	**0.98**	**0.11**	**0.30**	**71.81**	**9.59**	**6.14**	**7.16**	**1.67**	**4.69**
Changes in Potential to Emit	**0.80**	**0.98**	**0.11**	**0.30**	**71.81**	**9.59**	**6.14**	**7.16**	**1.67**	**4.69**

A summary of the estimated PTE for emissions increase of toxic air pollutants (TAP) is provided in the following table.

Post-project, *i.e.* change in, carcinogenic and non-carcinogenic TAP emissions are presented in the following table:

Table 6 POST PROJECT POTENTIAL TO EMIT FOR TOXIC AIR POLLUTANTS

Non-Carcinogenic Toxic Air Pollutants	Post Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Non-Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
3-Methylchloranthrene	7.55E-08	2.50E-06	N
Benzene	8.80E-05	8.00E-04	N
Benzo(a)pyrene	5.03E-08	2.00E-06	N
Dichlorobenzene	5.03E-05	2.00E+01	N
Formaldehyde	3.14E-03	5.10E-04	Y
Hexane	7.55E-02	1.20E+01	N
Naphthalene	2.56E-05	3.33	N
Toluene	1.43E-04	25	N
o-Xylene	1.88E-07	29	N
Arsenic	2.79E-06	1.50E-06	Y
Barium	6.15E-05	0.033	N
Beryllium	1.93E-07	2.80E-05	N
Cadmium	1.54E-05	3.70E-06	Y
Chromium	1.96E-05	0.033	N
Cobalt	1.17E-06	0.0033	N
Copper	1.19E-05	0.013	N
Manganese	5.31E-06	0.067	N
Molybdenum	1.54E-05	0.333	N
Nickel	2.93E-05	2.70E-05	Y
Selenium	9.63E-07	0.013	N
Vanadium	4.61E-05	3.00E-03	N
Zinc	4.05E-04	0.667	N

See regulatory review of IDAPA 58.01.01.210 below for a complete discussion of the compounds and elements exceeding TAPs EL screening level.

Ambient Air Quality Impact Analyses

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix C).

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP). A summary of the Ambient Air Impact Analysis for TAP is provided in Appendix C.

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Canyon County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For THAPs (Total Hazardous Air Pollutants) Only:

A = Use when any one HAP has actual or potential emissions ≥ 10 T/yr or if the aggregate of all HAPS (Total HAPs) has actual or potential emissions ≥ 25 T/yr.

SM80 = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits ≥ 8 T/yr of a single HAP or ≥ 20 T/yr of THAP.

SM = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.

B = Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold

UNK = Class is unknown

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are < 80 T/yr.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

UNK = Class is unknown.

Table7 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	3.53	0.3	**100**	B
$PM_{10}/PM_{2.5}$	3.53	0.3	**100**	B
SO_2	0.51	0.01	**100**	B
NO_X	26.51	9.6	**100**	B
CO	26.9	<100	**100**	B
VOC	7.3	<100	**100**	B
HAP (single)	<0.6	<10	**10**	B
HAP (Total)	<0.6	<25	**25**	B

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the proposed new emissions sources. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625 Visible Emissions

The sources of PM emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity. This requirement is assured by Permit Conditions 2.4 and 3.4.

Compliance with Toxic Standards (IDAPA 58.01.01.210)

IDAPA 58.01.01.210 Demonstration of Pre-construction Compliance with Toxic Standards

Although some of TAPs were above the screening levels that trigger modeling from IDAPA 58.01.01.586 for toxic substances, the compounds and elements above the EL screening levels are that TAPs that are HAPs which are regulated by an NSPS or NESHAP do not need to be modeled; therefore, no further review is required under IDAPA 58.01.01.210 for these pollutants for sources subject to 40 CFR Part 63, The Toxic Air Pollutants that are not one of the 187 Hazardous Air Pollutants are determined to be in compliance with IDAPA 210 in accordance with IDAPA 58.01.01.203.03.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301 Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility do not have a potential to emit greater than 100 tons per year for PM_{10}, $PM_{2.5}$, SO_2 , NO_X , CO, and VOC or 10 tons per year for any one HAP or 25 tons per year for all HAP combined as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, the facility is not a Tier I source in accordance with IDAPA 58.01.01.006 and the requirements of IDAPA 58.01.01.301 do not apply.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility-wide emissions of any criteria pollutant that exceed 250 T/yr.

NSPS Applicability (40 CFR 60)

The facility operates three boilers and four emergency IC engines for which the following NSPS requirements apply:

- **40 CFR 60, Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**

- **40 CFR 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**

See Appendix B for complete breakdown of these subparts as presented by the applicant.

NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT Applicability (40 CFR 63)

The facility operates four emergency IC engines for which the following NESHAP requirements apply:

- **40 CFR 63, Subpart ZZZZ……..National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines**

  The three boilers use diesel as back up fuel for which the following NSPS requirements could apply, but doesn't:

- **40 CFR 63 Subpart JJJJJJ-National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources**

See Appendix B for complete breakdown of the subpart as presented by the applicant.

Permit Conditions Review

This section describes the permit conditions for this initial permit.

Initial Permit Condition 1.1
This is the initial PTC for this facility. The expansion of the existing office building into a medical center will include the addition of more floor space and a supporting central plant. Table 1.1 presents the components of the central plant as described by the applicant. The cooling towers were omitted, as the emissions are minor and components consist of few or no inspection requirements.

Emergency Generators

Initial Permit Condition 2.1
The central plant contains four diesel-fired IC engines which are used to power electrical generators during emergency situations.

Initial Permit Condition 2.2
The four emergency generators operate with no control devices on the exhaust stacks. Table 2.2 presents the generators GEN1-GEN 4 emission points as presented in the application.

Initial Permit Condition 2.3
This permit condition lists the criteria pollutant emissions for the emissions units permitted in this section of the permit. CO and VOC levels in this application were well below regulatory concern and the estimates were developed from manufacturer performance data, which is considered to be reliable. Therefore, there were no limits for CO and VOC included.

Permit Condition 2.4
Permit Condition 2.4 establishes that emissions shall not exceed 20% opacity as required by IDAPA 625.

Initial Permit Condition 2.5
This permit condition requires recordkeeping of the sulfur content in the fuel used in the emergency generators.

40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Initial Permit Condition 2.6
In accordance with 40 CFR 60.4202(a)(2) the emergency IC engines shall be operated to limit opacity exhaust and in accordance with manufacturer certification.

Initial Permit Condition 2.7
In accordance with 40 CFR 60.4207(a) the emergency IC engines shall operate on fuel with a maximum sulfur content of 15 ppm.

Initial Permit Condition 2.8
In accordance with 40 CFR 60.4209(a) the emergency IC engines shall have a non-resettable hour meter installed, shall not change setting from manufacturers specifications, and limit testing to 100 hours per year.

Initial Permit Condition 2.9
In accordance with 40 CFR 60.4214(b) the permittee must record the time of operation of the engine and the reason the engine was in operation during that time.

Boilers

Initial Permit Condition 3.1
Initial Permit Condition 3.1 describes the three boilers in the central plant.

Initial Permit Condition 3.2
The three boilers operate with no control devices on the exhaust stacks. Table 3.2 presents the Boilers #1 through #3 emission points as presented in the application.

Initial Permit Condition 3.3
This permit condition lists the criteria pollutant emissions for the emissions units permitted in this section of the permit. CO and VOC levels in this application were well below regulatory concern and the estimates were developed from manufacturer performance data, which is considered to be reliable. Therefore, there were no limits for CO and VOC included.

Initial Permit Condition 3.4
In accordance with IDAPA 58.01.01.676 fuel burning equipment PM limits for back-up operation of the boilers.

Initial Permit Condition 3.5
This permit condition specifies the NG for primary operation and diesel fuel for back-up operation.

Initial Permit Condition 3.6
Permit Condition 3.7 limits testing of the boilers with backup fuel to 48 hours per boiler per consecutive 12 month period and only one unit can be tested at a time as modeling compliance was demonstrated under these conditions.

Initial Permit Condition 3.7
The diesel fuel shall have a maximum sulfur content of 0.05% by weight.

Initial Permit Condition 3.8
This permit condition specifies requirements for recordkeeping for back-up fuel operation of the boilers.

Initial Permit Condition 3.9
This permit condition specifies requirements for recordkeeping of the sulfur content of the fuel used for back-up operation of the boilers.

40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Initial Permit Condition 3.10
In accordance with 40 CFR 60.44c the permittee shall conduct an initial performance test according to paragraph (b) as proposed by the applicant, or opt to use fuel samples or supplier certifications as stated in paragraph (a) through exceptions in paragraphs (g) and (h).

Initial Permit Condition 3.11
In accordance with 40 CFR 60.46c the permittee must demonstrate sulfur dioxide compliance by monitoring the percent sulfur content by weight using fuel samples or supplier certifications.

Initial Permit Condition 3.12

In accordance with 40 CFR 60.48c the permittee is required to record boiler construction and startup dates, amounts of fuel combusted each day and keep records maintained and available upon request for at least two years. A semiannual report to DEQ of sulfur dioxide is also required.

Initial Permit Condition 3.13
In any case where any permit condition conflicts with NSPS or NESHAP requirements. The federal requirement will take precedent.

General Provisions

Initial Permit Condition 5.1
The duty to comply general compliance provision requires that the permittee comply with all of the permit terms and conditions pursuant to Idaho Code §39-101.

Initial Permit Condition 5.2
The maintenance and operation general compliance provision requires that the permittee maintain and operate all treatment and control facilities at the facility in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 5.3
The obligation to comply general compliance provision specifies that no permit condition is intended to relieve or exempt the permittee from compliance with applicable state and federal requirements, in accordance with IDAPA 58.01.01.212.01.

Initial Permit Condition 5.4
The inspection and entry provision requires that the permittee allow DEQ inspection and entry pursuant to Idaho Code §39-108.

Initial Permit Condition 5.5
The permit expiration construction and operation provision specifies that the permit expires if construction has not begun within two years of permit issuance or if construction has been suspended for a year in accordance with IDAPA 58.01.01.211.02.

Initial Permit Condition 5.6
The notification of construction and operation provision requires that the permittee notify DEQ of the dates of construction and operation, in accordance with IDAPA 58.01.01.211.03.

Initial Permit Condition 5.7
The performance testing notification of intent provision requires that the permittee notify DEQ at least 15 days prior to any performance test to provide DEQ the option to have an observer present, in accordance with IDAPA 58.01.01.157.03.

Initial Permit Condition 5.8
The performance test protocol provision requires that any performance testing be conducted in accordance with the procedures of IDAPA 58.01.01.157, and encourages the permittee to submit a protocol to DEQ for approval prior to testing.

Initial Permit Condition 5.9
The performance test report provision requires that the permittee report any performance test results to DEQ within 30 days of completion, in accordance with IDAPA 58.01.01.157.04-05.

Initial Permit Condition 5.10
The monitoring and recordkeeping provision requires that the permittee maintain sufficient records to ensure compliance with permit conditions, in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 5.11
The excess emissions provision requires that the permittee follow the procedures required for excess emissions events, in accordance with IDAPA 58.01.01.130-136.

Initial Permit Condition 5.12
The certification provision requires that a responsible official certify all documents submitted to DEQ, in accordance with IDAPA 58.01.01.123.

Initial Permit Condition 5.13
The false statement provision requires that no person make false statements, representations, or certifications, in accordance with IDAPA 58.01.01.125.

Initial Permit Condition 5.14
The tampering provision requires that no person render inaccurate any required monitoring device or method, in accordance with IDAPA 58.01.01.126.

Initial Permit Condition 5.15
The transferability provision specifies that this permit to construct is transferable, in accordance with the procedures of IDAPA 58.01.01.209.06.

Initial Permit Condition 5.16
The severability provision specifies that permit conditions are severable, in accordance with IDAPA 58.01.01.211.

PUBLIC REVIEW

Public Comment Opportunity

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c or IDAPA 58.01.01.404.01.c. During this time there was a request for a public comment period on DEQ's proposed action. Refer to the chronology for public comment opportunity dates.

Public Comment Period

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.01.c. During this time, comments were submitted in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

A response to public comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

APPENDIX A – EMISSIONS INVENTORIES

St Lukes Nampa Medical Center
Criteria Pollutant Summary

Criteria Pollutants	PM10 [a]		PM2.5 [a]		CO [a]		NOx		SOx [a]		Lead [a]		VOC	
Emissions Unit Name	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)
Gen 1 [b]	0.12	0.01	0.12	0.01	1.14	0.06	16.63	0.83	0.012	0.001			0.15	0.01
Gen 2 [b]	0.12	0.01	0.12	0.01	1.14	0.06	16.63	0.83	0.012	0.001			0.15	0.01
Gen 3 [b]	0.12	0.01	0.12	0.01	1.14	0.06	16.63	0.83	0.012	0.001			0.15	0.01
Gen 4 [b]	0.12	0.01	0.12	0.01	1.14	0.06	16.63	0.83	0.012	0.001			0.15	0.01
Boiler #1 (NG)		0.30	0.068	0.2986	0.53	2.31		2.09	0.022	0.098	6.99E-06	3.04E-05	0.356	1.55
Boiler #1 (ULSD)	**0.105**						**1.76**							
Boiler #2 (NG)		0.30	0.068	0.30	0.53	2.31		2.09	0.022	0.098	6.99E-06	3.04E-05	0.356	1.55
Boiler #2 (ULSD)	**0.105**						**1.76**							
Boiler #3 (NG)		0.30	0.068	0.30	0.53	2.31		2.09	0.022	0.098	6.99E-06	3.04E-05	0.356	1.55
Boiler #3 (ULSD)	**0.105**						**1.76**							
Cooling Tower 1A	0.002364	0.01036	0.002364	0.01036										
Cooling Tower 1B	0.002364	0.01036	0.002364	0.01036										
Cooling Tower 2A	0.002364	0.01036	0.002364	0.01036										
Cooling Tower 2B	0.002364	0.01036	0.002364	0.01036										
Totals	**0.80**	**0.97**	**0.69**	**0.96**	**6.14**	**7.16**	**71.81**	**9.60**	**0.12**	**0.30**	**2.10E-05**	**9.13E-05**	**1.67**	**4.69**

Note:
a Facility emissions are BRC exempt
b Short term NO_2 modeling not required for intermittent sources
For Boilers #1 through #3 used worse-case emission factors between NG and ULSD.
Requires Modeling

Monthly Pb Emissions
5.20E-03 5.07E-03 NO

St Lukes Nampa Medical Center

Toxic and Hazardous Air Pollutants Summary

Current Baseline

TAPs/HAPs	HAPs	Boilers 1-3		Gens 1-4		Facility Wide Total		
		(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)[1]	(ton/yr)	
2-Methylnaphthalene	No	1.01E-06	4.41E-06			1.01E-06	4.41E-06	
3-Methylchloranthrene	No	7.55E-08	3.30E-07			7.55E-08	3.30E-07	
7,12-Dimethylbenz(a)anthracene	No	6.71E-07	2.94E-06			6.71E-07	2.94E-06	
Acenaphthene	No	7.55E-08	3.30E-07	1.71E-06	7.51E-06	7.55E-08	7.84E-06	
Acenaphthylene	No	7.55E-08	3.30E-07	3.38E-06	1.48E-05	7.55E-08	1.51E-05	
Acetaldehyde	Yes			9.23E-06	4.04E-05	0.00E+00	4.04E-05	
Acrolein	Yes			2.89E-06	1.26E-05	0.00E+00	1.26E-05	
Anthracene	No	1.01E-07	4.41E-07	4.51E-07	1.97E-06	1.01E-07	2.41E-06	
Benzo(a)anthracene	No	7.55E-08	3.30E-07	2.28E-07	9.98E-07	7.55E-08	1.33E-06	
Benzene	Yes	8.80E-05	3.86E-04	2.84E-04	1.25E-03	8.80E-05	1.63E-03	Annual Ave
Benzo(a)pyrene	No	5.03E-08	2.20E-07	9.41E-08	4.12E-07	5.03E-08	6.33E-07	
Benzo(b)fluoranthene	No	7.55E-08	3.30E-07	4.07E-07	1.78E-06	7.55E-08	2.11E-06	
Benzo(g,h,i)perylene	No	5.03E-08	2.20E-07	2.04E-07	8.92E-07	5.03E-08	1.11E-06	
Benzo(k)fluoranthene	No	7.55E-08	3.30E-07	7.99E-08	3.50E-07	7.55E-08	6.80E-07	
Chrysene	No	7.55E-08	3.30E-07	5.60E-07	2.45E-06	7.55E-08	2.79E-06	
Dibenz(a,h)anthracene	No	5.03E-08	2.20E-07	1.27E-07	5.55E-07	5.03E-08	7.75E-07	
Dichlorobenzene	No	5.03E-05	2.20E-04			5.03E-05	2.20E-04	
Ethylbenzene	Yes	1.10E-07	4.81E-07			1.10E-07	4.81E-07	
Fluoranthene	No	1.26E-07	5.51E-07	1.48E-06	6.47E-06	1.26E-07	7.02E-06	
Fluorene	No	1.17E-07	5.14E-07	4.69E-06	2.05E-05	1.17E-07	2.11E-05	
Formaldehyde	Yes	3.14E-03	1.38E-02	2.89E-05	1.27E-04	3.14E-03	1.39E-02	Annual Ave
Hexane	Yes	7.55E-02	3.30E-01			7.55E-02	3.30E-01	
Indeno(1,2,3-cd)pyrene	No	7.55E-08	3.30E-07	1.52E-07	6.64E-07	7.55E-08	9.95E-07	
Naphthalene	Yes	2.56E-05	1.12E-04	4.76E-05	2.09E-04	2.56E-05	3.21E-04	Annual Ave
Phenanthrene	No	7.13E-07	3.12E-06	1.49E-05	6.55E-05	7.13E-07	6.86E-05	
Propylene	No			1.02E-03	4.48E-03	0.00E+00	4.48E-03	
Pyrene	No	2.10E-07	9.18E-07	1.36E-06	5.95E-06	2.10E-07	6.87E-06	
Toluene	Yes	1.43E-04	6.24E-04	1.03E-04	4.51E-04	1.43E-04	1.08E-03	
o-Xylene	Yes	1.88E-07	8.24E-07	7.07E-05	3.10E-04	1.88E-07	3.10E-04	
PAH	No			7.77E-05	7.21E-06	0.00E+00	7.21E-06	Annual Ave
POM	Yes	4.78E-07	1.98E-06	1.65E-06	1.34E-05	4.78E-07	1.54E-05	Annual Ave
TAPs/HAPs Metals								
Arsenic	Yes	2.79E-06	1.22E-05			2.79E-06	1.22E-05	Annual Ave
Barium	No	6.15E-05	2.69E-04			6.15E-05	2.69E-04	
Beryllium	Yes	1.93E-07	8.44E-07			1.93E-07	8.44E-07	
Cadmium	Yes	1.54E-05	6.73E-05			1.54E-05	6.73E-05	Annual Ave
Chromium	Yes	1.96E-05	8.57E-05			1.96E-05	8.57E-05	
Cobalt	Yes	1.17E-06	5.14E-06			1.17E-06	5.14E-06	
Copper	No	1.19E-05	5.20E-05			1.19E-05	5.20E-05	
Manganese	Yes	5.31E-06	2.33E-05			5.31E-06	2.33E-05	
Mercury	Yes	3.63E-06	1.59E-05			3.63E-06	1.59E-05	
Molybdenum	No	1.54E-05	6.73E-05			1.54E-05	6.73E-05	
Nickel	Yes	2.93E-05	1.29E-04			2.93E-05	1.29E-04	Annual Ave
Selenium	Yes	9.63E-07	4.22E-06			9.63E-07	4.22E-06	
Vanadium	No	4.61E-05	2.02E-04			4.61E-05	2.02E-04	
Zinc	No	4.05E-04	1.77E-03			4.05E-04	1.77E-03	

HAPs Total **0.35** tpy

Notes:

[1] Facility-Wide Total generator pound per hour emissions excluded for modeling purposes.

TAP emissions from the emergency generators can be excluded from the modeling analysis because they will be addressed through 40 CFR 60 Subpart IIII and 40 CFR 63. Subpart ZZZZ Based on DEQ guidance memorandum dated July 25, 2013, C. Robinson, *"Per Idaho Air rules 201.20, Exclusion from Idaho TAPs Modeling for Stationary Engines subject to 40 CFR 60, Subparts IIII or JJJJ, and/or 40 CFR 63, Subpart ZZZZ"*

St Lukes Nampa Medical Center

Toxic Air Pollutants Emissions Screening

TAPs/HAPs	HAPs	Boilers 1-3	Screening Level (EL)	Requires Modeling
		(lb/hr)	(lb/hr)[1]	(Y/N)
2-Methylnaphthalene	No	1.01E-06	-	N
3-Methylchloranthrene	No	7.55E-08	2.50E-06	N
7,12-Dimethylbenz(a)anthracene	No	6.71E-07	-	N
Acenaphthene	No	7.55E-08	-	N
Acenaphthylene	No	7.55E-08	-	N
Anthracene	No	1.01E-07	-	N
Benzo(a)anthracene	No	7.55E-08	-	N
Benzene	**Yes**	8.80E-05	8.00E-04	N
Benzo(a)pyrene	No	5.03E-08	2.00E-06	N
Benzo(b)fluoranthene	No	7.55E-08	-	N
Benzo(g,h,i)perylene	No	5.03E-08	-	N
Benzo(k)fluoranthene	No	7.55E-08	-	N
Chrysene	No	7.55E-08	-	N
Dibenz(a,h)anthracene	No	5.03E-08	-	N
Dichlorobenzene	No	5.03E-05	2.00E+01	N
Ethylbenzene	**Yes**	1.10E-07	-	N
Fluoranthene	No	1.26E-07	-	N
Fluorene	No	1.17E-07	-	N
Formaldehyde	**Yes**	3.14E-03	5.10E-04	Y
Hexane	**Yes**	7.55E-02	1.20E+01	N
Indeno(1,2,3-cd)pyrene	No	7.55E-08	-	N
Naphthalene	**Yes**	2.56E-05	3.33	N
Phenanthrene	No	7.13E-07	-	N
Pyrene	No	2.10E-07	-	N
Toluene	**Yes**	1.43E-04	25	N
o-Xylene	**Yes**	1.88E-07	29	N
POM	**Yes**	4.78E-07	-	N
TAPs/HAPs Metals				
Arsenic	**Yes**	2.79E-06	1.50E-06	Y
Barium	No	6.15E-05	0.033	N
Beryllium	**Yes**	1.93E-07	2.80E-05	N
Cadmium	**Yes**	1.54E-05	3.70E-06	Y
Chromium	**Yes**	1.96E-05	0.033	N
Cobalt	**Yes**	1.17E-06	0.0033	N
Copper	No	1.19E-05	0.013	N
Manganese	**Yes**	5.31E-06	0.067	N
Mercury	**Yes**	3.63E-06	-	N
Molybdenum	No	1.54E-05	0.333	N
Nickel	**Yes**	2.93E-05	2.70E-05	Y
Selenium	**Yes**	9.63E-07	0.013	N
Vanadium	No	4.61E-05	3.00E-03	N
Zinc	No	4.05E-04	0.667	N

Notes:

[1] Screening level based on IDAPA 58.01.01.585 and 586.

TAP emissions from the emergency generators can be excluded from the modeling analysis because they will be addressed through 40 CFR 60 Subpart IIII and 40 CFR 63. Subpart ZZZZ

Based on DEQ guidance memorandum dated July 25, 2013, C. Robinson, "*Per Idaho Air rules 201.20, Exclusion from Idaho TAPs Modeling for Stationary Engines subject to 40 CFR 60, Subparts IIII or JJJJ, and/or 40 CFR 63, Subpart ZZZZ*"

St Lukes Nampa Medical Center

Greenhouse Gas Emissions Summary

Criteria Pollutants Emissions Unit Name	CO_2 Metric Tons/Yr	CO_2 Short Tons/Yr	N_2O Metric Tons/Yr	N_2O Short Tons/Yr	CH_4 Metric Tons/Yr	CH_4 Short Tons/Yr	CO2e Metric Tons/Yr	CO2e Short Tons/Yr
Gen 1	58	64	0.0005	0.0005	0.002	0.003	59	65
Gen 2	58	64	0.0005	0.0005	0.002	0.003	59	65
Gen 3	58	64	0.00047	0.0005	0.002	0.003	59	65
Gen 4	58	64	0.00047	0.0005	0.002	0.003	59	65
Boiler #1 (NG)	6,641	7,320	0.013	0.014	0.13	0.14	6,648	7,328
Boiler #1 (ULSD)	51	57	0.0004	0.0005	0.002	0.002	52	57
Boiler #2 (NG)	6,641	7,320	0.013	0.014	0.13	0.14	6,648	7,328
Boiler #2 (ULSD)	51	57	0.0004	0.0005	0.002	0.002	52	57
Boiler #3 (NG)	6,641	7,320	0.013	0.014	0.13	0.14	6,648	7,328
Boiler #3 (ULSD)	51	57	0.0004	0.0005	0.002	0.002	52	57
Total Facility Wide	**20,311**	**22,389**	**0.041**	**0.045**	**0.39**	**0.43**	**20,333**	**22,413**

Notes:

In June 2014, the Supreme Court partially invalidated EPA's GHG Tailoring Rule.

If a source exceeds major source thresholds for conventional criteria pollutants, then BACT for GHG shall be applied.

Since the St. Luke's Nampa facility is not a major source, it is not subject to GHG BACT requirements.

St. Lukes Nampa Medical Center - Emergency Generators

Generator Name Model No.	Caterpillar C27	
Engine Power Rating (kW)	800	
Engine Power Rating (hp)	1,214	
Fuel Type	Distillate #2	
- maximum sulfur content (%)	0.0015	ULSD
Maximum Firing Rate (gals/hr)*	57.30	Refer to gen data sheet at 100% load - column VFC
(MMBtu/hr)	8.02	
Maximum Hours of Operation	100	Assume: Uncontrolled PTE is equal to Controlled PTE
Maximum Firing Rate (gals/yr)	5,730	
Annual Maint Limit (hrs/yr)	100	
Heat Value of Fuel (Btu/gal)	140,000	AP42- Appendix A

Displacement 27.03 L

V-12, 4- Stroke
Cylinder Displacement 2.25

		Uncontrolled Potential to Emit			
Pollutant	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)
Total Particulate Matter (PM)[1,2]			0.12	12	0.006
Nitrogen Oxides (NOx)[1] as NO_2			16.63	1,663	0.83
Sulfur Oxides[3]		0.0015	0.012	1.2	0.001
Carbon Monoxide (CO)[1]			1.14	114	0.06
HC[1,4]			0.15	15	0.008

			Uncontrolled Potential to Emit		
Toxics[5]	CAS Number	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)
Benzene	71-43-2	7.76E-04	7.11E-05	6.23E-01	3.11E-04
Formaldehyde	50-00-0	7.89E-05	7.23E-06	6.33E-02	3.16E-05
Naphthalene	91-20-3	1.30E-04	1.19E-05	1.04E-01	5.21E-05
Toluene	108-88-3	2.81E-04	2.57E-05	2.25E-01	1.13E-04
o-Xylenes	1330-20-7	1.93E-04	1.77E-05	1.55E-01	7.74E-05
Acetaldehyde	75-07-0	2.52E-05	2.31E-06	2.02E-02	1.01E-05
Acrolein	107-02-8	7.88E-06	7.22E-07	6.32E-03	3.16E-06
Propylene	115-07-1	2.79E-03	2.55E-04	2.24E+00	1.12E-03
Acenaphthalylene	203-96-8	9.23E-06	8.45E-07	7.40E-03	3.70E-06
Acenaphthene	83-32-9	4.68E-06	4.29E-07	3.75E-03	1.88E-06
Fluorene	86-73-7	1.28E-05	1.17E-06	1.03E-02	5.13E-06
Phenanthrene	85-01-8	4.08E-05	3.74E-06	3.27E-02	1.64E-05
Anthracene	120-12-7	1.23E-06	1.13E-07	9.87E-04	4.93E-07
Fluoranthene	206-44-0	4.03E-06	3.69E-07	3.23E-03	1.62E-06
Pyrene	129-00-0	3.71E-06	3.40E-07	2.98E-03	1.49E-06
Benzo(g,h,i)pyrlene	191-24-2	5.56E-07	5.09E-08	4.46E-04	2.23E-07
Benz(a)anthracene	56-55-3	6.22E-07	5.70E-08	4.99E-04	2.49E-07
Benzo(b)fluoranthene	205-99-2	1.11E-06	1.02E-07	8.90E-04	4.45E-07
Benzo(k)fluoranthene	205-82-3	2.18E-07	2.00E-08	1.75E-04	8.74E-08
Chrysene	218-01-9	1.53E-06	1.40E-07	1.23E-03	6.14E-07
Dibenzo(a,h)anthracene	53-70-3	3.46E-07	3.17E-08	2.78E-04	1.39E-07
Indeno(1,2,3-cd)pyrene	193-39-5	4.14E-07	3.79E-08	3.32E-04	1.66E-07
Benzo(a)pyrene	50-32-8	2.57E-07	2.35E-08	2.06E-04	1.03E-07
Total PAH		2.12E-04	1.94E-05	1.70E-01	1.80E-06
POM [6]			4.12E-07	3.61E-03	3.36E-06

[1] PM, NOx, CO, and HC emission factors are derived from Caterpillar performance data

[2] PM emission factor is assumed to equal PM_{10} and $PM_{2.5}$

[3] SO_2 emission factor multiplied by percent sulfur content of fuel (EPA AP-42 Table 3.4-1) EF = 8.09E-03 x 0.0015 = 1.21E-05

[4] HC emission factor is used to equal VOCs.

[5] Toxic emission factors are derived from EPA AP-41, Table 3.4-3 and Table 3.4-4.

[6] POM (polycyclic organic matter) 7-PAH group, sum of benz(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, indeno(1,2,3-cd)pyrene, and benzo(a)pyrene

Note: Toxic emission factors derived from EPA AP-42 Tables 3.4-3 and 3.4-4.

GHG Emissions			
Pollutant[8]	Emissions (metric tons)	GWP[9]	CO_2e
CO_2	58.48	1	58.483
CH_4	0.0024	25	0.059
N_2O	0.00047	298	0.141
Total	58.49		58.68

For CO2, Use Equation C-1 from 40 CFR 98 Subpart C:
CO2 = 1x10-3 x Fuel x HHV x EF

CO2 = Annual CO2 mass emissions in Metric Tons	=	58.48
Fuel = Volume of fuel used (gallons)	=	5,730
HHV = High Heat Value from Table C-1 (mmBTU/short ton)	=	0.138
EFCO2 = Emission factor (kg/mmBTU)	=	73.96

For CH4 and N2O, Use Equation C-8 from 40 CFR 98 Subpart C:
CH4, N2O = 1x10-3 x Fuel x HHV x EF

CH4 = Annual CH4 mass emissions in Metric Tons	=	0.0024
N2O = Annual N2O mass emissions in Metric Tons	=	0.00047
Fuel = Volume of fuel used (gallons)	=	5,730
HHV = High Heat Value from Table C-1 (mmBTU/short ton)	=	0.138
EFCH4 = Emission factor (kg/mmBTU)	=	3.00E-03
EFCH4 = Emission factor (kg/mmBTU)	=	6.00E-04

Notes
[8] 40 CFR 98.32 - For stationary fuel combustion sources only, report CO2, CH4, and N2O
[9] GWP = Global Warming Potential - 40 CFR 98 Subpart A, Table A-1, revised 2013 GWP.

St. Lukes Nampa Medical Center - Boilers (Dual-fueled)

Boiler (MMBtu/hr)	14.25
Manufacturer	Hurst
Fuel Type (Primary)	Natural Gas
Fuel Type (Backup)	ULSD
Boiler Horsepower (BHP)	350
Maximum Heat Input Rating (Btu/hr)	11,717,650
Natural Gas*	
Maximum Operation Limit (hrs/yr)	8,760
Maximum Firing Rate (MMcf/yr)	122
Heat Value of NG (Btu/scf)	1,020
Maximum Firing Rate (MMcf/hr)	1.40E-02
Ultra Low Sulfur Diesel**	
Maximum Operating Limit (hrs/yr)	48
NG Operating Hours (hrs/yr)	8,712
Sulfur Content in Fuel (%)	0.0015
Maximum Fuel Usage (gal/hr)	105
Maximum Fuel Usage (gal/yr)	5,040
Heat Value of ULSD (Btu/gal)	140,000

* Note: Annual worst-case assumed 8712 annual hours of operation using natural gas + 48 hours using diesel fuel.

** Ultra low sulfur diesel (ULSD) is 0.0015% sulfur content

			NG Uncontrolled Potential to Emit[1]			ULSD Uncontrolled Potential to Emit[1]			Worst Case*		
Criteria Pollutant	Natural Gas Emission Factor (lb/10^6 BTU)[2]	ULSD Emission Factor (lb/Mgal)[3]	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)[4]	Emission Rate (lb/yr)[5]	Emission Rate (ton/yr)[5]	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)
Total Particulate Matter (PM)[6]	0.0048	2.0	0.068	596	0.30	0.210	10	0.01	0.210	606	0.3030
PM_{10}[6,7]	0.0048	1.0	0.068	596	0.30	0.105	5	0.00	0.105	601	0.3005
$PM_{2.5}$[6,7]	0.0048	0.25	0.068	596	0.30	0.026	1	0.00	0.068	597	0.2986
Nitrogen Oxides (NOx)	0.033	16.8	0.470	4,097	2.05	1.764	85	0.04	1.764	4,182	2.09
Sulfur Oxides	0.0016	0.2	0.022	196	0.10	0.022	1	0.001	0.022	197	0.10
Carbon Monoxide (CO)	0.037	5.0	0.527	4,594	2.30	0.525	25	0.01	0.527	4,619	2.31
VOC[8]	0.0250	0.252	0.356	3,104	1.55	0.026	1	0.00	0.356	3,105	1.55
Lead[9]			6.99E-06	0.061	3.04E-05	5.78E-07	2.77E-05	1.39E-08	6.99E-06	0.061	3.04E-05

				NG Uncontrolled Potential to Emit			ULSD Uncontrolled Potential to Emit			Worst Case		
Toxics	CAS No.	NG Emission Factor[10] (lb/10^6 scf)	ULSD Emission Factor[11] (lb/Mgal)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)[4]	Emission Rate (lb/yr)[5]	Emission Rate (ton/yr)[5]	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)
2-Methylnaphthalene	91-57-6	2.40E-05		3.35E-07	2.94E-03	1.47E-06	0	0	0	3.35E-07	2.94E-03	1.47E-06
3-Methylchloranthrene	56-49-5	1.80E-06		2.52E-08	2.20E-04	1.10E-07	0	0	0	2.52E-08	2.20E-04	1.10E-07
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05		2.24E-07	1.96E-03	9.79E-07	0	0	0	2.24E-07	1.96E-03	9.79E-07
Acenaphthene	83-32-9	1.80E-06	2.11E-05	2.52E-08	2.20E-04	1.10E-07	1.21E-08	1.06E-04	5.32E-08	2.52E-08	2.20E-04	1.10E-07
Acenaphthylene	203-96-8	1.80E-06	2.53E-07	2.52E-08	2.20E-04	1.10E-07	1.46E-10	1.28E-06	6.38E-10	2.52E-08	2.20E-04	1.10E-07
Anthracene	120-12-7	2.40E-06	1.22E-06	3.35E-08	2.94E-04	1.47E-07	7.02E-10	6.15E-06	3.07E-09	3.35E-08	2.94E-04	1.47E-07
Benzo(a)anthracene	56-55-3	1.80E-06	4.01E-06	2.52E-08	2.20E-04	1.10E-07	2.31E-09	2.02E-05	1.01E-08	2.52E-08	2.20E-04	1.10E-07
Benzene	71-43-2	2.10E-03	2.14E-04	2.93E-05	2.57E-01	1.29E-04	1.23E-07	1.08E-03	5.39E-07	2.93E-05	2.57E-01	1.29E-04
Benzo(a)pyrene	50-32-8	1.20E-06		1.68E-08	1.47E-04	7.34E-08	0	0	0	1.68E-08	1.47E-04	7.34E-08
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.48E-06	2.52E-08	2.20E-04	1.10E-07	8.52E-10	7.46E-06	3.73E-09	2.52E-08	2.20E-04	1.10E-07
Benzo(g,h,i)perylene	191-24-2	1.20E-06	2.26E-06	1.68E-08	1.47E-04	7.34E-08	1.30E-09	1.14E-05	5.70E-09	1.68E-08	1.47E-04	7.34E-08
Benzo(k)fluoranthene	205-82-3	1.80E-06	1.48E-06	2.52E-08	2.20E-04	1.10E-07	8.52E-10	7.46E-06	3.73E-09	2.52E-08	2.20E-04	1.10E-07
Chrysene	218-01-9	1.80E-06	2.38E-06	2.52E-08	2.20E-04	1.10E-07	1.37E-09	1.20E-05	6.00E-09	2.52E-08	2.20E-04	1.10E-07
Dibenz(a,h)anthracene	53.70-3	1.20E-06	1.67E-06	1.68E-08	1.47E-04	7.34E-08	9.61E-10	8.42E-06	4.21E-09	1.68E-08	1.47E-04	7.34E-08
Dichlorobenzene	25321-22-6	1.20E-03		1.68E-05	1.47E-01	7.34E-05	0	0	0	1.68E-05	1.47E-01	7.34E-05
Ethylbenzene	100-41-4		6.36E-05	0	0	0	3.66E-08	3.21E-04	1.60E-07	3.66E-08	3.21E-04	1.60E-07
Fluoranthene	206-44-0	3.00E-06	4.84E-06	4.19E-08	3.67E-04	1.84E-07	2.78E-09	2.44E-05	1.22E-08	4.19E-08	3.67E-04	1.84E-07
Fluorene	86-73-7	2.80E-06	4.47E-06	3.91E-08	3.43E-04	1.71E-07	2.57E-09	2.25E-05	1.13E-08	3.91E-08	3.43E-04	1.71E-07
Formaldehyde	50-00-0	7.50E-02	3.30E-02	1.05E-03	9.18E+00	4.59E-03	1.90E-05	1.66E-01	8.32E-05	1.05E-03	9.18E+00	4.59E-03
Hexane	110-54-3	1.80E+00		2.52E-02	2.20E+02	1.10E-01	0	0	0	2.52E-02	2.20E+02	1.10E-01
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	2.14E-06	2.52E-08	2.20E-04	1.10E-07	1.23E-09	1.08E-05	5.39E-09	2.52E-08	2.20E-04	1.10E-07
Naphthalene	91-20-3	6.10E-04	1.13E-03	8.52E-06	7.47E-02	3.73E-05	6.50E-07	5.70E-03	2.85E-06	8.52E-06	7.47E-02	3.73E-05
Phenanthrene	85-01-8	1.70E-05	1.05E-05	2.38E-07	2.08E-03	1.04E-06	6.04E-09	5.29E-05	2.65E-08	2.38E-07	2.08E-03	1.04E-06
Pyrene	129-00-0	5.00E-06	4.25E-06	6.99E-08	6.12E-04	3.06E-07	2.45E-09	2.14E-05	1.07E-08	6.99E-08	6.12E-04	3.06E-07
Toluene	108-88-3	3.40E-03	6.20E-03	4.75E-05	4.16E-01	2.08E-04	3.57E-06	3.12E-02	1.56E-05	4.75E-05	4.16E-01	2.08E-04
o-Xylene	1330-20-7		1.09E-04	0	0	0	6.27E-08	5.49E-04	2.75E-07	6.27E-08	5.49E-04	2.75E-07
POM[14]				1.59E-07	1.32E-03	6.61E-07	7.57E-09	6.63E-05	3.51E-08	1.59E-07	1.32E-03	6.61E-07

	NG Uncontrolled Potential to Emit	ULSD Uncontrolled Potential to Emit	Worst Case

St. Lukes Nampa Medical Center - Boilers (Dual-fueled)

Toxic-Metals	CAS Number	NG Emission Factor [12] ($lb/10^6$ scf)	ULSD Emission Factor [13] ($lb/10^{12}$ BTU)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr) [4]	Emission Rate (lb/yr) [5]	Emission Rate (ton/yr) [5]	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)
Arsenic	7440-38-2	2.00E-04	4.00E+00	2.79E-06	2.45E-02	1.22E-05	2.57E-07	2.25E-03	1.12E-06	2.79E-06	2.45E-02	1.22E-05
Barium	7440-39-3	4.40E-03		6.15E-05	5.39E-01	2.69E-04				6.15E-05	5.39E-01	2.69E-04
Beryllium	7440-41-7	1.20E-05	3.00E+00	1.68E-07	1.47E-03	7.34E-07	1.93E-07	1.69E-03	8.44E-07	1.93E-07	1.69E-03	8.44E-07
Cadmium	7440-43-9	1.10E-03	3.00E+00	1.54E-05	1.35E-01	6.73E-05	1.93E-07	1.69E-03	8.44E-07	1.54E-05	1.35E-01	6.73E-05
Chromium	7440-47-3	1.40E-03	3.00E+00	1.96E-05	1.71E-01	8.57E-05	1.93E-07	1.69E-03	8.44E-07	1.96E-05	1.71E-01	8.57E-05
Cobalt	7440-48-4	8.40E-05		1.17E-06	1.03E-02	5.14E-06				1.17E-06	1.03E-02	5.14E-06
Copper	7440-50-8	8.50E-04	6.00E+00	1.19E-05	1.04E-01	5.20E-05	3.85E-07	3.37E-03	1.69E-06	1.19E-05	1.04E-01	5.20E-05
Lead			9.00E+00				5.78E-07	5.06E-03	2.53E-06	5.78E-07	5.06E-03	2.53E-06
Manganese	7439-96-5	3.80E-04	6.00E+00	5.31E-06	4.65E-02	2.33E-05	3.85E-07	3.37E-03	1.69E-06	5.31E-06	4.65E-02	2.33E-05
Mercury	7439-97-6	2.60E-04	3.00E+00	3.63E-06	3.18E-02	1.59E-05	1.93E-07	1.69E-03	8.44E-07	3.63E-06	3.18E-02	1.59E-05
Molybdenum	7439-98-7	1.10E-03		1.54E-05	1.35E-01	6.73E-05				1.54E-05	1.35E-01	6.73E-05
Nickel	7440-02-0	2.10E-03	3.00E+00	2.93E-05	2.57E-01	1.29E-04	1.93E-07	1.69E-03	8.44E-07	2.93E-05	2.57E-01	1.29E-04
Selenium	7782-49-2	2.40E-05	1.50E+01	3.35E-07	2.94E-03	1.47E-06	9.63E-07	8.44E-03	4.22E-06	9.63E-07	8.44E-03	4.22E-06
Vanadium	1314-62-1	3.30E-03		4.61E-05	4.04E-01	2.02E-04				4.61E-05	4.04E-01	2.02E-04
Zinc	7440-66-6	2.90E-02	4.00E+00	4.05E-04	3.55E+00	1.77E-03	2.57E-07	2.25E-03	1.12E-06	4.05E-04	3.55E+00	1.77E-03

Notes:

[1] Uncontrolled emissions are equal to controlled emissions and are based on potential worst case

[2] PM, NOx, SOx, CO, and VOC emission factors obtained from Power Flame manufacturer.

[3] NOx emission factor for #2 fuel oil obtained from Power Flame Manufacturer. PM, $PM_{2.5}$, PM_{10}, SOx, CO, and VOC emission factors for industrial boilers firing No 2 Fuel oil use, EPA AP-42, Section 1.3, Tables 1.3-1, 1.3-3, and 1.3-6

[4] For ULSD, pound per hour emissions based on 48 hours of operation over 8,760 hours per year

[5] For ULSD, annual emissions based on 48 hours of operation over 8,760 hours per year

[6] For Natural Gas, PM emission factor equals PM10 and PM2.5

[7] For No 2 Fuel Oil, emission factors for PM, PM10, and PM2.5 come from Table 1.3-6.

[8] VOC are assumed to equal hydrocarbons per emission factors obtained from Power Flame manufacturer.

[9] Natural gas lead emissions based on 0.0005 $lb/10^6$ scf from small uncontrolled boilers (EPA AP-42, Section 1.4 Natural Gas Combustion, Tables 1.4-1 and 1.4-2).

[10] Toxic Air Pollutants (EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-3).

[11] Toxic Air Pollutants (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-9).

[12] Metals from Natural Gas Combustion (EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-4).

[13] Metals from Natural Gas Combustion (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-10).

[14] POM (Polycyclic organic matter) 7 PAH group is the sum of benz(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, indeno(1,2,3-cd)pyrene, and benzo(a)pyrene

GHG Emissions Compound [15]	NG Emissions (metric tons)	ULSD Emissions (metric tons)	GWP [16]	NG CO_2e	ULSD CO_2e
CO_2	6641.03	51.44	1	6641.03	51.44
CH_4	0.13	0.00	25	3.13	0.05
N_2O	0.013	0.000	298	3.73	0.12
Total	6641.17	51.44		6647.89	51.62

For CO2, Use Equation C-1 from 40 CFR 98 Subpart C:		ULSD & NG (ULSD)	(NG)
CO2 = 1x10-3 x Fuel x HHV x EF			
CO2 = Annual CO2 mass emissions in Metric Tons	=	51.44	6641.03
Fuel = Volume of fuel used (standard cubic feet)	=		121,728,847
Fuel = Volume of fuel used (gallons)	=	5,040	
HHV = High Heat Value from Table C-1 (mmBTU/short ton)	=	0.138	0.001028
EFCO2 = Emission factor (kg/mmBTU)	=	73.96	53.07
For CH4 and N2O, Use Equation C-8 from 40 CFR 98 Subpart C:			
CH4, N2O = 1x10-3 x Fuel x HHV x EF			
CH4 = Annual CH4 mass emissions in Metric Tons	=	0.0021	0.1251
N2O = Annual N2O mass emissions in Metric Tons	=	0.00042	0.01251
Fuel = Volume of fuel used (standard cubic feet)	=		121,728,847
Fuel = Volume of fuel used (gallons)	=	5,040	
HHV = High Heat Value from Table C-1 (mmBTU/short ton)	=	0.138	1.03E-03
EFCH4 = Emission factor (kg/mmBTU)	=	3.00E-03	1.00E-03
EFCH4 = Emission factor (kg/mmBTU)	=	6.00E-04	1.00E-04

Notes

[15] 40 CFR 98.32 - For stationary fuel combustion sources only, report CO2, CH4, and N2O

[16] GWP = Global Warming Potential - 40 CFR 98 Subpart A, Table A-1, revisions effective Jan 1, 2014.

St. Luke Nampa Medical Center Expansion

Wet Cooling Tower

Water Flow Rate (gal/min)	1,500	Design
Flow of cooling water (lbs/hr)	750,600	Calculated
TDS of blowdown (mg/l or ppmw) - Maximum ppm at blowdown	1,500	Design
Flow of dissolved solids (lbs/hr)	1,126	Calculated
Fraction of flow producing PM_{10} drift (See Note 2)	0.840	See Note 2
Control efficiency of drift eliminators (gal drift/gal flow)	0.000005	Design
PM emissions from tower (lb/hr)	0.006	Calculated
PM_{10} emissions from tower (lb/hr)	0.005	Calculated
PM emissions from tower (tpy)	0.025	Calculated
PM_{10} emissions from tower (tpy)	0.021	Calculated

Other Parameters

Number of cells per tower (outlet fans)	2	Two (2 cell) towers -4 total
Height at cell release (ft):	12.3	
Height at cell release (m):	3.75	
Discharge flow per cell (ACFM):	136,250	
Diameter of each cell (ft):	13.9	
Diameter of each cell (m):	4.24	
Area of cell discharge (ft^2):	152	
Average Temperature of cell discharge (degF):	77	
Average Temperature of cell discharge (K):	298.16	
Exit Velocity (ft/s):	15.0	
Exit Velocity (m/s):	4.56	

Notes:

(1) Cooling Tower design data from Kewiet.

(2) From "Calculating Realistic PM_{10} Emissions From Cooling Towers" (J. Reisman, G. Frisbie). Presented at 2001 AWMA Annual Meeting.

(3) TDS based on data from Idaho Power.

(4) Emission Calculation Method from AP 42, Sect.13.4-1

(5) Assume PM10 emissions equal PM2.5 emissions

St Lukes Nampa Medical Center

AERMOD Modeling Stack Parameters

Stack Name	Stack ID	Easting (meters)	Northing (meters)	Stack Height (Above Roof)	Diameter	Flow Rate	Temperature
				(ft)	(ft)	acfm	(K)
Gen 1	GEN1	533085.74	4829614.17	5	0.8333	14257	763
Gen 2	GEN2	533085.74	4829618.18	5	0.8333	14257	763
Gen 3	GEN3	533085.74	4829615.17	5	0.8333	14257	763
Gen 4	GEN4	533085.74	4829612.17	5	0.8333	14257	763
Boiler 1	BLR1	533064.57	4829624.18	10	1.667	4583	435.37
Boiler 2	BLR2	533064.57	4829620.18	10	1.667	4583	435.37
Boiler 3	BLR3	533064.57	4829616.17	10	1.667	4583	435.37
Cooling Tower 1A	CT1A	533083.74	4829640.65	12.30	13.94	136,250	298
Cooling Tower 1B	CT1B	533083.74	4829636.15	12.30	13.94	136,250	298
Cooling Tower 2A	CT2A	533083.74	4829630.65	12.30	13.94	136,250	298
Cooling Tower 2B	CT2B	533083.74	4829626.15	12.30	13.94	136,250	298

Notes:
Gen flowrate of 14,257 acfm = 133 m/s based on calculated flowrate
Converted boiler flow rates from manufacturer data sheet SCFM to ACFM (Appendix C).

St. Luke's Nampa Medical Center
PM Standard Calculations

Compliance with IDAPA Rule 677 PM Standard for Fuel Burning Equipment

Unit	Hurst Dual Fuel
Fuel	No. 2 Diesel
Rated Heat Input (MM Btu/hr)	14.25
PM Emission Rate (lb/hr)	0.21
Exit/Flue Gas Flowrate Calculation	
F_d (Table 19-2, EPA Method 19) (dscf/MM Btu) [1,2]	9,190
Exit flowrate @ 0% O_2: (acfm)	4,583
Exit flowrate @ 0% O_2: (dscfm)[5]	2,121
Exit flowrate @ 3% O_2 for Natural Gas: (dscfm) [3]	2,476
Calculated Grain Loading (gr/dscf @ 3% O_2) [4]	0.010
PM Loading Standard (IDAPA 58.01.01.677) (gr/dscf @ 3% 02)	0.050
Compliance w/ PM Loading Standard	Yes

[1] Appendix A-7 to 40 CFR part 60, Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates, Table 19-2 (F Factors for Various Fuels)

[2] Fd, Volumes of combustion components per unit of heat content (scf/million Btu). Fd for No. 2 diesel fuel is 9,190 dscf/106 Btu.

[3] (Flow $_{3\%}$) = (Flow $_{0\%}$)x (20.9/(20.9 - 3)), where 20.9 = Oxygen concentration in ambient air

[4] (Flow (dscfm) x (7,000 gr/lb) x (PM lb/hr) x (60 min/ hr) = gr/dscf

St. Luke's Nampa Medical Center
PM Standard Calculations

Compliance with IDAPA Rule 677 PM Standard for Fuel Burning Equipment

Unit	Hurst Dual Fuel
Fuel	Natural Gas
Rated Heat Input (MM Btu/hr)	14.25
PM Emission Rate (lb/hr)	0.07
Exit/Flue Gas Flowrate Calculation	
F_d (Table 19-2, EPA Method 19) (dscf/MM Btu) [1,2]	8,710
Exit flowrate @ 0% O_2: (acfm)	4,583
Exit flowrate @ 0% O_2: (dscfm)[5]	2,121
Exit flowrate @ 3% O_2 for Natural Gas: (dscfm) [3]	2,476
Calculated Grain Loading (gr/dscf @ 3% O_2) [4]	0.003
PM Loading Standard (IDAPA 58.01.01.677) (gr/dscf @ 3% 02)	0.050
Compliance w/ PM Loading Standard	Yes

[1] Appendix A-7 to 40 CFR part 60, Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates, Table 19-2 (F Factors for Various Fuels)

[2] Fd, Volumes of combustion components per unit of heat content (scf/million Btu). Fd for Natural gas fuel is 8710 dscf/106 Btu.

[3] $(Flow_{3\%}) = (Flow_{0\%}) \times (20.9/(20.9 - 3))$, where 20.9 = Oxygen concentration in ambient air

[4] (Flow (dscfm) x (7,000 gr/lb) x (PM lb/hr) x (60 min/ hr) = gr/dscf

[5] dscfm = acfm *(Standard Temp {R}) / (Stack Temp {R}) * (Stack Pressure {in Hg}) / (Standard Pressure {in Hg})

APPENDIX B – FRA BREAKDOWN

Title 40: Protection of Environment

Part 60, Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

§ 60.40c Am I subject to this subpart?

You are subject to this subpart if you own or operate a steam generating unit with a maximum design heat input rating of 10 to 100 million Btu/hr that was constructed, modified, or reconstructed since June 9, 1989.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

The facility proposes to install three (3) dual-fuel boilers, after June 9, 1989, with ratings of 14.25 MMBtu/hr. Each boiler is dual-fired and capable of combusting natural gas as the primary fuel or diesel as the secondary fuel.

Emission Standards for Operators

§ 60.42c What sulfur dioxide (SO_2) emission standards must I meet for natural gas and diesel fired boilers with a design heat input capacity input greater than 10 MMBtu/hr, but less than 100 MMBtu/hr?

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

Since the SLNMC boilers will utilize fuel oil as a secondary fuel source, this standard will apply. If distillate is burned you must submit a semi-annual report to EPA. The report must contain the following information: the calendar dates of the reporting period; and, a fuel "supplier" certification demonstrating fuel used does not exceed the sulfur content limitation of 0.5% by weight.

§ 60.43c What particulate matter (PM) emission standards must I meet for natural gas and diesel fired boilers with a design heat input capacity input greater than 10 MMBtu/hr, but less than 100 MMBtu/hr?

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

The PM Standard applies to boilers with a heat input capacity between 30 MMBtu/hr and 100 MMBtu/hr. Since the SLNMC boilers have a rated heat input capacity of 14.25 MMBtu/hr, the PM standard does not apply.

§ 60.44c Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions

Performance testing of the boilers will be conducted within 30 days after reaching maximum production, but within 180 days of initial startup.

Emission Monitoring Requirements

§ 60.46c Emission Monitoring for Sulfur Dioxide

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator

SLNMC will demonstrate that the fuel sulfur content is less than or equal to 0.5 percent by weight. The following procedures/methodologies will be used to demonstrate that all fuel supplied to the boiler meets the SO_2 standard. 1. Conduct ongoing shipment fuel sampling, including an initial performance test of the oil in the first fuel tank to be

fired in the steam generating unit, and fuel sampling analyses conducted after each shipment of oil is received and prior to its use in the boiler. OR 2. Obtain fuel supplier certifications for all fuel supplied to the boiler, and maintain certified statements that the fuel certifications represent all of the fuel combusted during the reporting period. Fuel supplier certifications will be maintained for at least two years and made available upon request.

Reporting and Recordkeeping Requirements

§ 60.48c What records are to be kept and what are the reporting requirements?

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

SLNMC will report and maintain records of their operations. Records must be maintained for at least two years. Records will include notification of the date of boiler construction or reconstruction, and anticipated and actual startup dates (within the timeframe specified in subpart A of the NSPS), including: 1) The design heat-input capacity of the boiler and identification of the fuels to be combusted in the boiler; 2) the annual capacity at which you anticipate operating the boiler based on all fuels fired and based on each individual fuel fired.

Records of the amounts of each fuel combusted during each day will be kept. Owners or operators that only burn very low (or ultra low) sulfur fuel oil (<15 ppm or .0015 weight percent sulfur) can record and maintain records of the fuels combusted during each calendar month instead of daily.

Since SLNMC is subject to SO_2 emission limits, they will submit a semi-annual (every 6 months) report as described in 60.48c(d). Reports will be postmarked by the 30th day following the end of the reporting period.

Facilities using the fuel supplier certification to demonstrate compliance with the SO_2 Standard must also submit the semi-annual report as described in Section 60.48c(e)(11). The report must include the following: 1) Calendar dates covered in the report period. 2) A certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represents all of the fuel combusted during the reporting period and; 3) Records of fuel supplier certifications for the reporting period.

The fuel supplier certification will state that the fuel oil complies with the specifications under the definition of distillate oil in Subpart Dc 60.41c.

Title 40: Protection of Environment

Part 60,Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

SLNMC will utilize four (4) emergency internal combustion engine generators. The engines are manufactured by Caterpillar, Model C27, and rated at 800 kW each (1214 HP rating). They are manufactured after 2011.

Emission Standards for Operators

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

800 kW rated emergency standby generators with total displacement = 27 liters/ 12 cylinders = 2.25 liter/cylinder. (See manufacturer data sheet in PTC application)

Comply with emission standards (Table 1 per 40 CFR 89.112): NHMC + NOx = 6.4 g/kw-hr; CO = 3.5 g/kw-hr; PM= 0.20 g/kw-hr (See emission calculations for emergency generators in PTC application)

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_X emissions by 90 percent or more, or limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

800 kW rated emergency standby generator with total displacement = 27 liters/ 12 cylinders = 2.25 liter/cylinder. (See manufacturer data sheet in PTC application)

Comply with emission standards (Table 1 per 40 CFR 89.112): NHMC + NOx = 6.4 g/kw-hr; CO = 3.5 g/kw-hr; PM= 0.20 g/kw-hr (See emission calculations for emergency generators in PTC application)

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

The emergency generators will be required to use ultra low sulfur diesel fuel with a maximum sulfur content of 15 ppmv.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

A non-resettable hour meter will be installed on each emergency generator.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and §60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial

operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Maintenance and testing hours of operation for the emergency generators will not exceed 100 hr/yr.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency

engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Title 40: Protection of Environment

Part 63, Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

SLNMC maintains and operates 4 emergency internal combustion engine installed after June 12, 2006. This facility is classified as an area source of HAP emissions defined as potential-to-emit (PTE) 10 tons per year (tpy) or less for any single HAP or PTE less than 25 tpy for total HAPs.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

Refer to the SLNMC applicability review per 40 CFR Part 60, Subpart IIII for the 4 emergency compression ignition engines.

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

40 CFR 63 Subpart JJJJJJ-National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

§63.11193 Am I subject to this subpart?

You are subject to this subpart if itou own or operate an industrial, commercial, or institutional boiler as defined in §63.11237 that is located at or is part al an area source of *hazardous air pollutants (HAP), as defined in* §63.2, *except as specified in §63.11195.*

The requirements of this subpart do not apply to St. Luke Nampa Medical Center (SLNMC) because the facility is an area source that owns and operates boilers that meet the excluded definitions in 40 CFR 63.11195.

§63.11195 Are any boilers not subject to this subpart?

The types of *boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.*

(a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.

(b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act.

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.

(d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research a n d development for the exemption to apply.

(e) A gas-fired boiler as defined in this subpart.

SLNMC will maintain boilers that satisfy the definition of gas-fired boilers in this section. Therefore, all of the SLNMC boilers are not subject to this subpart nor to any requirements in this subpart.

§63.11237 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in §63.2 (the General Provisions), and in this section as follows:

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

The SLNMC boilers will have the ability to fire both natural gas as the primary fuel and diesel fuel as backup. During an electric power failure event, diesel fuel will only be used in an emergency situation if the natural gas supply to the SLNMC is disrupted. SLNMC will limit periodic maintenance testing of diesel fuel to less than 48 hours per calendar year per boiler. Furthermore, SLNMC recommends a permit condition that monitors and records the hours of operation when using diesel fuel for maintenance testing.

APPENDIX C – MODELING PACKAGE

MEMORANDUM

DATE: August 16, 2016

TO: Tom Burnham, Permit Writer, Air Program

FROM: Darrin Mehr, Analyst, Air Program

PROJECT: P-2016.0011 PROJ 61684 – Permit to Construct (PTC) Application for St. Luke's Nampa Medical Center (SLNMC) for the Expansion Project at the Existing Facility in Nampa, Idaho

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs)

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Acronyms, Units, and Chemical Nomenclature

AAC	Acceptable Ambient Concentration of a Non-Carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
ACFM	Actual cubic feet per minute
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
ARM	Ambient Ratio Method
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
Btu/hr	British Thermal Units per hour
CFR	Code of Federal Regulations
CH2M	CH2M (St. Luke's permitting and modeling consultant)
CMAQ	Community Multi-Scale Air Quality Modeling System
CO	Carbon Monoxide
DEQ	Idaho Department of Environmental Quality
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
fps	Feet per second
GEP	Good Engineering Practice
hr	Hours
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
ISCST3	Industrial Source Complex Short Term 3 dispersion model
K	Kelvin
m	Meters
m/s	Meters per second
MMBtu	Million British Thermal Units
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Dataset
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
NEI	National Emissions Inventory
NWS	National Weather Service
O_3	Ozone
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	Parts Per Billion
PRIME	Plume Rise Model Enhancement
PTC	Permit to Construct
PTE	Potential to Emit
SIL	Significant Impact Level

SLNMC	St. Luke's Nampa Medical Center
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TASCO	The Amalgamated Sugar Company
tons/year	Ton(s) per year
T/yr	Tons per year
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VCU	Vapor Control Unit
VOCs	Volatile Organic Compounds
$\mu g/m^3$	Micrograms pr cubic meter of air

1.0 Summary

1.1 General Project Summary

On March 23, 2016, St. Lukes' Health Services (SLHS) submitted an application for a Permit to Construct (PTC) to expand the existing St. Luke's Nampa Medical Center (SLNMC) facility located at the corner of Midland Boulevard and Cherry Lane. The existing facility's emissions units were presumably exempt from air permit requirements. This project involved adding two cooling towers, each with two cells, three natural gas-fired boilers with backup distillate fuel capability, and four diesel-fired emergency generator engines.

Project-specific air quality impact analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to DEQ to demonstrate that the facility would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02 and 203.03 [Idaho Air Rules Section 203.02 and 203.03]). CH2M, SLSH's permitting and modeling consultant, submitted analyses and applicable information and data to enable DEQ to evaluate potential impacts to ambient air.

CH2M performed project-specific air quality impact analyses to demonstrate compliance for facility-wide allowable emissions with air quality standards. The DEQ review summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the pollutant dispersion modeling analyses used to demonstrate that the estimated emissions associated with operation of the facility as modified will not cause or significantly contribute to a violation of the applicable air quality standards. This review did not evaluate compliance with other rules or analyses that do not pertain to the air impact analyses. This modeling review also did not evaluate the accuracy of emissions estimates. Evaluation of emissions estimates was the responsibility of the permit writer and is addressed in the main body of the DEQ Statement of Basis.

The submitted air quality impact analyses: 1) utilized appropriate methods and models according to established DEQ/EPA rules, policies, guidance, and procedures; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that predicted pollutant concentrations from emissions associated with the facility as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or b) that predicted pollutant concentrations from applicable emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable National Ambient Air Quality Standards (NAAQS) at ambient air locations where and when the project has a significant impact; 5) showed that Toxic Air Pollutant (TAP) emissions increases associated with the project do not result in increased emissions and modeling was not required to demonstrate compliance with any TAPs increments. Table 1 presents key assumptions and results to be considered in the development of the permit.

Table 1. KEY CONDITIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	**Explanation/Consideration**
Potential to Emit for Modeling Exemptions The SLNMC expansion project qualified for an exemption from 24-hour and annual $PM_{2.5}$, 24-hour PM_{10} modeling requirements based on eliminating Boiler 4 from the proposed expansion project between modeling protocol stage and permit application submittal stages of this project.	Annual and 1-hour average NO_2 significant impact and NAAQS compliance demonstrations were the only criteria air pollutant ambient air dispersion analyses required for this project. $PM_{2.5}$ modeling requirements would have been triggered with the installation of the fourth boiler as part of this project.
Boiler Backup Distillate Fuel Oil Firing Testing and Maintenance Operations Boilers 1, 2, or 3 may be operated for testing and maintenance purposes on an individual basis at any time during the day or night for any duration. Concurrent operation of two or more boilers on distillate fuel was not represented in the modeling setup and the permit writer should consider a permit operating restriction that disallows concurrent boiler testing on distillate fuel.	An emission rate attributed to a single boiler operating on distillate fuel oil was modeled for 24 hours per day. Concurrent testing and maintenance operations would require the boilers to be modeled at the distillate fuel oil NOx emission rate. Each boiler operating on distillate fuel oil would be modeled at the 1.764 lb/hr of total NOx emission rate. NOx emissions for each boiler while fired on distillate fuel oil are 1.764 pounds per hour (lb/hr) versus 0.47 lb/hr while fired on natural gas at rated heat input capacity.
Generator Engine Testing Annual hours of operation were 100 hours per year for each of the four emergency generator engines, which reflects the annual limitation regarded by DEQ permitting staff for potential to emit on an annual basis.	Emergency generator engines are exempted from modeling per DEQ policy for compliance with the 1-hour NO_2 standard. The engines were appropriately modeled for 100 hours per year for the annual NO_2 NAAQS.

Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses demonstrated to the satisfaction of the Department, using DEQ/EPA established guidance, policies, and procedures, that operation of the proposed facility or modification will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

1.2 Summary of Submittals and Actions

November 9, 2015: CH2M submitted a modeling protocol via email.

December 11, 2015: CH2M submitted a modeling protocol addendum requesting the use of alternative 1-hour average NO_2 ambient background concentrations. The backgrounds would vary diurnally and seasonally and would be based on DEQ's hourly NO_2 monitoring data from the Meridian near-road monitor. This alternative background would affect the St. Luke's Nampa and ON Semiconductor Nampa permitting projects.

February 2, 2016: DEQ provided comments on the development of the alternative backgrounds to CH2M via email.

February 3, 2016: DEQ issued a modeling protocol approval letter with comments. The alternative ambient 1-hour backgrounds had not been approved at this time and approval was intended to be issued under separate letter prior to St.

	Luke's submittal of the permit application.
February 4, 2016:	DEQ provided comments and initial approval of the alternative 1-hour NO2 seasonal diurnal background dataset. Final approval is pending a more thorough review with the submittal of the formal application.
March 23, 2016:	St. Luke's submitted a PTC application.
April 20, 2016:	DEQ declared the application incomplete with comments.
May 13, 2016:	St. Luke's submitted a response to DEQ's incompleteness determination.
June 10, 2016:	DEQ declared the application complete.
August 5, 2016:	DEQ issued the facility draft permit package to St. Luke's for review and comment.

2.0 Background Information

2.1 Permit Requirements for Permits to Construct

PTCs are issued to authorize the construction of a new source or modification of an existing source or permit. Idaho Air Rules Section 203.02 requires that emissions from the new source or modification not cause or significantly contribute to a violation of an air quality standard, and Idaho Air Rules Section 203.03 requires that emissions from a new source or modification comply with applicable toxic air pollutant (TAP) increments of Idaho Air Rules Sections 585 and 586.

2.2 Project Location and Area Classification

The facility is located in Nampa, Idaho, in Canyon County. The area is designated as attainment or unclassifiable for all pollutants.

2.3 Modeling Applicability for Criteria Pollutants

2.3.1 Below Regulatory Concern and DEQ Modeling Guideline Level I and II Thresholds

Idaho Air Rules Section 203.02 state that a PTC cannot be issued unless the application demonstrates to the satisfaction of DEQ that the new source or modification will not cause or significantly contribute to a NAAQS violation. Atmospheric dispersion modeling is used to evaluate the potential impact of a proposed project to ambient air and demonstrate NAAQS compliance. However, if the emissions associated with a project are very small, project-specific modeling analyses may not be necessary.

If the emissions increases associated with a project are below modeling applicability thresholds established in the *Idaho Air Modeling Guideline* ("State of Idaho Guideline for Performing Air Quality Impact Analyses," available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf, then a project-specific analysis is not required. Modeling applicability emissions thresholds were developed by DEQ based on modeling of a hypothetical source and were designed to reasonably ensure that impacts are below the applicable SIL. DEQ has established two threshold levels: Level 1 thresholds

are unconditional thresholds, requiring no approval for use by DEQ; Level 2 thresholds are conditional upon DEQ approval, which depends on evaluation of the project and the site, including emissions quantities, stack parameters, number of sources emissions are distributed amongst, distance between the sources and the ambient air boundary, and the presence of sensitive receptors near the ambient air boundary. Level I model thresholds are applicable to the SLNMC project due to the proximity of ambient air to the modeled emissions sources. There is no setback distance from the sources to the discrete receptors representing ambient air in these ambient air impact analyses.

Certain pollutants were exempted from this permitting action's air impact analyses. If project-wide potential to emit (PTE) values for criteria pollutants would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of one or more criteria pollutants exceeding the BRC threshold of 10 percent of emissions defined by Idaho Air Rules as significant, then an air impact analysis may not be required for those pollutants. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules Section 221 is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant.[1]" The interpretation policy also states that the exemption criteria of uncontrolled PTE not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year. Table 2 presents the BRC modeling applicability for this project.

Table 2. CRITERIA POLLUTANT NAAQS COMPLIANCE DEMONSTRATION APPLICABILITY

Criteria Pollutant	Below Regulatory Concern Level (ton/year)	Applicable Facility-Wide Potential Emissions (ton/year)	NAAQS Compliance Exempted per BRC Policy?
PM_{10} [a]	1.5	0.97	Yes
$PM_{2.5}$ [b]	1.0	0.96	Yes
Carbon Monoxide (CO)	10.0	7.16	Yes
Sulfur Dioxide (SO_2)	4.0	0.30	Yes
Nitrogen Oxides (NOx)	4.0	9.60	No
Lead (Pb)	0.06	9.1E-05	Yes
Ozone as VOC or NOx	4.0	4.69 T/yr VOCs	No

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

Emissions of NOx exceeded the BRC threshold and the Level I total NOx modeling threshold for 1-hour NO_2 of 0.20 lb/hr and annual average NOx Level I modeling threshold of 1.2 ton/year. Modeling was required for the 1-hour and annual NO_2 SIL and NAAQS.

Emissions of VOCs exceeded the BRC threshold of 4.0 T/yr. Level I modeling thresholds for emissions of VOCs for ozone formation do not exist. Section 2.3.2 discusses modeling requirements for ozone modeling.

2.3.2 Ozone Modeling Applicability

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NO_x, and sunlight.

Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Addressing secondary formation of O_3 has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

Allowable emissions estimates of VOCs at 4.7 tons/year and NOx at 9.6 tons/year are well below the 100 tons/year threshold, and DEQ determined it was not appropriate or necessary to require a quantitative source specific O_3 impact analysis.

2.3.3 Secondary Particulate Formation Modeling Applicability

The impact from secondary particulate formation resulting from emissions of NOx, SO_2, and/or VOCs was assumed by DEQ to be negligible on the basis of the magnitude of emissions and the short distance from emissions sources to modeled receptors where maximum PM_{10} and $PM_{2.5}$ impacts would be anticipated.

2.4 Significant and Cumulative NAAQS Impact Analyses

If maximum modeled pollutant impacts to ambient air from emissions sources associated with a new facility or the emissions increase associated with a modification exceed the SILs of Idaho Air Rules Section 006 (referred to as a significant contribution in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02. A cumulative NAAQS impact analysis may also be required for permit revisions driven by compliance/enforcement actions, any correction of emissions limits or other operational parameters that may affect pollutant impacts to ambient air, or other cases where DEQ believes NAAQS may be threatened by the emissions associated with the facility or proposed project.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts, according to established DEQ/EPA guidance, policies, and procedures, from applicable facility-wide emissions and emissions from any nearby co-contributing sources. A DEQ-approved

background concentration value is then added to the modeled result that is appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 3. Table 3 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis.

Table 3. APPLICABLE REGULATORY LIMITS

Pollutant	Averaging Period	Significant Impact Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years. The O_3 standard was revised (the notice was signed by the EPA Administrator on October 1, 2015) to 70 ppb. However, this standard will not be applicable for permitting purposes until it is incorporated by reference *sine die* into Idaho Air Rules.

If the cumulative NAAQS impact analysis shows a violation of the standard, the permit cannot be issued if the proposed project or facility has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. The facility or project

does not have a significant contribution to a violation if impacts are below the SIL at all specific receptors showing violations during the time periods when modeled violations occurred.

Compliance with Idaho Air Rules Section 203.02 is demonstrated if: a) specific applicable criteria pollutant emissions increases are at a level defined as Below Regulatory Concern (BRC), using the criteria established by DEQ regulatory interpretation[1]; or b) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or c) modeled design values of the cumulative NAAQS impact analysis (modeling applicable emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP. The DEQ permit writer evaluates the applicability of specific TAPs to the Section 210.20 exclusion. TAPs modeling was not triggered for this project.

3.0 Analytical Methods and Data

3.1 Modeling Methodology

This section describes the modeling methods used by the applicant's consultant, CH2M, to demonstrate compliance with applicable air quality standards.

3.1.1 Overview of Analyses

CH2M performed project-specific air impact analyses that were determined by DEQ to be reasonably representative of the facility, using established DEQ policies, guidance, and procedures. Results of the submitted analyses, in combination with DEQ's analyses, demonstrated compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 4 provides a brief description of parameters used in the modeling analyses.

Table 4. MODELING PARAMETERS

Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Nampa, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 15181.
Meteorological Data	Boise	2011-2015—See Section 3.3 of this memorandum. Surface data from the Boise airport and upper air data from Boise, Idaho.
Terrain	Considered	Receptor, building, and emissions source stack base elevations were determined using USGS 1/3 arc second National Elevation Dataset (NED) files based on the NAD83 datum. The facility is located within Zone 11.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the facility and numerous nearby structures.
Receptor Grid	**Criteria Air Pollutants and Toxic Air Pollutants**	
	Grid 1	4-meter minimum to 25-meter maximum spacing along the perimeter walls of the facility's buildings.
	Grid 2	10-meter spacing along the facility's ambient air boundary which is all areas immediately exterior to the facility's buildings and outward in a 350-meter (x) by 430-meter (y) rectangular grid roughly centered on the facility's buildings.
	Grid 3	100-meter spacing in a 2,200-meter (x) by 2,300-meter (y) rectangular grid centered on Grid 2.
	Grid 4	500-meter spacing in a 10,500-meter (x) by 11,000-meter (y) rectangular grid centered on Grid 3.

3.1.2 Modeling Protocol

A modeling protocol was submitted to DEQ on November 9, 2015. On December 11, 2015, CH2M submitted a protocol addendum to request the use of alternative 1-hour NO_2 ambient background values. DEQ issued a modeling protocol approval, with comments, on February 3, 2016. A tentative approval of the alternative 1-hour NO_2 background concentrations was provided via email on February 9, 2016, with final approval withheld pending review of the permit application's air impact analyses.

Project-specific modeling was conducted using data and methods described in the modeling protocol and the *Idaho Air Modeling Guideline*[2].

3.1.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple-source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD Version 15181 was used by CH2M for the modeling analyses to evaluate impacts of the facility. This is the current version of this regulatory guideline model.

NO_2 1-hour impacts can be assessed using a tiered approach to account for $NO/NO_2/O_3$ chemistry. Tier 1 assumes full conversion of NO to NO_2. Tier 2 ARM assumes a 0.80 default ambient ratio of NO_2/NO_x for 1-hour NO_2 and 0.75 for annual average NO_2.

Tier 2 ARM2 is a more refined method of estimating the conversion of NO to NO_2 for the 1-hour NO_2 standard than the established Tier 2 ARM. Tier 2 ARM2 relies on a considerable body of EPA Air Quality System (AQS) monitoring data analyzing the NO_2/NO_x ratios of the nationwide data. As described in the underlying technical paper submitted to EPA[3] and EPA's related guidance,[4] the nationwide EPA data was separated into groups or "bins" of data values spaced in increments of 10 parts per billion (ppb) where NOx monitoring values were less than 200 ppb and 20 ppb "bins" for values greater than 200 ppb. Within each 10 ppb and 20 ppb bin, the 98th percentile value for the NO_2/NO_x ratio was determined and used in the dataset to create a sixth order polynomial regression equation that is used to calculate a NO_2/NO_x ratio based on total NO_x.

Tier 3 is a more refined assessment of the NO to NO_2 conversion, using a supplemental modeling program with AERMOD to better account for $NO/NO_2/O_3$ atmospheric chemistry. Either the Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limiting Method (OLM) can be specified within the AERMOD input file for the Tier 3 approach. EPA guidance (Memorandum: from Tyler Fox, Leader, Air Quality Modeling Group, C439-01, Office of Air Quality Planning and Standards, USEPA; to Regional Air Division Directors. *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard.* March 01, 2011) has not indicated a preference for one option over the other (PVMRM vs OLM) for particular applications. The Tier 2 ARM2 and both Tier 3 methods are considered to be non-regulatory guideline methods and must be approved by DEQ for the applicant's use on a case-by-case basis. CH2M elected to use a Tier 2 ARM2 approach for the 1-hr NO_2 NAAQS analyses.

DEQ approved the use of the Beta algorithms for treatment of point sources with horizontal release orientation or equipped with a rain cap that impedes the vertical momentum of exhaust plumes. Thermal buoyancy with regard to the temperature of the plume is still accounted for with this method.

Tier 2 ARM2 NO_2 Method Justification for Use

The Tier 2 ARM2 approach is generally considered to be conservative compared to Tier 3 methods, provided certain criteria are met. EPA's current guidance[4] prescribes the process that should be used for evaluation and agency approval of ARM2 for use in a 1-hour NO_2 NAAQS compliance demonstrations.

CH2M provided justification for use of the ARM2 method for this project in the permit application modeling report. The justification for use of the method included an AERMOD analysis of the expansion project's Tier 1 NO_2 impacts. DEQ determined the information contained in the modeling report was an appropriate justification for use of the Tier 2 ARM2 method.

Section 3.2.6 of EPA's September 30, 2014, guidance memorandum[4] provides a succinct summary of a four-part framework to demonstrate that the Tier 2 ARM2 method is appropriate for the 1-hour NO^2 modeling analysis. CH2M's modeling report justification points for each of the criteria are described below:

1. **EPA Criteria from Memorandum:**
   Impacts from the "primary source" are less than 150 to 200 ppb (equal to 282 micrograms/cubic meter ($\mu g/m^3$) to 360 $\mu g/m^3$) when using the Tier 1 method of total conversion (all NOx is NO_2).

   The justification for Tier 2 ARM2 should include a Tier I impact analysis that assumes 100% conversion of NO to NO_2 (no application of ARM2). The modeled impacts used for evaluation, as specified in current EPA Modeling Clearinghouse memoranda, are based on the NO_2 design value of the NAAQS, which is the maximum of 8^{th} highest maximum daily 1-hour impacts.

   CH2M Documentation:
   A Tier 1 NO_2 modeling analysis was performed and the highest 8^{th} high of maximum daily 1-hour modeled values over the 5-year period was 160.8 $\mu g/m^3$. This is below the minimum appropriateness threshold of 282 $\mu g/m^3$.

2. **EPA Memorandum:**
   If the total predicted NOx from a Tier 1, total conversion, analysis exceeds the 150-200 ppb threshold recommended above, then the representative background NO_2 concentration may also be considered to justify a higher NOx threshold. If representative background NO_2 levels are generally low (less than about 20-30 ppb), then it may be appropriate to consider a higher NOx threshold to justify use of ARM2.

   DEQ Comment:
   The SLNMC project's Tier I impact was below the 150 ppb (or 282 $\mu g/m^3$) minimum threshold value. This condition does not affect CH2M's request.

3. **EPA Memorandum:**
   If the total NOx from a Tier 1 total conversion analysis exceeds the 150-200 ppb threshold outlined above, then the NO2/NOx In-Stack Ratio (ISR) of the primary source should be considered. If the primary source has ISRs that are all below 0.2, then ARM2 should be appropriately conservative for a Tier 2 analysis. If the source has a known ISR greater than 0.2, then ARM2 may be used, but the minimum ARM2 ratio should be adjusted to match the source's ISR. If a source has multiple stacks with varying ISRs, then nominally, the minimum ARM2 ratio should be set to the maximum source ISR.

   CH2M Documentation:
   Use of a minimum NO_2/NO_X in stack ratio (ISR) of 0.5 could be used for the ARM2 method without further addressing the ISR for the facility's sources. The 0.5 value will

be used as the ARM_MIN value in the AERMOD setup for the SLNMC modeling.

DEQ Comment:
Use of the 0.5 NO_2/NO_x ratio is conservative and negates any need for additional substantiation.

4. **EPA Memorandum:**
EPA conducted sensitivity analyses to evaluate the threshold where the Tier 2 ARM2 method NO_2/NO_x ratios are less conservative than the Tier 3 OLM, Tier 3 PVMRM, or actual NO_2/NO_x ratios. EPA concluded that the ARM2 method would not be appropriate if the background ozone is frequently (more than seven days per year) greater than 80 to 90 ppb during a typical year.

CH2M Documentation:
Taken from Section 5.8 of the SLNMC project's modeling report:
"The area around the project site has ozone levels that are not persistently above approximately 80-90 ppb, specifically the modeled 1-hour value provided by DEQ was 60 ppb."

DEQ Comment:
The 60 ppb value provided by DEQ was obtained from the NW AIRQUEST ambient background lookup tool and is applicable to Tier 3 NO_2 modeling demonstration methods rather than as a validation that ambient ozone concentrations were not persistently greater than 80 to 90 ppb. CH2M's justification does not address the actual monitoring data in the immediate vicinity of this Nampa facility; however, DEQ has determined that based on recent ozone monitoring data from the Meridian, Idaho monitoring site, ozone levels are not persistently above EPA's threshold range of 80-90 ppb criteria over 8 days or more within a typical year.

DEQ concurs that the SLNMC project qualifies for use of the Tier 2 ARM2 method, based on the request for authorization and justification materials presented to DEQ in the modeling report. Approval is also support by DEQ's current knowledge of ambient ozone values in the area surrounding the proposed facility and the current EPA concurrence memoranda presented in the Modeling Clearinghouse Information Storage and Retrieval System, located on EPA's website at the following address: https://cfpub.epa.gov/oarweb/MCHISRS/.

Specific Clearinghouse memoranda are linked to the MCHISRS site on EPA's Support Center for Regulatory Atmospheric Modeling (SCRAM) at the following EPA webpage under the "Recent Additions" header: https://www3.epa.gov/ttn/scram/.

3.2 Background Concentrations

A background concentration tool was used to establish ambient background concentrations for this project. A beta version of the background concentration tool was developed by the Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST) and provided through Washington State University (located at http://lar.wsu.edu/nw-AIRQUEST/lookup.html). The tool uses regional scale modeling of pollutants in Washington, Oregon, and Idaho, with modeling results adjusted according to available monitoring data. The background concentration is added to the design value for each pollutant and averaging period. The ambient background annual averaged NO_2 value for the SLNMC facility's location is10.9 $\mu g/m^3$.

CH2M formally requested that DEQ approve of the use of an alternative 1-hour NO_2 ambient background dataset. The dataset was developed based on available hourly monitoring data from the Meridian, Idaho, near-road monitor. The EPA Air Quality System (AQS) site ID number is 160010023, and the address for the site is 1311 East Central Drive, Meridian, Idaho. There are two co-located NO_2 monitors at this location. Both are approved monitors for developing NAAQS compliance monitoring data.

The seasons are assigned the following months:

Winter:	December, January, and February
Spring:	March, April, and May
Summer:	June, July, and August
Fall:	September, October, and November.

CH2M developed a seasonal background value that was calculated as the arithmetic mean of three individual years of data. An hourly (diurnal) approach was applied to accurately characterize the variation in NO_2 background concentrations over the course of each day. The seasonal approach further enhanced the background to more accurately reflect the variation that exists over each season within the year.

The final dataset of background concentrations used in the 1-hour NO_2 analysis for this project is listed in Table 5.

Table 5. SEASONAL DIURNAL 1-HOUR NO_2[a] BACKGROUND CONCENTRATIONS

Hour of Day	1-hour NO_2, units of ppb[b]			
	Winter	Spring	Summer	Autumn
1 (12 am to 1 am)	30.6	26.3	23.7	24.3
2	28.6	21.8	18.5	21.6
3	26.7	20.6	17.5	21.0
4	25.8	23.9	21.3	22.3
5	26.9	26.2	24.2	22.1
6	28.2	27.2	27.3	25.3
7	29.1	31.8	30.0	28.4
8	29.8	32.4	26.0	30.3
9	31.1	27.1	23.7	26.5
10	26.9	22.2	20.0	24.3
11	25.9	18.5	19.7	21.5
12	24.6	16.6	15.5	17.9
13	20.0	15.7	14.3	17.1
14	18.0	16.6	13.6	16.3
15	20.9	15.7	16.0	18.0
16	22.5	15.7	16.6	21.0
17	23.7	17.1	17.7	23.3
18	28.0	18.4	17.4	28.6
19	32.6	24.3	20.6	34.6
20	35.1	32.5	30.9	41.4
21	34.4	40.1	41.4	39.6
22	33.7	39.2	40.0	34.6
23	32.4	35.3	35.7	31.5
24	32.0	31.5	31.1	26.5

a. Nitrogen oxides.
b. Parts per billion.

DEQ requested that CH2M use complete seasons for each of the three years of data that were to be included in the ambient background population of data. Monitoring at the Meridian Near-Road site for calendar year 2012 began on April 1, 2012 rather than January 1, 2012. The valid data collected by DEQ for the two monitors at this site was provided to CH2M in an email dated February 2, 2016. The text of DEQ's February 2, 2016, email to CH2M is provided in Attachment A to this memorandum.

DEQ requested that CH2M use the 98th percentile value as the design value for each season of each year. The average of the three individual annual 98th percentile values established the design value for each hour of the day. Where data completeness for an individual season fell below 90.0%, DEQ requested that the individual year seasonal design value be based on the 2nd rank value. CH2M accommodated this request for the following: June, July, and August 2013; December 2013, January 2014, and February 2014; Winter 2014 season design values already used the 2nd rank value.

A correction was made to the March 23, 2016, modeling analyses' "ON-Semi AQDM Season-Hour v7.xlsx" spreadsheet. This version of the spreadsheet was the version tentatively approved by DEQ in a February 4, 2016 email. Under the "ALL YRS" tab of this spreadsheet, the Summer Season diurnal design values for Hours 1 through 24 for input in the AERMROD model are contained in the "3-YR Summer AVG" row. The design values for Hours 2 through 24 were based on the average of 2013 and 2014 summer season values only. The calculation of average values was corrected by CH2M in what is referred to as version 8 of the spreadsheet.

The May 13, 2016 submitted air impact analyses contained a spreadsheet titled "ON-Semi AQDM Season-Hour v8.xlsx." This spreadsheet included CH2M's final version of the alternative 1-hour NO_2 ambient background values varying seasonally and diurnally. This version of the spreadsheet contains the DEQ-approved 1-hour NO_2 background concentrations for this project.

3.3 Meteorological Data

DEQ provided CH2M with a model-ready meteorological dataset processed from Boise airport surface and Boise upper air meteorological data covering the years 2011-2015. The model-ready dataset for this project was generated from monitored data collected at the Boise airport (FAA airport code KBOI) for surface and Automated Surface Observing System (ASOS) data and upper air data from the National Weather Service (NWS) Station site (site ID 726810-24131). Surface characteristics were determined by DEQ staff using AERSURFACE version 13016. DEQ modeling staff evaluated annual moisture conditions for the AERSURFACE runs based on thirty years of Boise airport precipitation data. Conditions were determined to be "wet" for 2014 only. 2011-2013 and 2015 were determined to be "average" years for precipitation. Continuous snow cover at the Boise airport site was determined to not have existed during any period from 2011-2015. AERMINUTE version 15271 was used to process ASOS wind data for use in AERMET. AERMET Version 15181 was used to process surface and upper air data and to generate a model-ready meteorological data input file. DEQ determined these data were representative for the Nampa SLNMC site and approved use of this dataset for the project.

3.4 Terrain Effects

CH2M used a National Elevation Dataset (NED) file in "tif" format in the WGS84 datum, to calculate elevations of receptors. The model setup was converted to NAD83 coordinates in the AERMOD model setup. A 1/3rd arc second file provided 10-meter resolution of elevation data. The terrain preprocessor AERMAP version 11103 was used to extract the elevations from the NED file and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also

determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

3.5 Building Downwash Effects on Modeled Impacts

Potential downwash effects on the emissions plume were accounted for in the model by using building parameters as described by CH2M. The Building Profile Input Program for the PRIME downwash algorithm (BPIP-PRIME) was used to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and release parameters for input to AERMOD. All modeled structures are depicted in Figures 2 and 3 of the SLNMC permit application. Building and stack source base elevations were determined using the AERMAP program.

DEQ review concluded that the building downwash was appropriately evaluated.

3.6 Facility Layout

Figures 1 and 2 below show the facility's emission sources and all structures in the modeling analyses. Ambient air is considered to exist anywhere exterior to the facility's buildings. Two new structures will be built as a result of this permitting action. An expansion wing will be added to the existing building and a separate central plant will be constructed to house all of the project's emissions units. The Central Plant building will house three boilers, four emergency generator engines, and two cooling towers (each tower is equipped with two cells).

Google earth imagery for this site is dated April 1, 2016, so the new construction associated with this project is clearly visible. The facility's structure locations and horizontal dimensions matched the web-based mapping program Google earth® relatively well except for a couple of points. The eastern end of the expansion building and a section on the northern portion of the expansion building adjacent to the Central Plant building dimensions did not match photographic documentation. DEQ noted that the Central Plant building was constructed closer to the Cherry Lane road than represented in the modeling setup. Ambient air is considered everywhere external to the buildings so the ambient impact analyses were not affected because the distance from the emissions sources to discrete receptors remains the same.

Figure 1. ST. LUKE'S NAMPA MEDICAL CENTER LAYOUT

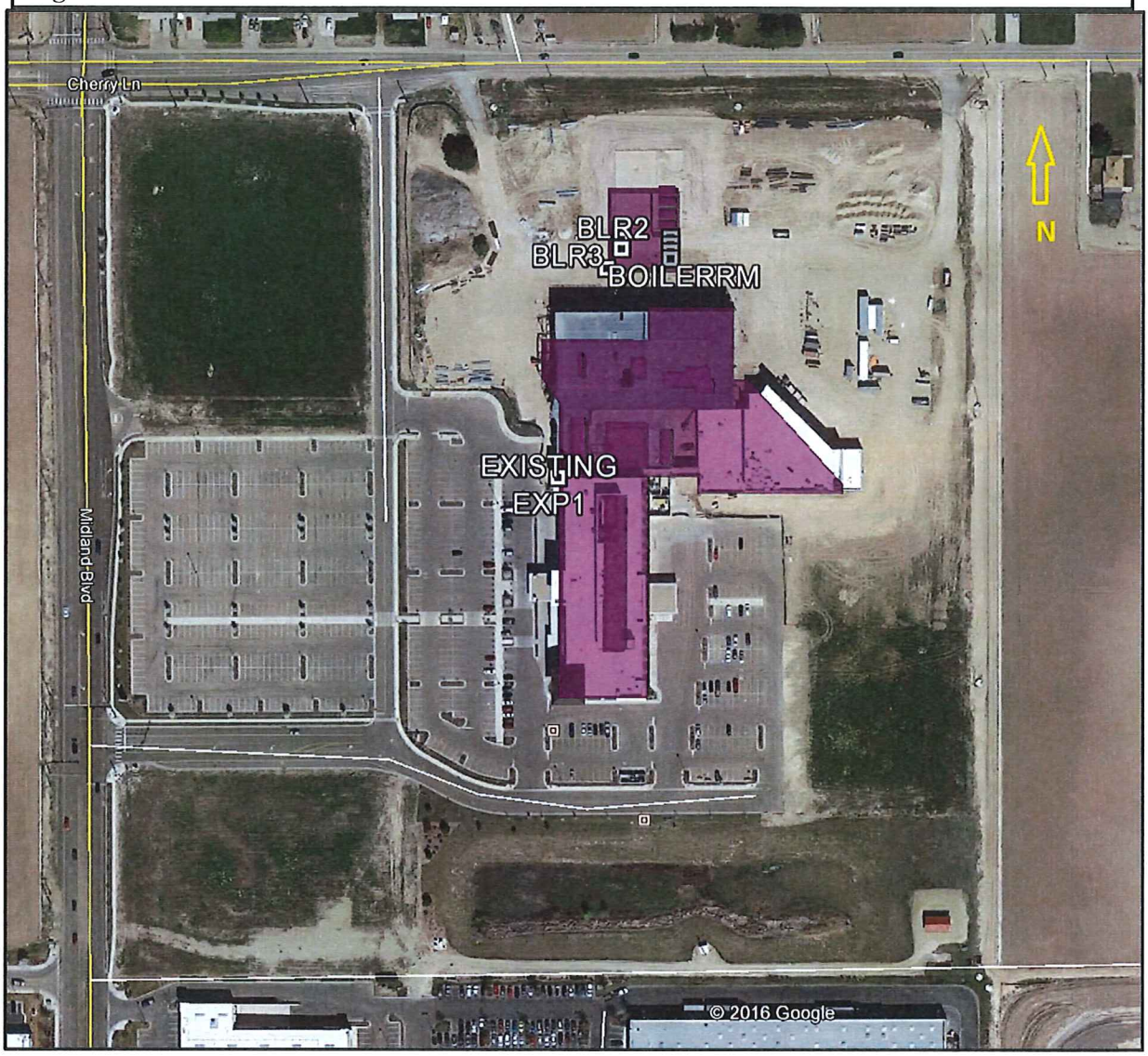
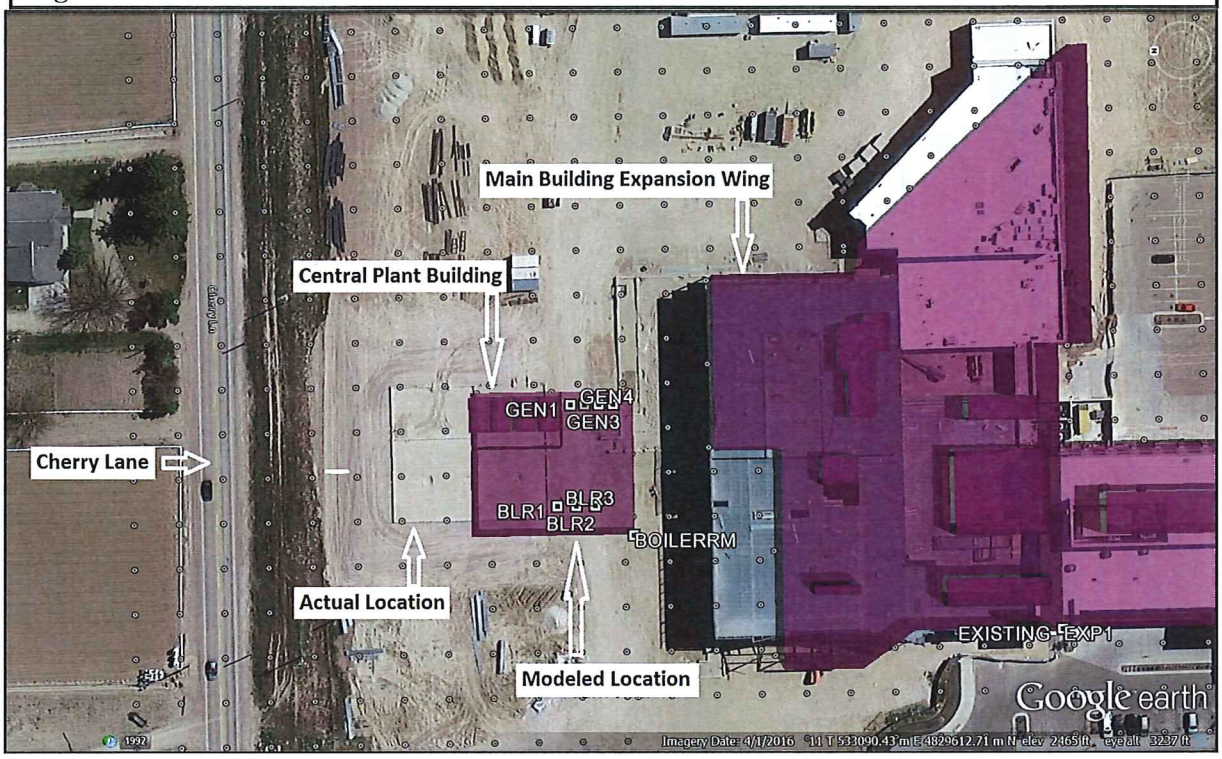


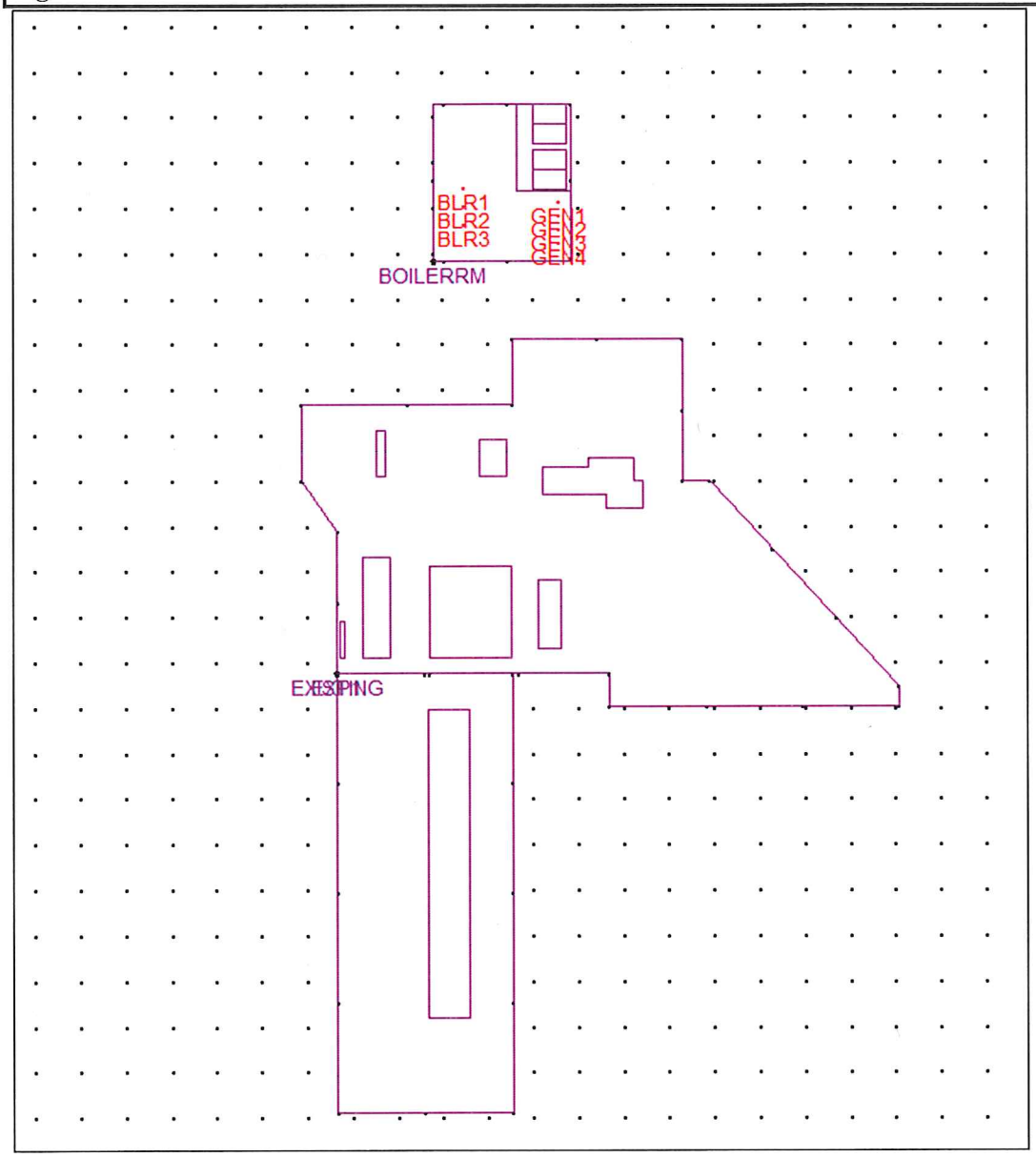
Figure 2. ST. LUKE'S NAMPA MEDICAL CENTER DETAIL SHOWING BPIP ISSUES



3.7 *Ambient Air Boundary*

The ambient air boundary used for this project was established immediately exterior to all buildings on the SLNMC campus. Figure 3 below shows that discrete receptors were placed along the perimeter of the structure and in a grid exterior to the buildings. DEQ review concluded that the ambient air boundary employed in the final air impact analyses precluded public access based on the methods described in the modeling report according to the criteria described in DEQ's *Modeling Guideline*[2]. CH2M appropriately addressed air pollutant impacts to areas considered to be ambient air.

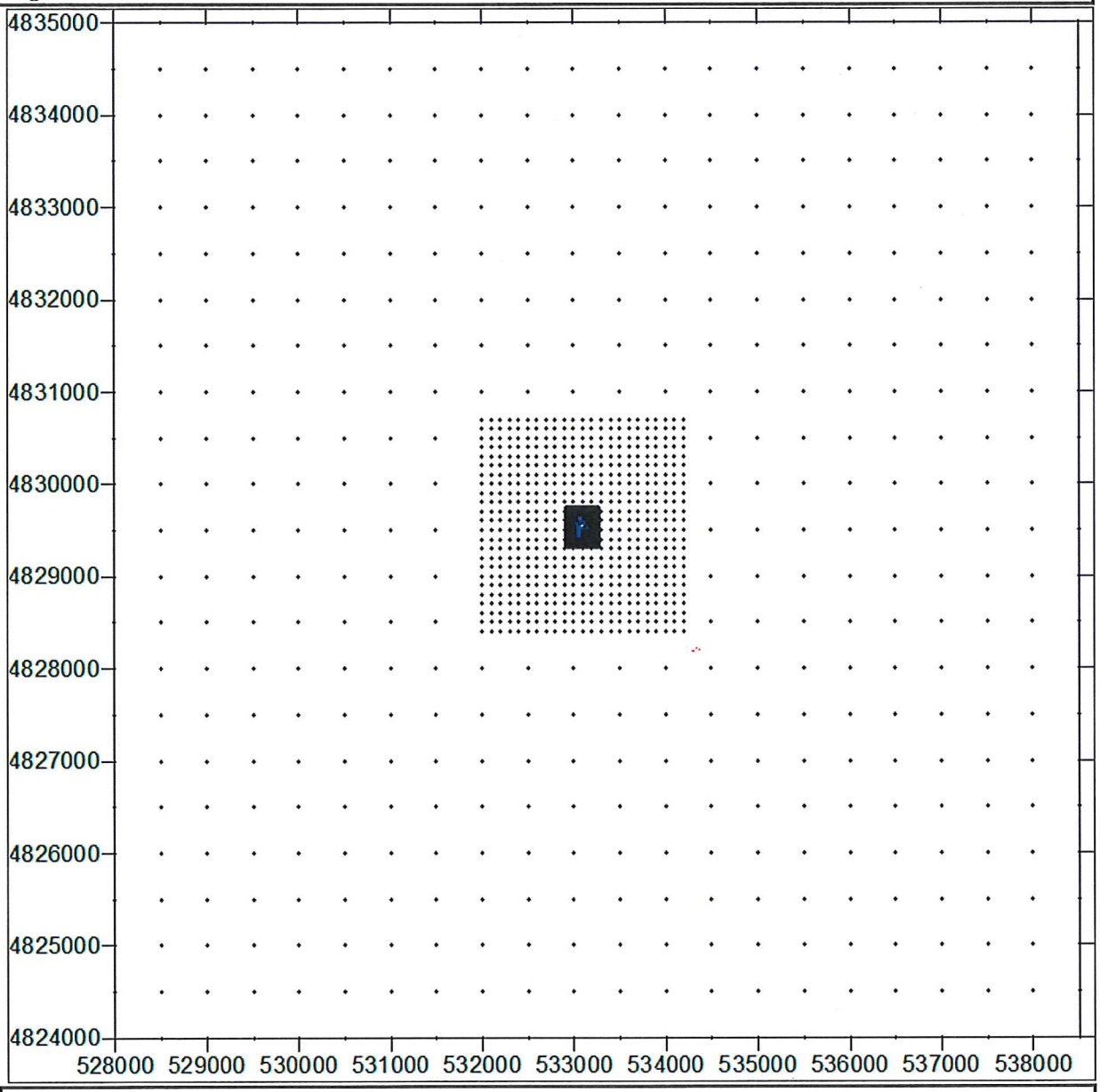
Figure 3. ST. LUKE'S MODEL SETUP AND INITIAL SET OF RECEPTORS



3.8 Receptor Network

Table 3 describes the receptor network used in the submitted modeling analyses. The receptor grids used in the model provided good resolution of the maximum design concentrations for the project and provided extensive coverage. The full receptor grid was used for SIL, NAAQS, and TAPs ambient air impact analyses. DEQ determined that the receptor network was effective in reasonably assuring compliance with applicable air quality standards at all ambient air locations. The complete extent of the receptor grid is depicted below in Figure 4.

Figure 4. FULL RECEPTOR GRID



UTM Coordinates in NAD83 Datum, Facility is located in Zone 11, Coordinates are in units of meters

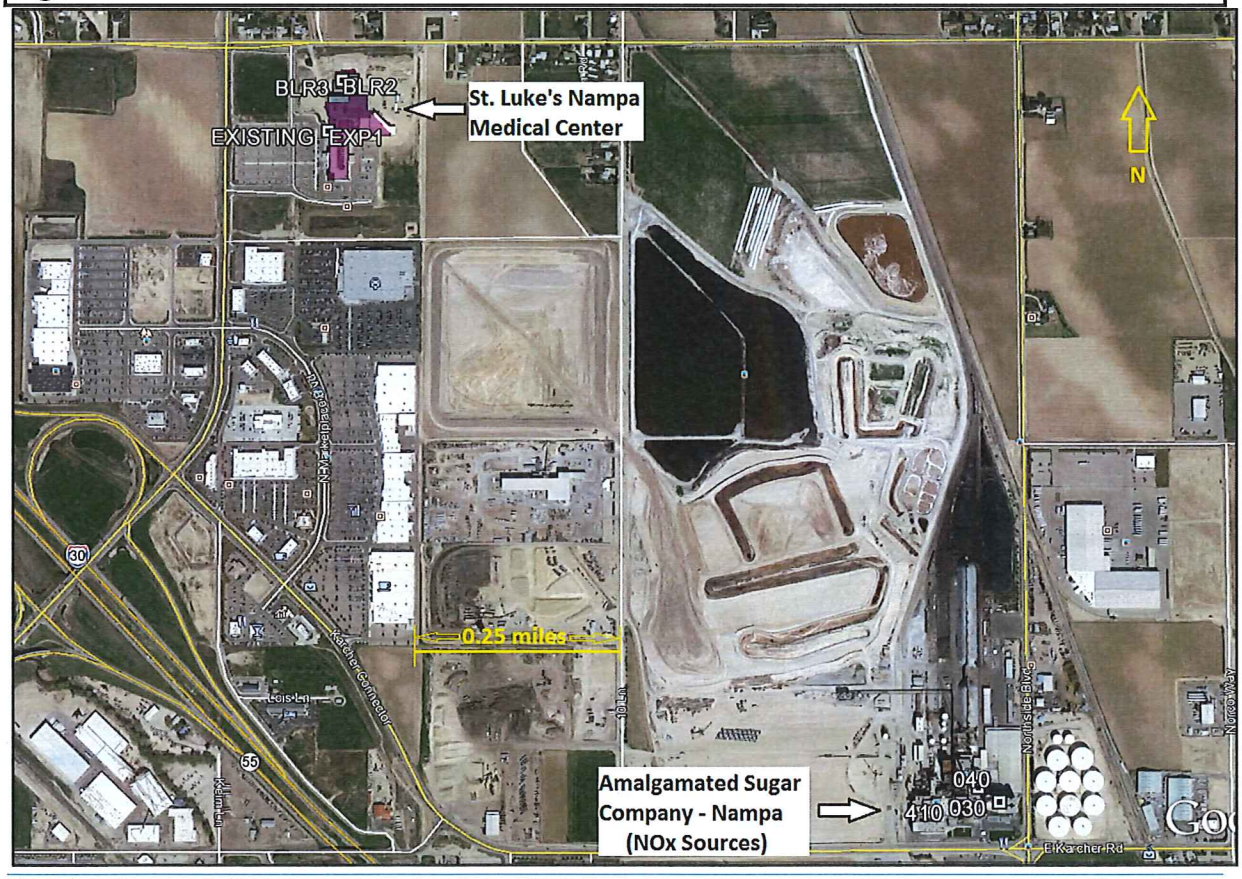
3.9 Emission Rates

Review and approval of estimated emissions is the responsibility of the DEQ permit writer, and the representativeness and accuracy of emissions estimates is not addressed in this modeling review memorandum. DEQ air impact analyses review included verification that the potential emissions rates provided in the emissions inventory were properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used for the SLNMC facility in the dispersion modeling analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emissions inventory. All modeled criteria air pollutant and TAP emissions rates must be equal to or greater than the facility's potential emissions calculated in the PTC emissions inventory or proposed permit allowable emissions rates.

DEQ requested that the SLNMC project model a nearby source in any cumulative NAAQS ambient impact analyses conducted. Impacts for 1-hour average NO_2 and annual NO_2 exceeded the significant impact levels, thereby requiring a cumulative NAAQS impact analysis. All other pollutant emissions rates for the project, as described in the submitted May 13, 2016 incompleteness response, were exempted from modeling requirements based on the project's requested PTE being below the BRC emission rates. This memorandum only presents the information required to be included in the final cumulative NAAQS analyses. On February 3, 2016, DEQ provided CH2M the emissions inventory information for the nearby source with the modeling protocol approval letter. The Amalgamated Sugar Company (TASCO) facility was the only facility identified by DEQ as a nearby co-contributing source for this project. The TASCO emissions inventory was obtained from the 2014 year National Emissions Inventory (NEI) submitted by each facility subject to the reporting requirement. The inventory established emissions on a quarterly basis during the calendar year to account for variations in activity levels for each emissions unit. This inventory is intended to reflect actual emissions for the inventory period rather than the potential to emit. Modeling of actual emissions for co-contributing sources is appropriate for these analyses. Figure 5 below shows the location of the SLNMC and TASCO facilities in relation to one another.

Figure 5. ST. LUKE'S AND THE AMALGAMATED SUGAR COMPANY PROXIMITY



3.9.1 Criteria Pollutant Emissions Rates for Significant Impact Level and Cumulative Analyses

A significant impact level (SIL) analysis was submitted as part of the air quality NAAQS/TAPs compliance demonstration. Cumulative NAAQS analyses were required to be conducted for NOx emissions to demonstrate compliance with the 1-hour and annual average NO_2 NAAQS. The emissions rates modeled for the SIL analyses for the SLNMC sources were identical to those modeled for the cumulative NAAQS ambient impact analyses.

Table 6 lists criteria pollutant continuous (24 hours per day) emissions rates used to evaluate NAAQS compliance for standards with averaging periods of 24 hours or less. Table 7 lists criteria pollutant continuous (8,760 hours/year) emissions rates used to evaluate NAAQS compliance for standards with an annual averaging period. These modeled rates must be equal or greater than permit allowable facility-wide emissions for the listed averaging period.

Table 6. ST. LUKE'S SHORT-TERM CRITERIA POLLUTANT EMISSIONS RATES

Emissions Point	Description	NO_x[a] (lb/hr)[b]
BLR1	Hurst boiler #1–dual fuel	1.764
BLR2	Hurst boiler #2–dual fuel	0.470
BLR3	Hurst boiler #3–dual fuel	0.470

a. Nitrogen oxides.
b. Pounds per hour.

Table 7. ST. LUKE'S ANNUAL CRITERIA POLLUTANT EMISSIONS RATES

Emissions Point	Description	NO_x[a] (lb/hr)[b]
BLR1	Hurst dual fuel boiler #1	0.477
BLR2	Hurst dual fuel boiler #2	0.477
BLR3	Hurst dual fuel boiler #3	0.477
GEN1	Emergency generator engine #1	0.189
GEN2	Emergency generator engine #2	0.189
GEN3	Emergency generator engine #3	0.189
GEN4	Emergency generator engine #4	0.189

a. Nitrogen oxides.
b. Pounds per hour.

3.9.2 Criteria Pollutant Emissions Rates for Nearby Source – TASCO - Nampa

Table 8 lists the criteria pollutant continuous (24 hours per day) emissions rates for the nearby TASCO source used to evaluate NAAQS compliance for standards with averaging periods of 24 hours or less. Table 9 lists TASCO's criteria pollutant continuous (8,760 hours/year) emissions rates used to evaluate NAAQS compliance for standards with an annual averaging period except where noted.

CH2M developed the hourly modeled emission rates for TASCO from the 2014 NEI spreadsheet provided by DEQ's Emissions Inventory group to the DEQ modeling group. This inventory contained actual annual emissions rates for CO, total NOx, filterable PM_{10}, filterable $PM_{2.5}$, SO_2, and VOCs. Only the hourly and annual total NOx emissions rates are of concern for this SLNMRC project. Annual emissions in units of tons per year for each point or area source at the facility are documented in the 2014 NEI. Actual annual operating hours for each seasonal period and a seasonal activity percentage for each season (compared to the percentage total activity) allowed CH2M to estimate

hourly emission rates. AERMOD Operational Factors were applied to the Union Boiler, Lime Kiln A and B stack, and the Main Mill Kiln Carbonation Vent. The factors accounted for fall and winter season operations covering September through February at the listed emission rates. During March through August these sources were not modeled, as AERMOD assigned an emission rate of zero lb/hr for these sources. This approach is backed by TASCO's emissions inventory that accounts for seasonal operation of some sources. The combined stack for B&W Boilers 1 and 2, and the Riley Boiler was assumed to operate continuously at the listed emission rates.

Table 8. TASCO SHORT-TERM AVERAGE EMISSIONS RATES

Emissions Point	Description	NO_x[a] (lb/hr)[b]
30	B&W Boilers 1 &2, and Riley Boiler Combined Stack	339.11[c]
40	Union Boiler	4.06[d]
95	Lime Kilns A and B	6.03[d]
410	Main Mill Kiln Process Exhaust Carbonation Vent	19.81[d]

a. Nitrogen oxides.
b. Pounds per hour.
c. Source modeled continuously.
d. Source modeled at this emission rate during fall and winter seasons. Nonoperational (0.0 lb/hr of emissions) during spring and summer seasons.

Table 9. TASCO ANNUAL AVERAGEEMISSIONS RATES

Emissions Point	Description	NO_x[a] (lb/hr)[b]
030	B&W Boilers 1 &2, and Riley Boiler Combined Stack	219.74[c]
040	Union Boiler	2.58[d]
095	Lime Kilns A and B	2.37[d]
410	Main Mill Kiln Process Exhaust Carbonation Vent	7.79[d]

a. Nitrogen oxides.
b. Pounds per hour.
c. Source modeled continuously.
d. Source modeled at this emission rate during fall and winter seasons. Nonoperational (0.0 lb/hr of emissions) during spring and summer seasons.

3.9.3 Toxic Air Pollutant Emissions

The increase in emissions from the proposed project are required to demonstrate compliance with the toxic air pollutant (TAP) increments, with an ambient impact analyses required for any TAP having a requested potential emission rate that exceeds the screening emissions level (EL) specified by Idaho Air Rules Section 585 or 586. Review of the TAPs emissions inventory, and authority to request alterations to the inventory, is the responsibility of the permit writer/project manager.

This project modeled four TAPs with emission rates that exceeded the carcinogenic screening emission rate limits (ELs) specified in Section 586 of the Idaho *Air Rules*.

The hourly TAPs emission rates listed in Table 10 were modeled for 8,760 hours per year.

Table 10. TOXIC AIR POLLUTANT EMISSIONS RATES

Pollutant	Chemical Abstract Service Number	Emissions Source		
		BLR1 Hurst Boiler 1	BLR2 Hurst Boiler 2	BLR3 Hurst Boiler 3
Arsenic (lb/hr)[a]	7440-38-2	2.79E-06	2.79E-06	2.79E-06
Cadmium (lb/hr)	7440-43-9	1.54E-05	1.54E-05	1.54E-05
Formaldehyde (lb/hr)	50-00-0	1.0E-03	1.0E-03	1.0E-03
Nickel (lb/hr)	7440-02-0	2.93E-05	2.93E-05	2.93E-05

a. Pounds per hour.

3.10 Emission Release Parameters

Table 11 lists emissions release parameters for modeled sources for the SLNMC facility. Table 12 lists the release parameters for modeled sources for the co-contributing TASCO facility.

Table 11. ST. LUKE'S POINT SOURCE EMISSIONS RELEASE PARAMETERS

Release Point	Description	UTM[a] Coordinates, Zone 11		Stack Base Elevation (m)	Stack Height (m)	Modeled Diameter (m)	Stack Gas Temp (K)[c]	Stack Flow Velocity (m/s)[d]	Stack Release Type
		Easting (m)[b]	Northing (m)						
BLR1	St Lukes Boiler 1 - Hurst Dual Fuel	533,064.57	4,829,624.18	750.63	15.24	0.508	435.37	10.67	Rain capped
BLR2	St Lukes Boiler 2 - Hurst Dual Fuel	533,064.57	4,829,620.18	750.63	15.24	0.508	435.37	10.67	Rain capped
BLR3	St Lukes Boiler 3 - Hurst Dual Fuel	533,064.57	4,829,616.17	750.63	15.24	0.508	435.37	10.67	Rain capped
GEN1	Emergency generator engine #1	533,085.74	4,829,621.17	750.63	13.72	0.254	763	50.00	Vertical and uninterrupted
GEN2	Emergency generator engine #2	533,085.74	4,829,618.18	750.63	13.72	0.254	763	50.00	Vertical and uninterrupted
GEN3	Emergency generator engine #3	533,085.74	4,829,615.17	750.63	13.72	0.254	763	50.00	Vertical and uninterrupted
GEN4	Emergency generator engine #4	533,085.74	4,829,612.17	750.63	13.72	0.254	763	50.00	Vertical and uninterrupted

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters per second.

DEQ's permitting policies and guidance require that each permit application have stand-alone documentation to support the appropriateness of release parameters used in the air impact analyses. The SLNMC modeling report submitted to DEQ provided justification and documentation of assumptions and data supporting key release parameters used to model these point sources.

The SLNMC emission sources are associated with a proposed facility, with project construction underway as of the date of this memorandum. Design data were used to support values used for release parameters rather specific source measurement-based data. The support documentation justifying the release parameters was reviewed by DEQ modeling staff and was found to be adequate.

Boilers

The three Hurst dual fuel boilers will be identical units, each rated at 14.25 million British thermal units per hour (MMBtu/hr) heat input with natural gas and distillate fuel oil burners. The manufacturing company for the boilers provided release parameter documentation for these boilers. Each boiler will be equipped with an economizer, which will lower the exhaust temperature and the exhaust volumetric flow rate (and thus exit velocity) as a result of recovering heat from the exhaust stream. DEQ's February 3, 2016, modeling protocol approval letter requested CH2M to calculate each stacks volumetric flow rate in units of actual cubic feet per minute and verify that calculations are representative of stack conditions post-economizer and not pre-economizer. In Section 4.1.1 of the permit application's modeling report, CH2M provided the following statement:

"A Hurst boiler manufacture was contacted on March 18, 2016 and verified that the flue gas flow

rate of 2,840 scfm is for post economizer. Exit exhaust flowrate conversions were made form 2840 scfm to 4583 acfm."

DEQ determined justification and documentation of the Hurst boiler was adequate.

Emergency Generator Engines

DEQ requested additional justification of the release parameters for the emergency generator engines in the April 20, 2016, incompleteness determination letter. DEQ's request and CH2M's response are presented below.

- Considering the emergency engines will likely be placed at ground level and each engine will employ a muffler and additional stack height to extend the final release height of the stacks 45 feet above grade, the exhaust temperature should be lower than the manufacturer's specification sheet value of 913.7 degrees Fahrenheit because the exhaust will experience a certain amount of cooling. The stack exit velocity should represent the conditions at 75% load and the appropriate exit temperature or a value that has been determined to be conservative.

  Based upon pressure loss values supplied by Western States Caterpillar, pressure loss and temperature loss were calculated to be negligible for the proposed stack conditions as demonstrated in Appendix B (Egen Convective Loss – calculation). A pressure loss of 0.2% was calculated, yielding negligible temperature loss using the ideal gas law. Given the negligible losses, the emergency engine stack temperatures remain unchanged. Therefore, the exit stack temperature proposed at 75% load is 913.7 F or 763 K.

  Based on conversations with Western States Caterpillar, measurements were assumed to have been taken at the exhaust manifold and do not accurately reflect conditions after a muffler and cooling in the stack. Therefore, a default stack exit velocity of 50 m/s was used for each of the four emergency generators.

Caterpillar specification sheet support documentation was provided for the emergency generator exhaust flow rate and exit temperature for the four 1,218 brake horsepower (bhp) diesel engines operating at 75% load capacity. The exhaust stacks will be built with a release height extended to 45 feet above grade to create a release height that is 5 feet above the roofline of the Central Plant structure (model ID BOILERRM). CH2M's May 13, 2016 response letter indicated that "…pressure and temperature loss were calculated to be negligible for the proposed stack conditions as demonstrated in Appendix B (Egen Convective Loss – calculation). The following calculation found in Attachment B of the final application presented additional documentation to support the 913.7 degree Fahrenheit (°F) exit temperature assumption. It is not entirely clear whether the convective loss calculation accounts for the pressure and heat loss through a muffler system described in the second half of CH2M's response listed above.

Emergency Generators – Convective Loss Calculation

$$\frac{45}{100} x\ 3\ in\ H2O = 1.35\ in\ H2O\ pressure\ loss\ in\ stack$$

$$1.35\ in\ H2O\ x \frac{1}{27.68} \frac{PSI}{in\ H2O} = .049\ PSI\ loss\ in\ stack$$

$$Atmospheric\ Pressure\ at\ 2500\ ft = 13.4\ PSI$$

$$Guage\ Pressure = 31.2\ in\ Hg\ x \frac{1\ PSI}{2.036\ in\ Hg} = 15.32\ PSI$$

$$Absolute\ Pressure\ at\ Exhaust = 15.32\ PSI + 13.4\ PSI = 28.72\ PSI$$

$$Absolute\ Pressure\ at\ Top\ of\ Stack = 28.72\ PSI - 0.49\ PSI = 28.67\ PSI$$

$$Percent\ Difference = \frac{28.72\ PSI - 28.67\ PSI}{28.72\ PSI} x\ 100 = 0.2\%$$

Reference:

Pressure loss provided by Western States Caterpillar, Norman Ricks –Mechanical Engineer (May 2, 2016)

Appendix B of the application also contains a volumetric flow rate conversion calculation based on the ideal gas law using flow rate and temperature values obtained from Caterpillar specification sheet support documentation under the "General Performance Data" section. Using the ideal gas law, the specification sheet's "Engine Outlet Temperature" of 913.8 °F, and "Engine Outlet Wet Exh Gas Vol Flow Rate" in units of "CFM" (regarded by CH2M as standard cubic feet per minute) yielded a flow rate of 14,257 ACFM. With a 10-inch diameter stack, this flow provides a 133 meter/ second (m/s) (equal to 436 feet/ second) exit velocity. DEQ considers this velocity to be suspiciously high. To resolve the question, DEQ approved an approach proposed by CH2M to reduce the exhaust flow velocity to 50 m/s. If the 5,042 CFM value listed in the Caterpillar specification sheet is considered as "ACFM," then the exit velocity from a 10-inch diameter stack is 47 m/s. This supports use of the 50 m/s velocity used in the final submitted analyses. The modeled release temperature was not reduced.

The emergency generator engines for this project were only required to be modeled in the annual average NO_2 NAAQS ambient air impact analyses. With a 100 hour per year operating limitation the generator engines reflect operation at 1.1% of the calendar year, and impacts are minimal for these sources. The effect of variations in release parameters for the generator engines will be minimized and DEQ concludes that the parameters used in the modeling analyses were adequately supported and appropriate for this project.

Cooling Towers

Review of the cooling tower release parameters is unnecessary given the project was exempted from PM_{10} and $PM_{2.5}$ ambient air impact analyses based on BRC modeling exemptions.

Co-contributing TASCO Facility

The neighboring TASCO facility was identified as a potential co-contributing source for inclusion in any applicable NAAQS analyses triggered by the proposed SLNMC project. Release parameters documented in the 2014 NEI were provided to CH2M for this project's ambient air impact analyses. DEQ did not further review the release parameters for the TASCO. DEQ determined the quality assurance and quality control measures of the NEI process provided adequate justification and documentation of release parameters. The locations of the modeled TASCO emissions sources, as

provided in the NEI data, appeared reasonably accurate.

Table 12. AMALGAMATED SUGAR COMPANY POINT SOURCE EMISSIONS RELEASE PARAMETERS									
Release Point	Description	UTM[a] Coordinates, Zone 11		Stack Base Elevation (m)	Stack Height (m)	Modeled Diameter (m)	Stack Gas Temp (K)[c]	Stack Flow Velocity (m/s)[d]	Stack Release Type
		Easting (m)[b]	Northing (m)						
30	TASCO - B&W Boilers 1 &2, and Riley Boiler Combined Stack	534,374	4,828,205	753.53	74.68	2.13	449.82	16.00	Vertical and uninterrupted
40	TASCO - Union Boiler	534,345.7	4,828,220.4	753.53	20.12	1.22	435.93	7.65	Vertical and uninterrupted
95	TASCO - Lime Kilns A and B	534,311.1	4,828,192.5	753.59	24.99	0.91	352.59	10.06	Vertical and uninterrupted
410	TASCO Main Mill Kiln Process Exhaust Carbonation Vent	534,299.0	4,828,185.7	753.62	32.92	1.01	355.37	6.71	Vertical and uninterrupted

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters per second.

4.0 Results for Air Impact Analyses

CH2M elected to demonstrate compliance for annual average NO_2 significant impacts level analyses (SIL) and NAAQS analyses using the Tier 1 NO_2 method. This is the most conservative method and DEQ approval is not required. The Tier 2 Ambient Ratio Method 2 (Tier 2 ARM2) method was used for the 1-hour average NO_2 SIL and NAAQS analyses, using the conservative default value of 0.5 for the minimum ambient ratio (ARM_MIN) value. DEQ approval was provided for the ARM2 method based on the Tier 1 project impact and the conservative default ARM2_MIN value applied in the model.

4.1 Results for Significant Impact Analyses

Table 13 provides results for the and annual and 1-hour NO_2 significant impacts level analyses (SIL) analyses. Cumulative 1-hour and annual NO_2 NAAQS impact analyses were needed for all pollutants modeled in the SIL analyses because the applicable SILs were exceeded.

Table 13. RESULTS FOR SIGNIFICANT IMPACT ANALYSES				
Pollutant	Averaging Period	Modeled Design Value Concentration ($\mu g/m^3$)[a]	SIL[b] ($\mu g/m^3$)	Percent of SIL
NO_2[c]	1-hour	127.0[d]	7.5	1,693%
	Annual	8.29[e]	1.0	829%

a. Micrograms per cubic meter.
b. Significant impact level.
c. Nitrogen dioxide.
d. Modeled design value is the maximum 5-year mean value of maximum 1st highest daily 1-hour maximum impacts.
e. Modeled design value is the maximum annual impact of the individual years of a 5-year meteorological dataset.

4.2 Results for Cumulative NAAQS Impact Analyses

CH2M presented cumulative impact analyses for the 1-hour and annual NO_2 NAAQS. The results for the cumulative impact analyses are listed in Table 14. Ambient impacts for the facility and the nearby TASCO facility, when combined with approved ambient backgrounds were below the allowable annual and 1-hour NO_2 NAAQS.

Table 14. RESULTS FOR CUMULATIVE IMPACT ANALYSES

Pollutant	Averaging Period	Modeled Design Value Concentration ($\mu g/m^3$)[a]	Background Concentration ($\mu g/m^3$)	Total Ambient Impact ($\mu g/m^3$)	NAAQS[b] ($\mu g/m^3$)	Percent of NAAQS
NO_2[c]	1-hour	181.6[d]	Included in design value	181.6	188	97%
	Annual	8.9[e]	10.9[f]	19.8	100	20%

a. Micrograms per cubic meter.
b. National ambient air quality standards.
c. Nitrogen dioxide.
d. Modeled design value is the maximum 5-year mean of 8th highest 24-hour values from each year of a 5-year meteorological dataset.
e. Modeled design value is the maximum of annual values from each individual year of 5 years of data.
f. NW AIRQUEST background value.

4.3 Results for Toxic Air Pollutant Impact Analyses

Table 15 presents results for TAPs modeling. The impacts listed below are attributed to the facility-wide emissions. All design impacts are the maximum impacts. Annual average carcinogenic TAP impacts used the maximum impact from five individual years of meteorological data. All TAP impacts were below the applicable increments.

Table 15. RESULTS FOR TOXIC AIR POLLUTANT ANALYSES

Pollutant	CAS[a] Number	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)[b]	AACC[c] ($\mu g/m^3$)	Percent of Increment
Arsenic	7440-38-2	Annual	5E-05	2.3E-04	22%
Cadmium	7440-43-9	Annual	2.6E-04	5.6E-04	46%
Formaldehyde	50-00-0	Annual	1.8E-02	7.7E-02	23%
Nickel	7440-02-0	Annual	4.9E-04	4.2E-03	12%

a. Chemical Abstract Service
b. Micrograms per cubic meter.
c. Ambient Concentration for Carcinogens (Toxic Air Pollutant allowable increments listed in Idaho Air Rules Section 586).

4.4 Verification Analyses

DEQ conducted an analysis to verify that 1-hour average NO_2 NAAQS compliance was assured after noting that the modeled structure for the expansion building outline did not match the outline of recent updates to the Google earth® imagery software. An additional tier section matching the perimeter of the portion of the main building's expansion wing directly adjacent to the Central Plant (Modeling BPIP ID "BOILERRM") was added with a tier height above grade matching the surrounding structure. See Figure 2 above to note the difference between the footprint already constructed and the modeled footprint. DEQ did not alter the eastern section of the expansion building that did not match the overhead imagery. DEQ added the most critical part of the structure for building downwash concerns

as described above. Figure 6 below shows the section of the building that DEQ added to verify that 1-hour NO_2 NAAQS compliance was assured for this project.

The maximum design value ambient impact was not altered with the inclusion of the missing building section. DEQ concludes that NAAQS and TAPs compliance has been adequately demonstrated with the submitted ambient air impact analyses and DEQ's verification analyses. The design concentration plus ambient background for the verification run is listed in Table 16.

Figure 6. ST. LUKE'S NAMPA DEQ FILL-IN FOR MISSING SECTION OF STRUCTURE

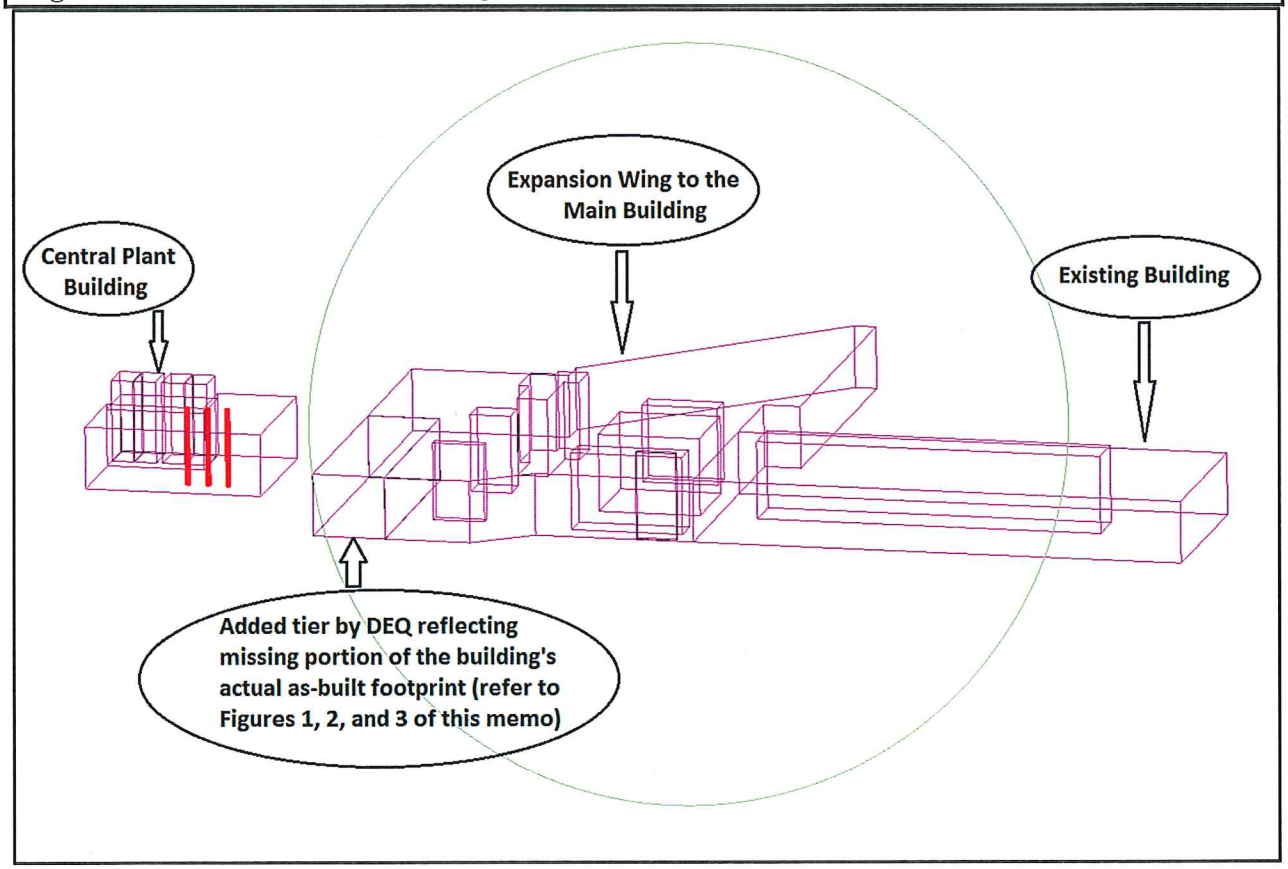


Table 16. RESULTS FOR DEQ VERIFICATION ANALYSES

Pollutant	Averaging Period	Modeled Design Value Concentration ($\mu g/m^3$)[a]	Background Concentration ($\mu g/m^3$)	Total Ambient Impact ($\mu g/m^3$)	NAAQS[b] ($\mu g/m^3$)	Percent of NAAQS
NO_2[c]	1-hour	181.6[d]	Included in design value	181.6	188	97%

a. Micrograms per cubic meter.
b. National ambient air quality standards.
c. Nitrogen dioxide.
d. Modeled design value is the maximum 5-year mean of 8th highest 24-hour values from each year of a 5-year meteorological dataset.

5.0 Conclusions

The ambient air impact analyses demonstrated to DEQ's satisfaction that emissions from the SLNMC facility will not cause or significantly contribute to a violation of any NAAQS and will not exceed allowable TAP increments.

References

1. *Policy on NAAQS Compliance Demonstration Requirements of IDAPA 58.01.01.203.02 and 01.403.02.* Idaho Department of Environmental Quality Policy Memorandum. Tiffany Floyd, Administrator, Air Quality Division, June 10, 2014.

2. *State of Idaho Guideline for Performing Air Quality Impact Analyses.* Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *Ambient Ratio Method Version 2(ARM2) for use with AERMOD for1-hr NO_2 Modeling Development and Evaluation Report,* Prepared for American Petroleum Institute, 1220 L Street NW, Washington, DC 20005, by M. Podrez, RTP Environmental Associates, Inc., 2031 Broadway, Suite 2, Boulder, Colorado 80302, September 20, 2013.

4. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard,* R. Chris Owen and Roger Brode, Environmental Protection Agency, Office of Air Quality Planning and Standards, September 30, 2014.

Attachment A

DEQ Communication with CH2M
Regarding 1-hour NO_2 Ambient Background
Dataset Development

Contents of an Email Communication from DEQ to CH2M concerning the development of an alternative 1-hour NO_2 Ambient Background Dataset for Use in Project Ambient Impact Analyses

Date/Time: March 2, 2016 9:08 am MST

From: Darrin Mehr <Darrin.Mehr@deq.idaho.gov>

To: 'Rick.McCormick@CH2M.com'; 'Monica.Wright@ch2m.com'

Cc: Kevin Schilling <Kevin.Schilling@deq.idaho.gov>; Estee.Lafrenz@ch2m.com; John.Frohning@CH2M.com

Subject: TRIM: RE: St. Luke-Nampa Protocol addendum and ON Semiconductor/Aptina Protocol Addendum - Request for formal DEQ approval of alternative 1-hour NO2 backgrounds

Attachments: File 1: Near Road NO2 from the Conventional NOx Box.txt

File 2: Near Road Photolytic NO2.txt

Hello Rick and Monica,

DEQ has reviewed the December 11, 2015, modeling protocol addendum submittal for establishing alternative ambient background concentrations for the 1-hour nitrogen dioxide (NO_2) NAAQS demonstration. The proposed method would establish NO_2 backgrounds that varied seasonally and diurnally. The proposed methods are intended to be applied to the St. Luke's Nampa PTC project and the Aptina/ON Semiconductor Nampa FEC permit renewal project.

DEQ has reviewed the memorandum and calculation spreadsheet for the 2012-2014 Meridian, Idaho near-road NO_2 monitoring site. Based on the information presented in the data and calculation spreadsheet supplied with the addendum, DEQ concludes the seasonal approach offered by the EPA guidance[1] is not supported and DEQ does not approve of the use of the seasonal hourly background values as submitted.

The monitoring data represented in the 2012, 2013, and 2014 individual year statistical analyses was extremely limited for winter 2012 and 2014 seasonal periods. Hourly NO_2 data was entirely absent from the analyses for January and February 2012 and 2014, leaving December data alone to establish the winter season background for those years. The monitoring data used in the submittal appeared to be from the primary NO_2 monitor, identified as the "POC 1" monitor at the Meridian Near-Road site. DEQ is concerned that the proposed method of establishing the 3rd high ranked monitoring value from the limited dataset for seasonal periods of approximately 1/3 data capture may not provide the appropriate winter season individual year design value. Spring season design values are also a concern as less than 75% of monitoring days in the season were represented in the background for 2012 and 2014. Even though proposed background analyses calculated each overall seasonal design value as the maximum of three years of the season's 3rd-ranked monitored concentrations, this approach may not be adequately conservative for NAAQS compliance assurances. Although seasonality is discussed as an option in EPA guidance[1], such guidance assume complete site-specific data, modeling of all nearby sources, and modeling of all NO_2 sources at the permitted facility. The 3rd rank value (representing the 98th percentile) was not the appropriate rank of the design value for 5 of the 12 seasons considered, based on the amount of data within

[1] Tyler Fox, "*Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard*". U.S. Environmental Protection Agency, Research Triangle Park, NC, March 1, 2011.

each of the seasons.

Given the ambient monitor is not an on-site monitor, the level of detail available in establishing hourly NO_x emissions for modeling the co-contributing Amalgamated Sugar Company's facility's emissions for compliance with a 1-hour ambient standard, and consideration that NO_x emissions from a number of emergency generators at both facility sites will not be modeled as allowed by DEQ policy, DEQ believes the proposed method should be replaced by the use of an annualized diurnal NO_2 background dataset that is based on the 98th percentile value for each hour within the 3-year period of the monitoring data used in the proposed submittal. This follows the EPA guidance and removes the concern that any of the seasonal values are not accurate or conservative. Table 1 of 40 CFR 50, Appendix S—listed below--shows the appropriate ranking for 98th percentile values based upon an individual year of data.

Table 1 – 98th Percentile Rankings

Annual number of days with valid data for year "y" (cn_y)	*$P_{0.98,y}$ is the nth maximum value of the year, where n is the listed number*
1-50	1
51-100	2
101-150	3
151-200	4
201-250	5
251-300	6
301-350	7
351-366	8

[75 FR 6532, Feb. 9, 2010]

For the purposes of creating a modeling demonstration ambient background used in NAAQS analyses, DEQ is entertaining options for data substitution for missing primary monitor data that are not generally used in establishing primary standard design values that are used to establish compliance with the primary 1-hour NO_2 NAAQS. In other words, where extensive gaps in data coverage exist, in order to gain a more robust representation of the NO_2 background at the monitor site, CH2M may use the POC 2 secondary monitor data to fill in missing primary POC 1 data. The annualized diurnal NO_2 background should then be based on the average of the diurnal design values for each of the 3 individual years which follows EPA's 2011 guidance memorandum.

DEQ does not approve the use of the seasonal diurnal backgrounds as submitted. DEQ will consider applying the seasonal diurnal 1-hour NO_2 ambient background method if a more complete dataset is used in a revised submittal. CH2M may apply this method if the collocated monitor—designated POC 2—is used to fill in the POC 1 monitoring data gaps. However, the Meridian Near Road site was not operational until April 1, 2012, leaving three entire months missing from the 2012 data record. The Winter 2012 and Spring 2012 seasons are affected by this limitation. DEQ believes that a better alternative to just using POC 2 monitor data for data fill in the current data period, would be to shift the seasonal data record from the current period of April 1, 2012, through December 31, 2014, to a period covering June 1, 2012 through May 31, 2015. DEQ modeling staff have obtained a raw data set from DEQ monitoring staff that contains the additional 5 month period. The 2015 data

has not undergone final validation but it has received initial validation and it is expected to be accepted at this time. This provides the best dataset for a complete 3 year period to produce accurate representative seasonal diurnal monitoring, based on POC 1 data as the primary data and POC 2 data for filling in POC 1 gaps in valid data. An added advantage is that the winter seasons are comprised of consecutive 3 month periods instead of the initial two months of the year and the final month of the year.

Table 2: Summary of Options

	Option for Alternative 1-hour average NO_2 Backgrounds	Comments
1	Annual diurnal 98th percentile NO_2 background	• April 1, 2012 – December 31, 2014 dataset • Use only primary POC 1 monitor data. • The design value for each hour should be based on the 98th percentile value of all 3 years as a combined record for each hour of day.
2	Modified annual diurnal 98th percentile NO_2 background	• April 1, 2012 – December 31, 2014 dataset • Primary POC 1 monitor data • Secondary POC 2 monitor data fill for missing primary POC 1 monitor. • Design value for each hour of day calculated as the average of 3 individual years based on 98th percentile value.
3	Seasonal diurnal 98th percentile NO_2 background	• April 1, 2014 – December 2014 dataset • Dataset appended with January 1, 2015 – May 31, 2015 non-finalized monitoring data for the same monitor site. • POC 1 primary monitoring data first with POC 2 secondary monitoring data used for data fill if available. • Hourly seasonal design concentrations are established for 3 years of data for each season • 3 year period begins with the Summer 2012 season and ends with the Spring 2015 season

Please find the raw data files for the POC 1 and POC 2 Meridian Near Road monitor site attached. The relevant 2015 year data for each monitor can be extracted from these files if CH2M .
Please contact me if you have any questions or comments on this issue.

Best regards,

Darrin

Darrin Mehr
Air Quality Analyst
Stationary Source Modeling
Monitoring, Modeling, and Emissions Inventory, Air Program
State of Idaho Department of Environmental Quality
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APPENDIX D – PROCESSING FEE

PTC Fee Calculation

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**St. Luke's Nampa Medical Center**
Address:	**16850 MIDLAND AVENUE**
City:	**NAMPA**
State:	**ID**
Zip Code:	**83687**
Facility Contact:	**Russ Harbaugh**
Title:	**Director of Operations Building Services**
AIRS No.:	**027-00152**

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	9.6	0	9.6
SO_2	0.3	0	0.3
CO	7.2	0	7.2
PM10	1.0	0	1.0
VOC	4.7	0	4.7
TAPS/HAPS	0.4	0	0.4
Total:	**23.1**	0	**23.1**
Fee Due	**$ 5,000.00**		