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DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE A Q PROGRAM

Permit # P-2013.0057
Project # 61299
Facility ID # 065-00011
Regional Office IFRO
Logged: [✓]

BYU – IDAHO
CENTRAL ENERGY FACILITY

PRE – PERMIT CONSTRUCTION APPROVAL APPLICATION

For

IDAHO DEPARTMENT OF ENVIRONMENTAL QUALITY

November 25, 2013

BYU IDAHO | Facilities Planning & Construction
283 University Operations Building · Rexburg, ID · 83460-8205 · Phone: (208) 496-2651

Pre-Permit Construction Approval Application

November 20, 2013

Idaho Department of Environmental Quality
Attn: Bill Rogers
1410 North Hilton
Boise, ID 83706-1255

RE: BRIGHAM YOUNG UNIVERSITY – IDAHO
PRE-PERMIT CONSTRUCTION APPROVAL APPLICATION

Dear Bill:

Brigham Young University – Idaho (BYUI) requests approval to begin construction prior to final approval of the permit to construct (PTC) to replace the existing coal boilers at the BYUI Heat Plant with natural gas-fired boilers and a combustion turbine/heat recovery steam generator. BYUI is eligible for pre-permit construction because it is not a major source under Prevention of Significant Deterioration regulations because:

- No netting of emissions to stay below major source levels is being relied upon,
- No use of offsets pursuant to IDAPA 58.01.01.206 is being used,
- No adverse impact on air quality related values of any Class 1 area will occur.

Documentation of this eligibility in contained in the PTC application attached to this letter. BYUI understands that approval to begin construction prior to PTC approval is subject to the following restriction:

- At our own risk,
- All emission limitations addressed in the application are enforceable,
- Emission units subject to the PTC may not be operated until the PTC is approved.

The PTC application for this project is attached, and it is the belief of BYUI that the application is complete. In addition, all public information notices have been published and all public informational meetings required by IDAPA 58.01.01.213 are being held within the required time periods in this regulation. Dispersion modeling has been performed according a modeling protocol submitted to and approved by IDEQ, and a report documenting the methods used and the results of the modeling are also being submitted with this request to begin construction prior to approval of the PTC.

If you have any questions or comments about this application, please do not hesitate to call me at (208) 496-2520, Al Oestmann (563) 260-0838, or Larry Veigel at (801) 322-0487.

Sincerely,

BRIGHAM YOUNG UNIVERSITY – IDAHO

Kyle Williams

Kyle Williams
Facility Manager Maintenance & Operations

cc: Mr. Larry Veigel, Heath Engineering Company (Salt Lake City, UT)
Mr. Al Oestmann, Trinity Consultants (West Burlington, IA)

Department of Environmental Quality
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

AQ-CH-P004

15- Day Pre-Permit Construction Approval Application Completeness Checklist

This checklist is designed to aid the applicant in submitting a complete pre-permit construction approval application. In addition to the items in this checklist, information requested by DEQ during review of the application should be provided in accordance with IDAPA 58.01.01.202.03, or the application may be denied.

I. Actions Needed Before Submitting Application

☒ Refer to the Rule. Read the Pre-Permit Construction requirements contained in IDAPA 58.01.01.213, Rules for the Control of Air Pollution in Idaho.

See Tab 1.

☒ Refer to DEQ's Pre-Permit Construction Approval Guidance Document. DEQ has developed a guidance document to aid applicants in submitting a complete pre-permit construction approval application. The guidance document is located on DEQ's website (go to http://www.deq.idaho.gov/air/permits_forms/permitting/ptc_prepermit_guidance.pdf

See Tab 2.

☒ Consult with DEQ Representatives. Schedule a pre-application meeting with DEQ to discuss application requirements before submitting the pre-permit construction approval application. Schedule the meeting by contacting the DEQ Air Permit Hotline at **877-5PERMIT**. The meeting can be in person or on the phone. Refer to IDAPA 58.01.01.213.01b.

See Tab 3.

☒ Schedule Informational Meeting. Schedule an informational meeting before submitting the pre-permit construction approval application for the purposes of satisfying IDAPA 58.01.01.213.02.a. The purpose for the informational meeting is to provide information about the proposed project to the general public. Refer to IDAPA 58.01.01.213.01.c.

See Tab 4.

☒ Submit Ambient Air Quality Modeling Protocol. It is required that an ambient air quality modeling protocol be submitted to DEQ at least two (2) weeks before the pre-permit construction approval application is submitted. Contact DEQ's Air Quality Hotline at **877-5PERMIT** for information about the protocol.

See Tab 5.

☒ Written DEQ Approved Protocol. Written DEQ approval of the modeling protocol must be received before the pre-permit construction approval application is submitted. Refer to IDAPA 58.01.01.213.01.c.

See Tab 6.

II. Application Content

Application content should be prepared using the checklist below. The checklist is based on the requirements contained in IDAPA 58.01.01.213 and DEQ's Pre-Permit Construction Approval Guidance Document.

☒ Pre-Permit Construction Eligibility and Proof of Eligibility. Pre-permit construction approval is not available for any new Prevention of Significant Deterioration (PSD) major source, any proposed PSD major modification, or any proposed major NSR project in a non-attainment area. Emissions netting and emissions offsets are not allowed to be used. A certified proof of pre-permit construction eligibility must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.

See Tab 7.

☒ Request to Construct Before Obtaining a Permit to Construct. A letter requesting the ability to construct before obtaining the required permit to construct must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.c.

See Tab 8.

☒ Apply for a Permit to Construct. Submit a Permit to Construct application using forms available on DEQ's website at http://www.deq.idaho.gov. Refer to IDAPA 58.01.01.213.01.a.

See Tab 9.

☒ Permit to Construct Application Fee. The permit to construct application fee of $1000 must be submitted at the time the original pre-permit construction approval application is submitted. Refer to IDAPA 58.01.01.224. If the pre-permit construction approval is denied and a new application is submitted, a new $1,000 application fee will be required to be submitted. The application fee is not transferable or refundable. The application fee can be paid by check, credit card or Electronic Funds Transfer (EFT). If you choose to pay by credit card or EFT, contact DEQ's Fiscal Office at (208) 373-0502 to complete the necessary paper work. If you choose to pay by check, enclose the check with your pre-permit construction approval application.

See Tab 10.

☒ Notice of Informational Meeting. Within 10 days after the submittal of the pre-permit construction approval application, an informational meeting must be held in at least one location in the region where the stationary source will be located. The information meeting must be made known by notice published at least 10 days before the informational meeting in a newspaper of general circulation in the county in which the stationary source will be located. A copy of this notice, as published, must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.02.a. Additional information regarding the informational meeting is included in DEQ's Pre-Permit Construction Approval Guidance Document. (go to http://www.deq.idaho.gov/air/permits_forms/permitting/ptc_prepermit_guidance.pdf)

See Tab 11.

☒ Process Description(s). The process or processes for which pre-permit construction approval is requested must be described in sufficient detail and clarity such that a member of the general public not familiar with air quality can clearly understand the proposed project. A process flow diagram is required for each process for which pre-permit construction approval is requested. Refer to IDAPA 58.01.01.213.01.c.

See Tab 12.

☒ Equipment List. All equipment that will be used for which pre-permit construction approval is requested must be described in detail. Such description includes, but is not limited to, manufacturer, model number or other descriptor, serial number, maximum process rate, proposed process rate, maximum heat input capacity, stack height, stack diameter, stack gas flowrate, stack gas temperature, etc. All equipment that will be used for which pre-permit construction approval is requested must be clearly labeled on the process flow diagram. Refer to IDAPA 58.01.01.213.01.c.

See Tab 13.

☒ Scaled Plot Plan. A scaled plot plan is required, with the location of each proposed process and the equipment that will be used in each process clearly labeled.

See Tab 14.

☒ Schedule for Construction. A schedule for construction is required, including proposed dates for commencement and for completion of the project. For phased projects, proposed dates are required for each phase of the project.

See Tab 15.

☒ Proposed Emissions Limits and Modeled Ambient Concentration for All Regulated Air Pollutants. All proposed emission limits and modeled ambient concentrations for all regulated air pollutants must demonstrate compliance with all applicable air quality rules and regulations. Regulated air pollutants include criteria air pollutants (PM_{10}, SO_x, NO_2, O_3, CO, lead), toxic air pollutants listed pursuant to IDAPA 58.01.01.585 and 586, and hazardous air pollutants listed pursuant to Section 112 of the 1990 Clean Air Act Amendments (go to http://www.epa.gov/ttn/atw/188polls.html). Describe in detail how the proposed emissions limits and modeled ambient concentrations demonstrate compliance with each applicable air quality rule and regulation. It is requested that emissions calculations, assumptions, and documentation be submitted with sufficient detail so DEQ can verify the validity of the emissions estimates. Refer to IDAPA 58.01.01.213.01.c.

See Tab 16.

☒ Restrictions on a Source's Potential to Emit. Any proposed restriction on a source's potential to emit such that permitted emissions will be either below major source levels or below a significant increase must be described in detail in the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.d.

See Tab 17.

☒ List all Applicable Air Quality Rules and Regulations. All applicable rules and regulations must be cited by the rule or regulation section/subpart that applies for each emissions unit. Refer to IDAPA 58.01.01.213.01.c.

See Tab 18.

☒ Certification of Pre-Permit Construction Approval Application. The pre-permit construction approval application must be signed by the Responsible Official and must contain a certification signed by the Responsible Official. The certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Refer to IDAPA 58.01.01.213.01.d and IDAPA 58.01.01.123.

See Tab 19.

☒ Submit the Pre-Construction Approval Application. Submit the pre-permit construction approval application and application fee to the following address:

Department of Environmental Quality
Air Quality Division
Stationary Source Program
1410 North Hilton
Boise, ID 83706-1255

TAB 1

source or facility may have, or are having, on the air quality in any area affected by the stationary source or facility; and (5-1-94)

e. Any other sampling and testing facilities as may be deemed reasonably necessary. (5-1-94)

02. Cancellation. The Department may cancel a permit to construct if the construction is not begun within two (2) years from the date of issuance, or if during the construction, work is suspended for one (1) year. (5-1-94)

03. Notification to The Department. Any owner or operator of a stationary source or facility subject to a permit to construct shall furnish the Department written notifications as follows: (5-1-94)

a. A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty (60) days or less than thirty (30) days prior to such date; and (5-1-94)

b. A notification of the actual date of initial start-up of the stationary source or facility within fifteen (15) days after such date. (5-1-94)

04. Performance Test. Within sixty (60) days after achieving the maximum production rate at which the stationary source or facility will be operated but not later than one hundred eighty (180) days after initial start-up of such stationary source or facility, the owner or operator of such stationary source or facility may be required to conduct a performance test in accordance with methods and under operating conditions approved by the Department and furnish the Department a written report of the results of such performance test. (5-1-94)

a. Such test shall be at the expense of the owner or operator. (5-1-94)

b. The Department may monitor such test and may also conduct performance tests. (5-1-94)

c. The owner or operator of a stationary source or facility shall provide the Department fifteen (15) days prior notice of the performance test to afford the Department the opportunity to have an observer present. (5-1-94)

212. OBLIGATION TO COMPLY.

01. Responsibility to Comply with All Requirements. Receiving a permit to construct shall not relieve any owner or operator of the responsibility to comply with all applicable local, state and federal statutes, rules and regulations. (5-1-94)

02. Relaxation of Standards or Restrictions. At such time that a particular facility or modification becomes a major facility or major modification solely by virtue of a relaxation in any enforceable emission standard or restriction on the operating rate, hours of operation or on the type or amount of material combusted, stored or processed, which was used to exempt the facility or modification from certain requirements for a permit to construct, the requirements for new major facilities or major modifications shall apply to the facility or modification as though construction had not yet commenced. (5-1-94)

213. PRE-PERMIT CONSTRUCTION.

This section describes how owners or operators may commence construction or modification of certain stationary sources before obtaining the required permit to construct. (3-23-98)

01. Pre-Permit Construction Eligibility. Pre-permit construction approval is available for non-major sources and non-major modifications and for new sources or modifications proposed in accordance with Subsection 213.01.d. Pre-permit construction is not available for any new source or modification that: uses emissions netting to stay below major source levels; uses optional offsets pursuant to Section 206; or would have an adverse impact on the air quality related values of any Class I area. Owners or operators may ask the Department for the ability to commence construction or modification of qualifying sources under Section 213 before receiving the required permit to construct. To obtain the Department's pre-permit construction approval, the owner or operator shall satisfy the following requirements: (4-5-00)

a. The owner or operator shall apply for a permit to construct in accordance with Subsections 202.01.a., 202.02, and 202.03 of this chapter. (3-23-98)

b. The owner or operator shall consult with Department representatives prior to submitting a pre-permit construction approval application. (3-23-98)

c. The owner or operator shall submit a pre-permit construction approval application which must contain, but not be limited to: a letter requesting the ability to construct before obtaining the required permit to construct, a copy of the notice referenced in Subsection 213.02; proof of eligibility; process description(s); equipment list(s); proposed emission limits and modeled ambient concentrations for all regulated air pollutants and toxic air pollutants, such that they demonstrate compliance with all applicable air quality rules and regulations. The models shall be conducted in accordance with Subsection 202.02 and with written Department approved protocol and submitted with sufficient detail so that modeling can be duplicated by the Department. (4-11-06)

d. Owners or operators seeking limitations on a source's potential to emit such that permitted emissions will be either below major source levels or below a significant increase must describe in detail in the pre-permit construction application the proposed restrictions and certify in accordance with Section 123 that they will comply with the restrictions, including any applicable monitoring and reporting requirements. (3-23-98)

02. Permit to Construct Procedures for Pre-Permit Construction. (3-23-98)

a. Within ten (10) days after the submittal of the pre-permit construction approval application, the owner or operator shall hold an informational meeting in at least one (1) location in the region in which the stationary source or facility is to be located. The informational meeting shall be made known by notice published at least ten (10) days before the meeting in a newspaper of general circulation in the county(ies) in which the stationary source or facility is to be located. A copy of such notice shall be included in the application. (3-23-98)

b. Within fifteen (15) days after the receipt of the pre-permit construction approval application, the Department shall notify the owner or operator in writing of pre-permit construction approval or denial. The Department may deny the pre-permit construction approval application for any reason it deems valid. (3-23-98)

c. Upon receipt of the pre-permit construction approval letter issued by the Department, the owner or operator may begin construction at their own risk as identified in Subsection 213.02.d. Upon issuance of the pre-permit construction approval letter, any and all potential to emit limitations addressed in the pre-permit construction application pursuant to Subsection 213.01.d. shall become enforceable. The owner or operator shall not operate those emissions units subject to permit to construct requirements in accordance with Section 200 unless and until issued a permit pursuant to Section 209. (5-3-03)

d. If the pre-permit construction approval application is determined incomplete or the permit to construct is denied, the Department shall issue an incompleteness or denial letter pursuant to Section 209. If the Department denies the permit to construct, then the owner or operator shall have violated Section 201 on the date it commenced construction as defined in Section 006. The owner or operator shall not contest the final permit to construct decision based on the fact that they have already begun construction. (3-23-98)

214. DEMONSTRATION OF PRECONSTRUCTION COMPLIANCE FOR NEW AND RECONSTRUCTED MAJOR SOURCES OF HAZARDOUS AIR POLLUTANTS.

01. Permitting Authority. For purposes of this section, Sections 112(g) and (j) of the Clean Air Act, and 40 CFR Part 63, the permitting authority shall be the Department. (3-19-99)

02. Definitions. Unless specifically provided otherwise, the definitions for terms set forth in this section shall be the definitions set forth in Section 112 of the Clean Air Act and 40 CFR Part 63 as incorporated by reference into these rules at Section 107. For purposes of determining if a source is a major source of hazardous air pollutants, the definition of potential to emit at Section 006 of these rules shall apply. (3-19-99)

03. Compliance with Federal MACT. All owners or operators of major sources of hazardous air

TAB 2

Department of Environmental Quality
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

AQ-CH-P004

15- Day Pre-Permit Construction Approval Application Completeness Checklist

This checklist is designed to aid the applicant in submitting a complete pre-permit construction approval application. In addition to the items in this checklist, information requested by DEQ during review of the application should be provided in accordance with IDAPA 58.01.01.202.03, or the application may be denied.

I. Actions Needed Before Submitting Application

☑ Refer to the Rule. Read the Pre-Permit Construction requirements contained in IDAPA 58.01.01.213, Rules for the Control of Air Pollution in Idaho.

☑ Refer to DEQ's Pre-Permit Construction Approval Guidance Document. DEQ has developed a guidance document to aid applicants in submitting a complete pre-permit construction approval application. The guidance document is located on DEQ's website (go to http://www.deq.idaho.gov/air/permits_forms/permitting/ptc_prepermit_guidance.pdf

☑ Consult with DEQ Representatives. Schedule a pre-application meeting with DEQ to discuss application requirements before submitting the pre-permit construction approval application. Schedule the meeting by contacting the DEQ Air Permit Hotline at **877-5PERMIT**. The meeting can be in person or on the phone. Refer to IDAPA 58.01.01.213.01b.

☑ Schedule Informational Meeting. Schedule an informational meeting before submitting the pre-permit construction approval application for the purposes of satisfying IDAPA 58.01.01.213.02.a. The purpose for the informational meeting is to provide information about the proposed project to the general public. Refer to IDAPA 58.01.01.213.01.c.

☑ Submit Ambient Air Quality Modeling Protocol. It is required that an ambient air quality modeling protocol be submitted to DEQ at least two (2) weeks before the pre-permit construction approval application is submitted. Contact DEQ's Air Quality Hotline at **877-5PERMIT** for information about the protocol.

☑ Written DEQ Approved Protocol. Written DEQ approval of the modeling protocol must be received before the pre-permit construction approval application is submitted. Refer to IDAPA 58.01.01.213.01.c.

II. Application Content

Application content should be prepared using the checklist below. The checklist is based on the requirements contained in IDAPA 58.01.01.213 and DEQ's Pre-Permit Construction Approval Guidance Document.

☑ Pre-Permit Construction Eligibility and Proof of Eligibility. Pre-permit construction approval is not available for any new Prevention of Significant Deterioration (PSD) major source, any proposed PSD major modification, or any proposed major NSR project in a non-attainment area. Emissions netting and emissions offsets are not allowed to be used. A certified proof of pre-permit construction eligibility must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.

☑ Request to Construct Before Obtaining a Permit to Construct. A letter requesting the ability to construct before obtaining the required permit to construct must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.c.

☑ Apply for a Permit to Construct. Submit a Permit to Construct application using forms available on DEQ's website at http://www.deq.idaho.gov. Refer to IDAPA 58.01.01.213.01.a.

Department of Environmental Quality
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

☑ Permit to Construct Application Fee. The permit to construct application fee of $1000 must be submitted at the time the original pre-permit construction approval application is submitted. Refer to IDAPA 58.01.01.224. If the pre-permit construction approval is denied and a new application is submitted, a new $1,000 application fee will be required to be submitted. The application fee is not transferable or refundable. The application fee can be paid by check, credit card or Electronic Funds Transfer (EFT). If you choose to pay by credit card or EFT, contact DEQ's Fiscal Office at (208) 373-0502 to complete the necessary paper work. If you choose to pay by check, enclose the check with your pre-permit construction approval application.

☑ Notice of Informational Meeting. Within 10 days after the submittal of the pre-permit construction approval application, an informational meeting must be held in at least one location in the region where the stationary source will be located. The information meeting must be made known by notice published at least 10 days before the informational meeting in a newspaper of general circulation in the county in which the stationary source will be located. A copy of this notice, as published, must be submitted with the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.02.a. Additional information regarding the informational meeting is included in DEQ's Pre-Permit Construction Approval Guidance Document. (go to http://www.deq.idaho.gov/air/permits_forms/permitting/ptc_prepermit_guidance.pdf)

☑ Process Description(s). The process or processes for which pre-permit construction approval is requested must be described in sufficient detail and clarity such that a member of the general public not familiar with air quality can clearly understand the proposed project. A process flow diagram is required for each process for which pre-permit construction approval is requested. Refer to IDAPA 58.01.01.213.01.c.

☑ Equipment List. All equipment that will be used for which pre-permit construction approval is requested must be described in detail. Such description includes, but is not limited to, manufacturer, model number or other descriptor, serial number, maximum process rate, proposed process rate, maximum heat input capacity, stack height, stack diameter, stack gas flowrate, stack gas temperature, etc. All equipment that will be used for which pre-permit construction approval is requested must be clearly labeled on the process flow diagram. Refer to IDAPA 58.01.01.213.01.c.

☑ Scaled Plot Plan. A scaled plot plan is required, with the location of each proposed process and the equipment that will be used in each process clearly labeled.

☑ Schedule for Construction. A schedule for construction is required, including proposed dates for commencement and for completion of the project. For phased projects, proposed dates are required for each phase of the project.

☑ Proposed Emissions Limits and Modeled Ambient Concentration for All Regulated Air Pollutants. All proposed emission limits and modeled ambient concentrations for all regulated air pollutants must demonstrate compliance with all applicable air quality rules and regulations. Regulated air pollutants include criteria air pollutants (PM_{10}, SO_x, NO_2, O_3, CO, lead), toxic air pollutants listed pursuant to IDAPA 58.01.01.585 and 586, and hazardous air pollutants listed pursuant to Section 112 of the 1990 Clean Air Act Amendments (go to http://www.epa.gov/ttn/atw/188polls.html). Describe in detail how the proposed emissions limits and modeled ambient concentrations demonstrate compliance with each applicable air quality rule and regulation. It is requested that emissions calculations, assumptions, and documentation be submitted with sufficient detail so DEQ can verify the validity of the emissions estimates. Refer to IDAPA 58.01.01.213.01.c.

☑ Restrictions on a Source's Potential to Emit. Any proposed restriction on a source's potential to emit such that permitted emissions will be either below major source levels or below a significant increase must be described in detail in the pre-permit construction approval application. Refer to IDAPA 58.01.01.213.01.d.

☑ List all Applicable Air Quality Rules and Regulations. All applicable rules and regulations must be cited by the rule or regulation section/subpart that applies for each emissions unit. Refer to IDAPA 58.01.01.213.01.c.

☑ Certification of Pre-Permit Construction Approval Application. The pre-permit construction approval application must be signed by the Responsible Official and must contain a certification signed by the

Responsible Official. The certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Refer to IDAPA 58.01.01.213.01.d and IDAPA 58.01.01.123.

☑ Submit the Pre-Construction Approval Application. Submit the pre-permit construction approval application and application fee to the following address:

Department of Environmental Quality
Air Quality Division
Stationary Source Program
1410 North Hilton
Boise, ID 83706-1255

TAB 3

PRE-APPLICATION MEETING WITH IDEQ

The pre-application meeting was held September 26, 2013 at the Idaho DEQ offices in Boise Idaho.

Present were:

Bill Rogers	State of Idaho DEQ
Cheryl A. Robinson	State of Idaho DEQ
Kenneth L. Hanna	State of Idaho DEQ
Rulon Nielsen	Brigham Young University – Idaho
Andrew Johnson	Brigham Young University – Idaho
Sam Merrick	Brigham Young University –Idaho
Larry Veigel	Heath Engineering Company
Al Oestmann	Trinity Consultants (by phone)

TAB 4

Publication: Standard Journal;**Date:**Nov 19, 2013;**Section:**Comics;**Page Number:**7B[Back][Continuation]

Loan No. xxxxxx6818 T.S. No. 1368459-37 Parcel No. rp07n39e142555 **NOTICE OF TRUSTEE'S SALE** On **March 20, 2014**, at th hour of 11:00am, of said day, at In the foyer o the Fremont county courthouse, 151 west 1st Street North, St. Anthony, Idaho, First Americ Title Insurance Company, as trustee, will sell public auction, to the highest bidder, for cash cashier's check drawn on a State or National Bank, a check drawn by a State or Federal Credit Union, or a check drawn by a State or Federal Savings and Loan Association, Savings Association, or Savings Bank, all payabl at the time of sale, the following described re property, situated in the County of Fremont, state of Idaho, and described as follows, to w COMMENCING AT A POINT 78 RODS WES OF THE NE CORNER OF THE NE1/4NW1/4 OF SECTION 14, TOWNSHIP 7 NORTH, RANGE 39 E.B.M., FREMONT COUNTY, IDA HO, AND RUNNING THENCE SOUTH 270 FEET; THENCE EAST 200 FEET; THENCE NORTHEASTERLY TO A POINT WHICH IS 450 FEET EAST OF THE POINT OF BEGINNING; THENCE WEST 450 FEET TO THE POINT OF BEGINNING. ***home loans, a division of first tennessee bank national association, master servicer, in its capacity as agent for the trustee under the pooling and servicing agreement** Commonly known as 1626 East 400 North Street Saint Anthony Id 83445. Said sale will be made without covenant or warranty, express or implied, regarding title, possession or encumbrances to satisfy the obligation secured by and pursuant to the power of sale conferred in the Deed of Trust executed by Joseph Francis Carroll & Patti Lynn Carroll, Husband & Wife as Grantor, to First American, as Trustee, for the benefit and security of Mortgage Electronic Registration Systems, Inc., ("mers") As Nominee For First Horizon Home Loan Corporation, Its Successors and Assigns as Beneficiary, recorded October 19, 2005, as Instrument No. 498427, Mortgage records of Fremont County, Idaho. THE ABOVE GRANTORS ARE NAMED TO COMPLY WITH SECTION 45-1506(4)(a), IDAHO CODE. NO REPRESENTATION IS MADE THAT THEY ARE, OR ARE NOT, PRESENTLY RESPONSIBLE FOR THIS OBLIGATION. The default for which this sale is to be made is: Failure to pay the monthly payment due April 1, 2012 of interest only plus impounds and subsequent installments due thereafter; plus late charges; together with all subsequent sums advanced by beneficiary pursuant to the terms and conditions of said deed of trust. The estimated balance owing as of this date on the obligation secured by said deed of trust is $99,272.47, including interest, costs and expenses actually incurred in enforcing the obligation thereunder or in this sale, and trustee's fees and/or reasonable attorney's fees as authorized in the promissory note secured by the aforementioned Deed of Trust. First American Title Insurance Company C/o Cal-western Reconveyance Llc P.O. Box 22004 El Cajon Ca 92022-9004 (800)546-1531 Dated: November 4, 2013 Signature/By First American Title Insurance Company. DLPP-434155

Published 11/19/13, 11/26/13, 12/03/13, & 12/10/13
SJ6266

LEGAL

Legal notice

Brigham Young University Idaho, hereafter known as "Owner", is submitting a request to the State of Idaho Department of Environmental Quality (DEQ) seeking permission to raze the existing coal fired central boilers and replace them with gas fired central boilers. The Owner's intent in seeking a "Permit to Construct" is continued compliance with requirements of the Environmental Protection Agency and DEQ. Final approval of the Permit to Construct will be issued by DEQ.

A copy of the Owner's Permit to Construct application filed with DEQ is available for review at the offices of Facilities Planning and Construction Department between the hours of 9:00 am and 5:00 pm.

An informational meeting will be held on Monday, December 2, 2013 from 9:00 to 11:00 AM in the University Operations Building, Room 283 to review the "Permit to Construct".

Owner's Address:
University Operations Building
Facilities Planning and Construction Department
450 South Physical Plant Way
Rexburg, Idaho 83460-8205

Telephone: 208-496-2651
Fax: 208-496-2653
E-Mail: permittoconstruct@byui.edu

Published 11/19/13
SJ6277

FREMONT SCHOOL DISTRICT #215
945 W 1 N
ST. ANTHONY, IDAHO 83445

SCHOOL BUS BID FORM
****** *** *** ****

Fremont School District # 215 is calling for bids for one (1) transit bus forward control and one (1) or more conventional bus or buses. Included herewith are chassis and body specifications and bid forms.

NOTE:

It is intended that Fremont School District #215 will purchase one transit bus and one or more conventional buses at the time the award of bids is made for this bid. However, the option for Fremont School District #215 to purchase additional buses on this same bid and at the same price, if the School District chooses to do so.

Bid Information:

All bids are to be submitted on the enclosed forms, in a sealed envelope with "Bus Bids -1:00 P.M. **December 17, 2013**" marked on the outside. Any deviations from the specifications or conflicts with Federal or State Codes are to be so noted on a sheet and attached to this bid form.
All bids must be at the Office of the Superintendent, at the above address, by 1:00 p.m. on the **17th Day of December 2013**, at which time the bids will be opened and read aloud. The bids will be presented at a regular Board meeting for Board action.

The School District reserves the right to reject any or all bids or to accept the bid or bids deemed best for the School District and to waive any technicality.

Bid Notes:

1. Open to except approved equal to or equivalent to.
2. Early production and availability is up to the factory, however no "flooring" or interest charges will be allowed.

Published 11/16/13 & 11/19/13
SJ6273

NOTICE OF ASSESSMENT
Lenroot Canal Company

NOTICE IS HEREBY GIVEN that at a meeting of th Directors of Lenroot Canal Company held Monday, N 11, 2013, an assessment of $17.00 per share with a mum charge was levied upon the capital stock of the tion. Assessments will be payable by November 30, Lenroot Canal Company.

ANY STOCK UPON WHICH this assessment rema December 1, 2013, will be delinquent and will be cha penalty plus 1 1/2% interest per month until paid in fu

Payment may be made by mail or in person to the

722
Rexbu

Published 11/16/13, 11/19/13, & 11/21/13
SJ6272

IN THE DISTRICT COURT FOR THE SEVENTH JUDICIAL DISTR
STATE OF IDAHO, COUNTY OF BONNEVILLE

RIC OTTEWITTE and NANCY TTEWITTE,
Plaintiff,

V.

. CAROLINE EDWARD, individually; M. AROLINE EDWARD as surviving spouse nd putative personal representative of THE STATE OF ROBERT W. EDWARD, eceased; FIA CARD SERVICES, N.A.; fka MBNA AMERICA BANK, N.A.; BONNEVILLE BILLING & COLLECTIONS, INC.; CAPITAL ONE BANK (USA), N.A.; and JOHN DOES 1-10;
Defendants.

Case No. CV-2013-304

NOTICE OF SALE

DATE OF SALE: December 11, 2013
TIME OF SALE: 10:30 a.m.
PLACE OF SALE: Fremont county sheriff's office
Lobby of the courthouse
151 West 1st Main
St. Anthony, Idaho 83445

Under nand by viture of an Writ of Execution by Sheriff issued on the 23rd c September 2013, out of and under the seal of the above-entitled Court on a in said Court in the above-entitled action on the 22nd day of August 2013, in f above-named plaintiff and against the Defendants, I am commanded and re proceed to notice for sale and to sell at public auction the property describe der of Sale and to applythe proceeds of such sale to the satisfaction of said of Foreclosure with interest thereon, and attorney fees and costs for sale, ar and costs. **The minimum bid is $255,863.85, plus accrued interest and c**
The property directed to be sold is situate in Fremont Count, State of Idah scribed as follows, to wit:
Lot 8, Block 6, Shotgun Village Estates Division No. 2, Fremont Coun shown on the plat recorded May 10, 1971, as Instrument No. 322866.
Lot 10, Block 6, Shotgun Village Estates Division No. 2, Fremont County, I **These properties are commonly known as: 3545 Browning Road, Idaho and 3549 Browning Road, Island Park, Idaho.**
The Sheriff, by certificate of sale, will transfer the right, title, and interest of dants in and to the property at the time of the execution r attachment was le Sheriff will give possession, but does not guarantee clear title nor continued right to the purchaser.
Following issuance of the Sheriff's Certificate of Sale there is a statutory s demption period, during which time judgement Debtor or any redemptioner the above property.If no redemption is made within that six month period, th upon expiration of the redemption period, shall issue its Dees conveying title above property.
NOTICE IS HEREBY GIVEN, that on the 11th day of December 2013, at th 10:30 o' clock a.m. In the foyer of the Fremont County Courthouse, 151 We St. Anthony, Idaho, I will attend, offer and sell at public auction all or so muc above-described property thus directed to be sold as may be necessary to cient fund to pay and satisfy the Judgement of Foreclosure as set out in sai Sale by Sheriff to the highest bidder therefore in lawful money.

DATED THIS 28th day of October 2013.

SHERIFF
Fremont County, Idaho

By: /S/ Vicki Johnson
Deputy

CHARLES C. JUST, ESQ. - ISB 1779
KIPP L. MANWARING, ESQ. - ISB 3817
JUST LAW OFFICE
381 Shoup Avenue
P.O. Box 50271
Idaho Falls, Idaho 83405
Telephone: (208) 523-9106
Facsimile: (208) 523-9146
Attorneys for the Plaintiffs

Published 11/05/13, 11/12/13, & 11/19/13
SJ6256

NOTICE OF TRUSTEE SALE

1. **Date, Time, and Place of Sale.**

   Date: Monday, January 6, 2014

   Time: 9:30 a.m.

   Place: The law offices of Beard St. Clair Gaffney PA, 520 First American Circle, Rexburg, ID 83440.

2. **Instrument to be Foreclosed.** Deed of Trust dated June 11, 1997 and recorded in the office of the Madison County Recorder on June 12, 1997 as Instrument No. 266858 between Michael P. Kennelly and Melanie D. Kennelly, Grantors, and First American Title Company of East Idaho, Trustee, for the benefit of Western Omni Corporation, Beneficiary, to secure the performance of the Grantors' obligations

Lisa McMahon-Myhran, ISB #8963
Jennifer Tait, ISB #8243

TAB 5

SUBMIT AMBIENT AIR QUALITY MODELING PROTOCOL

The protocol was submitted in March of 2013 with approval given April 23, 2013. See Tab 6.

TAB 6

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 NORTH HILTON, BOISE, ID 83706 · (208) 373-0502

C. L. "BUTCH" OTTER, GOVERNOR
CURT FRANSEN, DIRECTOR

April 23, 2013

VIA EMAIL

Mr. Rulon Nielsen, Director
Facilities Planning and Construction
Brigham Young University - Idaho
450 S. Physical Plant Way
Rexburg, Idaho 83460-8205

RE: Facility ID No. 065-00011, Brigham Young University – Idaho, Rexburg
Modeling Protocol Approval, Tier II to PTC Permit Conversion & Boiler Replacement Project

Dear Mr. Nielson:

On February 4, 2013 the Department of Environmental Quality (DEQ) received a dispersion modeling protocol developed on your behalf by Al Oestmann of Trinity Consultants, Inc. (Trinity) in West Burlington, Iowa, for the replacement of three existing stoker coal-fired boilers with three new natural gas-fired boilers, a combustion turbine, and a heat recovery steam generator (HRSG). In addition, one existing 300 kW diesel emergency engine will be replaced by two 500 kW diesel engines. Two 500 kW emergency engines serving the Auditorium (which have not been previously modeled) will also be included in the modeling.

On February 13, 2013, DEQ received by email a proposed NO_2/NOx in-stack ratio of 10.32% for the combustion turbine. On March 19, 2013, DEQ was advised by email that a 40 MMBtu/hr gas turbine will be installed instead of one of three proposed boilers. The email included a proposal to use an NO_2/NOx in-stack ratio of 10.32% for this turbine. Modeling is proposed to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) for emissions of criteria pollutants and Idaho standards for state-regulated Toxic Air Pollutants (TAPs).

The modeling protocol has been reviewed and DEQ has the following comments:

Comment 1. On March 21, 2013, DEQ emailed a zipped electronic copy of an AERMOD-ready meteorological data set to Trinity. The data set was developed using one-minute ASOS wind data and National Weather Service (NWS) surface data collected at the Madison County/Rexburg airport (KRXE) for the years 2008-2012, with NWS upper air data collected at the Boise airport (KBOI) for the same period. These data were processed by DEQ using AERMET v.12345, AERMINUTE v. 11325, and AERSURFACE v. 13016 into a format compatible with the current AERMOD v. 12345. On March 25, 2013, DEQ confirmed for Trinity that the base elevation for the Rexburg surface met data is 1481 meters.

Comment 2. On March 25, 2013, Trinity requested ozone background concentrations for the Rexburg area, in case a Level 3 NOx analysis was needed. DEQ has not yet determined appropriate hourly ozone background data for this project. Should Level 3 analyses be necessary, DEQ recommends that Trinity evaluate available ozone monitoring data and propose background values for DEQ's review and approval.

Comment 3. On April 1, Trinity advised DEQ that the new engine generators are proposed to be routinely tested on a monthly basis, during daylight hours only, and requested DEQ provide a random hourly emissions file for these sources. On April 2, 2013, DEQ received an emailed copy of the BREEZE *.amz file from Trinity, which included the generator exhaust parameters for inclusion in the hourly emissions file. On April 4, 2013, DEQ posted the zipped hourly emissions file for all sources on the DEQ ftp site, as well as a copy of the Excel file used to develop the random hourly file. On April 9, Trinity requested a revised hourly emissions file that included only the generators. On April 10, DEQ emailed the revised hourly emissions file and Excel spreadsheet to Trinity as a zipped electronic file.

To address "daylight only" testing, DEQ obtained daily sunrise and sunset times for Rexburg, determined the latest sunrise and earliest sunset during each month of the year, and used this information to limit the selection range of daylight hours for each month. This provides greater flexibility for routine engine testing compared to selecting a fixed hourly schedule throughout the year, and eliminates potential issues with shifting a fixed schedule during the weeks when daylight savings time is in effect.

Comment 4. On April 22, 2013, Trinity reported success in using the random hourly files for NOx analyses, and requested background concentrations for PM_{10}, $PM_{2.5}$, CO, SO_2, and NO_2. Ambient background concentrations were revised for all areas of Idaho by DEQ in March 2003.[1] Background concentrations for $PM_{2.5}$ and 1-hr NO_2 and SO_2 are under continuing review by DEQ as additional monitoring data becomes available. DEQ recommends using the background concentrations shown in Table P1 for this project.

Table P1. RECOMMENDED BACKGROUND CONCENTRATIONS

Pollutant	Averaging Period	Background Concentration (µg/m^3)	Reference
PM_{10}	24-hr	81	DEQ, March 2003, Rexburg, Idaho value measured on 2/5/99, with moderate winds. Same as Default small town/suburban value.
$PM_{2.5}$	24-hr	19.3	St. Luke's Meridian $PM_{2.5}$ monitor, 2008, 2009, and 2010 finalized data from the U.S. EPA AirData website. The 24-hr concentration is the 3-year average of each year's 98th percentile value.
	Annual	6.3	St. Luke's Meridian $PM_{2.5}$ monitor, 2008, 2009, and 2010 finalized data from the U.S. EPA AirData website. The annual concentration is the 3-year average of the weighted mean value for each year.
CO	1-hr	12 ppm (13,800 µg/m$^{3)}$	DEQ, March 2003, Default urban (pop. 10,000 to 45,000). Rexburg population in 2010 census = 25,484
	8-hr	4.0 ppm (4,600 µg/m^3)	DEQ, March 2003, Default urban (pop. 10,000 to 45,000). Rexburg population in 2010 census = 25,484
NO_2	1-hr	38.5 ppb (73 µg/m^3)	Utah, 2008-2012, Duchesne, Uintah, Washington Counties, EPA AirData, Average of 2nd Highs (28.3 ppb) plus one sigma (10.18 ppb).
	Annual	17 ppb (32 µg/m^3)	DEQ, March 2003, Default small town/suburban.
SO_2	1-hr	9.33 ppb (24.4 µg/m^3)	St. Luke's Meridian SO_2 monitor, 2010, 2011, and 2012 finalized data from the U.S. EPA AirData website. The 1-hr concentration is the average of the 1st high values for the 3-year period.
	Annual	0.003 ppm (8 µg/m^3)	DEQ, March 2003, Default small town/suburban.
Lead (Pb)	Rolling 3-month average	0.03	DEQ, March 2003, Default small town/suburban.

[1] `Hardy, Rick and Schilling, Kevin, *Background Concentrations for Use in New Source Review Dispersion Modeling,* Memorandum to Mary Anderson, March 14, 2003.

Comment 5. Although PM_{10}, $PM_{2.5}$, 1-hr NO_2, 1-hr SO_2, and state-regulated TAPs may be modeled using a concatenated 5-year file, modeling for annual NO_2 impacts must still be done by running each of the 5 years as a separate analysis.

Comment 6. Provide a detailed plot plan with the application, clearly describing the ambient air boundary.

Comment 7. The applicable significant impact levels (SILs)/significant contribution levels (SCLs, the term used in Idaho Air Rules) and NAAQS, along with the "design" values to be used for full impact analyses are shown in Table P1. Please note that the maximum 1st high modeled value is always used for significant impact analyses.

Recent EPA guidance allows for a case-by-case determination of the appropriate modeled "design value" used for $PM_{2.5}$ full impact analyses. If $PM_{2.5}$ ambient impacts are greater than significant, initial full- impact modeling for $PM_{2.5}$ should use the average of the 1st high values reported over the 5-year meteorological period plus background, to demonstrate compliance with the 24-hr $PM_{2.5}$ NAAQS. **If compliance cannot be demonstrated using this conservative approach, please contact DEQ to request a qualitative case-by-case evaluation to see if using a different modeled design value may be appropriate.**

Table P2. APPLICABLE REGULATORY LIMITS FOR CRITERIA POLLUTANT DISPERSION MODELING

Pollutant	Averaging Period	Significant Contribution Levels ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Modeled Value for Full/Cumulative NAAQS Analyses
PM_{10}	24-hour	5.0	150	Maximum 6th highest
$PM_{2.5}$	Annual	0.3	15 (12) [a]	$PM_{2.5}$ –Maximum 1st high
	24-hour	1.2	35	$PM_{2.5}$ –Maximum 1st high **(Maximum 8th high may be used with prior DEQ approval)**
CO	8-hour	500	10,000	Maximum 2nd highest
	1-hour	2,000	40,000	Maximum 2nd highest
NO_2	Annual	1.0	100	Maximum 1st highest
	1-hour [m]	EPA Interim: 4 ppb (7.5 $\mu g/m^3$)	100 ppb (188 $\mu g/m^3$)	Maximum 8th highest
SO_2	Annual	1.0	80	Maximum 1st highest
	24-hour	5	365	Maximum 2nd highest
	3-hour	25	1,300	Maximum 2nd highest
	1-hour	EPA Interim: 3 ppb (7.9 $\mu g/m^3$)	75 ppb (196 $\mu g/m^3$)	Maximum 4th highest
Lead (Pb)	Rolling 3-month average	---	0.15	Maximum 1st highest

[a] The 12 $\mu g/m^3$ annual $PM_{2.5}$ NAAQS will become effective in Idaho when the legislature adjourns *sine die* in the spring of 2014.

Comment 8. Pound-per-hour emission values used in the toxic air pollutant (TAP) dispersion modeling should be double-checked to ensure that they reflect the appropriate averaging period, e.g., noncarcinogenic TAP emissions should reflect a 24-hour average, and carcinogenic TAP emissions should reflect an annual average.

Although listed as a noncarcinogen in the Rules, DEQ has determined that naphthalene is a possible/probable carcinogen. Compliance for naphthalene emissions should be based on the EL or AACC listed in Section 586 for PAH. Please note that the PAH EL and AACC should be applied to each PAH, not total PAHs. To simplify the demonstration, however, if total PAH emissions are below the EL, that is sufficient to show compliance.

Comment 9. Certain TAPs may be exempt from modeling under Section 210.20 of the Idaho Air Rules because the TAPs are regulated under an applicable New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP). For example, DEQ has determined that for area sources of HAPs, modeling of emissions of following TAPs from industrial, commercial, and institutional boilers is not required because emissions of these pollutants are regulated under 40 CFR 63, Subpart JJJJJJ (6J):

- CO limits are a surrogate for organic HAP (i.e., acetaldehyde, acrolein, benzene, dioxins, formaldehyde, and polycyclic organic matter (POM)),
- HCl limits are a surrogate for acid gas HAP,
- TSM or filterable PM limit is a surrogate for non-mercury metallic HAP (i.e., compounds of arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel),
- Mercury, and
- Dioxins/furans.

Questions regarding which TAPs are regulated under applicable NSPS or NESHAPs should be directed to DEQ's Air Toxics Analyst, Carl Brown, at carl.brown@deq.idaho.gov or (208) 373-0206.

Comment 10. The application should provide documentation and justification for all exhaust parameters used in the modeling analyses, clearly showing how stack gas temperatures and flow rates were estimated. In most instances, applicants should use typical parameters, not maximum temperatures and flow rates. Please include the documentation provided by equipment vendors if this is used as the basis for exhaust parameters. Please note that DEQ requires additional justification for exhaust velocities greater than about 50 m/sec.

Comment 11. For minor sources, DEQ has determined that using the beta options within AERMOD for capped and horizontal sources is appropriate, especially for stack emissions subject to building downwash. If beta options are used, however, in addition to assumptions, calculations, and manufacturer data used to determine exhaust temperatures, information supporting the modeled exhaust flow rates for capped or horizontal stacks must also be included in the application.

Comment 12. The proposed receptor grid appears to be reasonable. However, it is the applicant's responsibility to ensure that the extent and spacing of the receptor network assures that the maximum modeled concentration is reasonably resolved. If DEQ conducts verification modeling analyses with a larger or tighter receptor grid and compliance with standards is no longer demonstrated, the permit will be denied.

DEQ's modeling staff considers the submitted dispersion modeling protocol, with resolution of the additional items noted above, to be approved. It should be noted, however, that the approval of this modeling protocol is not meant to imply approval of a completed dispersion modeling analysis. Please refer to the State of Idaho Air Quality Modeling Guideline, which is available on the Internet at http://www.deq.idaho.gov/media/355037-modeling-guideline.pdf, for further guidance.

To ensure a complete and timely review of the final analysis, our modeling staff requests an analysis report be submitted along with electronic copies of all modeling input and output files, including BPIP and AERMAP input and output files. If you have used a graphical user interface (GUI) such as BEEST, BREEZE, or Lakes AERMOD View, please submit the modeling files in the GUI format. If you have any further questions or comments, please contact me at (208) 373-0220 or cheryl.robinson@deq.idaho.gov.

Sincerely,

Cheryl Robinson

Cheryl A. Robinson, P.E.
NSR Modeling Analyst, Air Quality Division

ec: Rulon Nielsen, Director, Facilities Planning and Construction, BYUI, nielsenru@byui.edu
Andy Johnson, Project Coordinator, Facility Planning and Construction, BYUI, johnsona@byui.edu
Kyle Williams, Facilities Manager, Maintenance and Operations, BYUI, williamsk@byui.edu
Responsible Official for all Previous Permitting Actions:
Wayne Clark, Director, Facilities Management Operations, clarkw@byui.edu
Larry Veigel, Heath Engineering Company, lveigel@heatheng.com
Chris Kamerath, Heath Engineering Company, ckamerath@heatheng.com
Al Oestmann, Trinity Consultants, aoestmann@trinityconsultants.com
Michael Simon, Stationary Source Program Manager, michael.simon@deq.idaho.gov
Kevin Schilling, NSR Modeling Coordinator, kevin.schilling@deq.idaho.gov
Bill Rogers, NSR Permit Coordinator, william.rogers@deq.idaho.gov
Rensay Owen, Idaho Falls Regional Air Quality Manager, rensay.owen@deq.idaho.gov

Amanda Benson

From:	Allan Oestmann <AOestmann@TrinityConsultants.com>
Sent:	Tuesday, October 01, 2013 12:06 PM
To:	Larry Veigel
Subject:	Fw: BYU Idaho - Modeling Protocol Approval, Amendment #3 -Engine Generator TAPs regulated under federal NSPS and/or MACT

Forward of Cheryl Robinison 7/2/13 email on toxic air pollutant modeling requirements.

Sincerely,
Al

Allan R. Oestmann

Trinity Consultants, Inc.
Trinity Consultants, Inc.
211 N. Gear Ave., Suite 50
West Burlington, IA 52655
ph. 319-758-0758
fax 319-758-0759
cell 563-260-0838
email: aoestmann@trinityconsultants.com

----- Forwarded by Allan Oestmann/Trinity Consultants on 10/01/2013 12:59 PM -----

From:	<Cheryl.Robinson@deq.idaho.gov>
To:	<AOestmann@TrinityConsultants.com>,
Date:	07/02/2013 04:56 PM
Subject:	BYU Idaho - Modeling Protocol Approval, Amendment #3 -Engine Generator TAPs regulated under federal NSPS and/or MACT

Hi Al,

As we discussed on the telephone today, certain TAPs may be exempt from modeling under Section 210.20 of the Idaho Air Rules because the TAPs are regulated under an applicable New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP).

In accordance with Section 210.20 of the Idaho Air Rules, a demonstration of compliance with state-only TAPs standards is not required for any TAP that is regulated at the time of permit issuance under 40 CFR Part 60 (New Source Performance Standards [NSPS]), 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants [NESHAP], or 40 CFR Part 63 (NESHAP for Source Categories / MACT standards). DEQ has determined that Subpart IIII and Subpart ZZZZ regulate all state-only toxic air pollutants (TAPs) emitted from diesel engine generators. Therefore, no further demonstration of preconstruction compliance is required for TAPs emissions from newer engine generators subject to Subpart IIII and Subpart ZZZZ.

If you have any questions, please don't hesitate to contact me.

Best regards,
Cheryl

Cheryl A. Robinson, P.E.
NSR Air Quality Modeling Analyst
Idaho Department of Environmental Quality
1410 N. Hilton
Boise, Idaho 83706
Tel: (208) 373-0220   Main: (208) 373-0502
cheryl.robinson@deq.idaho.gov
www.deq.idaho.gov

TAB 7

PRE-PERMIT CONSTRUCTION ELIGIBILITY AND PROOF OF ELIGIBILITY

The new BYU-Idaho Boiler Plant is not a PSD major source nor is it a major NR project in a non-attainment area. Tab 9, Attachment 1 (Att. 1 BYUI Em. Inv. (2013_11_17).xlsx on the disk submitted with this application or from the FTP site cited in the cover letter) provides emission calculations that demonstrate the after the Boiler Replacement project is completed emission of individual criteria pollutants will be less than 100 TPY while emissions of CO_{2e} will be below 100,000 metric TPY. The following table summarizes total emissions of each pollutant.

Annual Maximum Emissions							
Pollutant	$PM_{10}/PM_{2.5}$	SO_2	NO_x	CO	VOC	Lead	CO_{2e}
TPY	10.27	1.66	92.60	65.34	79.38	0.0005	90,702

TAB 8

BYU IDAHO | Facilities Planning & Construction
283 University Operations Building · Rexburg, ID · 83460-8205 · Phone: (208) 496-2651

Pre-Permit Construction Approval Application

November 20, 2013

Idaho Department of Environmental Quality
Attn: Bill Rogers
1410 North Hilton
Boise, ID 83706-1255

RE: BRIGHAM YOUNG UNIVERSITY – IDAHO
PRE-PERMIT CONSTRUCTION APPROVAL APPLICATION

Dear Bill:

Brigham Young University – Idaho (BYUI) requests approval to begin construction prior to final approval of the permit to construct (PTC) to replace the existing coal boilers at the BYUI Heat Plant with natural gas-fired boilers and a combustion turbine/heat recovery steam generator. BYUI is eligible for pre-permit construction because it is not a major source under Prevention of Significant Deterioration regulations because:

- No netting of emissions to stay below major source levels is being relied upon,
- No use of offsets pursuant to IDAPA 58.01.01.206 is being used,
- No adverse impact on air quality related values of any Class 1 area will occur.

Documentation of this eligibility in contained in the PTC application attached to this letter. BYUI understands that approval to begin construction prior to PTC approval is subject to the following restriction:

- At our own risk,
- All emission limitations addressed in the application are enforceable,
- Emission units subject to the PTC may not be operated until the PTC is approved.

The PTC application for this project is attached, and it is the belief of BYUI that the application is complete. In addition, all public information notices have been published and all public informational meetings required by IDAPA 58.01.01.213 are being held within the required time periods in this regulation. Dispersion modeling has been performed according a modeling protocol submitted to and approved by IDEQ, and a report documenting the methods used and the results of the modeling are also being submitted with this request to begin construction prior to approval of the PTC.

If you have any questions or comments about this application, please do not hesitate to call me at (208) 496-2520, Al Oestmann (563) 260-0838, or Larry Veigel at (801) 322-0487.

Sincerely,

BRIGHAM YOUNG UNIVERSITY – IDAHO

Kyle Williams

Kyle Williams
Facility Manager Maintenance & Operations

cc: Mr. Larry Veigel, Heath Engineering Company (Salt Lake City, UT)
Mr. Al Oestmann, Trinity Consultants (West Burlington, IA)

TAB 9

APPLY FOR A PERMIT TO CONSTRUCT

The original Permit to Construct was also submitted earlier via email and hard copy to Darrin Pampaian, September 12, 2013.

This application updates design data based on latest information from equipment manufacturers.

This information was not available at the time of the original Permit to Construct Application submittal.

BYU IDAHO | Facilities Planning & Construction
283 University Operations Building • Rexburg, ID • 83460-8205 • Phone: (208) 496-2651

November 19, 2013

Air Quality Program Office – Application Processing
Idaho Department of Environmental Quality
Attn: Darrin Pampanian
1410 North Hilton
Boise, ID 83706-1255

RE: Brigham Young University – Idaho Boiler Replacement Project Permit To Construct Application

Brigham Young University – Idaho (BYUI) is proposing to replace three (3) existing coal-fired boilers with two (2) new natural gas-fired boilers, and to add a natural gas-fired combustion turbine with a heat recovery steam generator (HRSG). All of these new combustion units will utilize ultra-low sulfur diesel (ULSD) as backup fuel, except the HRSG, which is only capable of firing natural gas. This letter and attachments represent the permit to construct (PTC) application for these proposed changes at the BYUI Heat Plant. A dispersion modeling analysis has been conducted and demonstrates compliance with applicable National Ambient Air Quality Standards (NAAQS). The dispersion modeling report is being sent under separate cover.

PROJECT DESCRIPTION

The proposed project includes the replacement of existing coal-fired Boilers No. 2, No. 3, and No. 4 at the BYUI campus heating plant with two new 55 MMBtu/hr natural gas-fired boilers and a 60 MMBtu/hr combustion turbine with a 30 MMBtu/hr HRSG. See Table 1 below for information regarding the heat input capacities of the existing boilers. The project also includes installation of two (2) 500 kW diesel-fired emergency engine generators to serve the Heat Plant and other campus buildings and removal of the existing ash handling system at the Heat Plant. BYUI will not need the ash handling system after replacing the coal-fired boilers with natural gas-fired boilers.

BYUI is also installing a new combination natural gas and oil burner in the existing Boiler No. 5 (of approximately the same heat input capacities) and will relocate, but not otherwise modify this boiler. Boiler No. 5 will be designated Boiler No. 4 after relocation. BYUI is requesting that the modified permit for Boiler No. 5 specify that ULSD is to be used when firing diesel fuel (in order to limit SO_2 emission).

Please see Form FRA for discussion regarding NSPS/NESHAP applicability determinations. In short, the new boilers will comply with 40 CFR 60 Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, and the new turbine and HRSG will comply with 40 CFR 60 Subpart KKKK, *Standards for Performance for Stationary Combustion Turbines*. Note that the definition of a natural gas-fired boiler, oil subcategory in 40 CFR 63 Subpart JJJJJJ (6J), *National Emission Standards for Hazardous Air Pollutants for Industrial , Commercial, and Institutional Boilers Area Sources* states:

> "Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year."

Therefore a 48 hour per year limit is requested for firing oil in the boilers during periodic testing.

Table 1. Existing BYUI Heating Plant Boilers

November 19, 2013

Boiler	Manufacturer	Model	Permitted Fuel(s)	Heat Input (MMBtu/hr)	Installation Date
Boiler No. 2	Erie City Iron Works	16792 H.S.B	Bituminous Coal	26.7	1963
Boiler No. 3	Union Iron Works	234-28	Bituminous Coal	40	1966
Boiler No. 4	Keeler	Watertube MK	Bituminous Coal	46.7	1973
Boiler No. 5	Indeck/Volcano	02-40-X	Natural Gas / No. 2 Oil	51 Gas / 48.25 Oil	2001

PERMIT APPLICATION

Attachment 1 presents BYUI potential emissions both before (as currently permitted) and after the changes described above. BYUI requests a limit on gas usage in the natural gas-fired boilers (including the HRSG) of 1,034 x 10^6 ft^3/yr, and a facility-wide natural gas usage limit of 1,618.44 x 10^6 ft^3/yr, and a ULSD limit of 472 x 10^3 gal/yr for Boilers No. 2, No. 3, No. 4, and the combustion turbine. The HRSG will fire only natural gas. BYUI will remain a Title V minor source with potential emissions of nitrogen oxides (NO_x) of less than 100 TPY (92.6 TPY). The fuel usage limits above are intended to avoid major source status for Prevention of Significant Deterioration for greenhouse gases (CO_{2e}) by limiting emissions of CO_{2e} to less than 100,000 TPY. Emissions for the boilers (including the HRSG) and the combustions turbine are calculated using manufacturer's emissions data. Where manufacturer's emission data is not available, appropriate emission factors from the EPA publication AP-42, Fifth Edition, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* are used. Emissions of CO, NO_x, and PM for the two new generators are based on EPA-certified manufacturer's emission guarantees (see Attachment 8). Other calculations, including post-project uncontrolled emissions, modeled emission rates for sources when firing ULSD, the modeled emission rates for sources when firing natural gas, and air toxics emissions are also included in an Excel spreadsheet titled BYUI Em Inv.xlsx available at: ftp.heatheng.com, Username: BYUIboiler2, Password: emodel. A summary of maximum annual permitted emissions appears below.

Maximum Annual Emissions							
Pollutant	PM10/PM2.5	SO_2	NO_x	CO	VOC	Lead	CO_{2e}
TPY	10.27	1.66	92.60	65.34	79.38	0.0005	90,702

The Idaho Department of Environmental Quality (IDEQ) permit forms necessary for a complete permit application are in Attachment 2. As indicated on Form CSPTC, not all IDEQ permit forms have been utilized because the information

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required in them is provided in another submitted document, spreadsheet file, or model file. Attachment 3 contains drawings of the modified Heat Plant building. An AutoCAD DWG file that depicts the current Heat Plant (with existing equipment shown) is available on the ftp site cited above. Attachment 4 contains manufacturer's specifications and emission data for the generators that are being installed as part of this project. A list of attachments follows:

Attachment 1 - BYUI Emission Inventory
Attachment 2 – IDEQ Permit Application Forms
Attachment 3 – Heat Plant Drawings
Attachment 4 – Turbine Design Specifications
Attachment 5 – Heat Recovery Steam Generator Design Specifications
Attachment 6 – Design Specifications for Boilers 2 and 3
Attachment 7 - Design Specifications for Retrofit Boiler 4
Attachment 8 – Generator Design Specifications

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at (208) 496-2520, Larry Veigel at (801) 322-0487, or Al Oestmann at (563) 260-0838.

Sincerely,

BRIGHAM YOUNG UNIVERSITY - IDAHO

Kyle Williams
Facility Manager Maintenance & Operations

Attachments

cc: Mr. Larry Veigel, Heath Engineering (Salt Lake City, UT)
Mr. Al Oestmann, Trinity Consultants (West Burlington, IA

ATTACHMENT 1

Existing and Post-Project Emission Inventory

Attachment 1
Brigham Young University - Existing and Post-Project Emissions Inventory

Natural Gas

900 Btu/ft^3 NG				PM$_{10}$/PM$_{2.5}$					SO$_2$					NO$_x$				
	Heat Input	Nat. Gas Usage	Operation	Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	Em. Rate	Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	Em. Rate	Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	Em. Rate
ID	(10^6 Btu/hr)	(10^6 ft^3/hr)	(Hr/Yr)		Note 7		(lb/hr)	(TPY)		Note 1		(lb/hr)	(TPY)		Note 7		(lb/hr)	(TPY)
Boiler 2	55.0	0.0611	4,900	Mfgr.	0.01125	lb/MMBtu	0.619	1.52	Table 1.4-2	0.6	lb/10^6 ft^3	0.037	0.09	Mfgr.		lb/hr	2.911	7.13
Boiler 3	55.0	0.0611	4,900	Mfgr.	0.01125	lb/MMBtu	0.619	1.52	Table 1.4-2	0.6	lb/10^6 ft^3	0.037	0.09	Mfgr.		lb/hr	2.911	7.13
Turbine	60.0	0.0667	8,760	Table 3.1-2a	0.0066	lb/MMBtu	0.396	1.73	Table 3.1-2a	0.00008	lb/MMBtu	0.005	0.02	Mfgr.	0.10	lb/MMBtu	6.000	26.28
HRSG	30.0	0.0333	4,900	Mfgr.	0.0135	lb/MMBtu	0.405	0.99	Table 1.4-2	0.6	lb/10^6 ft^3	0.020	0.05	Mfgr.		lb/hr	4.215	10.33
Boiler 4 (Note 2) Natural Gas	50.0	0.0556	4,900	Mfgr.	0.01125	lb/MMBtu	0.563	1.38	Table 1.4-2	0.6	lb/10^6 ft^3	0.033	0.08	Mfgr.		lb/hr	2.700	6.62
		Blrs/Turbine/HRSG Subtotal					**2.60**	**7.14**				**0.13**	**0.33**				**18.74**	**57.48**
Heat/Chilled H$_2$O Emer. Diesel Gen.				Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	500 hr/yr	Em. Factor Source	Em. Factor[6]	Max. Fuel Usage	Em. Rate	500 hr/yr	Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	500 hr/yr
	kW	HP			(g/hp-hr)		(lb/hr)	(TPY)		(15 ppm S)	(62.6 gal/hr)	(lb/hr)	(TPY)		(g/hp-hr)		(lb/hr)	(TPY)
EG481	500	757	500	Mfgr.	0.14	g/hp-hr	0.234	0.06	Mass Balance	0.0002115	lb/gal	0.013	0.00	Mfgr.	4.00	g/hp-hr	6.676	1.67
EG482	500	757	500	Mfgr.	0.14	g/hp-hr	0.234	0.06	Mass Balance	0.0002115	lb/gal	0.013	0.00	Mfgr.	4.00	g/hp-hr	6.676	1.67
EG483	500	757	500	Mfgr.	0.14	g/hp-hr	0.234	0.06	Mass Balance	0.0002115	lb/gal	0.013	0.00	Mfgr.	4.00	g/hp-hr	6.676	1.67
EG484	500	757	500	Mfgr.	0.14	g/hp-hr	0.234	0.06	Mass Balance	0.0002115	lb/gal	0.013	0.00	Mfgr.	4.00	g/hp-hr	6.676	1.67
Boilers 2, 3, 4, 5, HRSG, and Turbine Diesel PM$_{10}$ Emissions (see below)							7.92	1.58				0.34	0.07				47.29	9.46
All OtherExisting BYUI Sources																		
Emer. Generators (500 hr/yr ea.) (Note 3)							5.25	1.32					1.25					18.98
Paint Booths (Note 4)							0.48	1.53					--					--
Welding							0.003	0.02					--					--
Ash Handling System							1.00	0.37					--					--
		Total Future Emissions (TPY)					**18.19**	**10.27**				**0.53**	**1.66**				**92.73**	**92.60**
		Existing Permit Tot. Em. (TPY)					26.1	24.96				100.32	99.79				120.7	80
		Ex. Prmt Coal Em (9300 TPY-4.36 TPH)		Emissions for criteria pollutants from existing coal boilers are included above in Existing Permit Total Emissions.														
		Incr./Decr. Current to Future (TPY)					**-7.91**	**-14.69**				**-99.79**	**-98.13**				**-27.97**	**12.60**

Natural Gas

900 Btu/ft^3 NG				CO					VOC					Pb			
	Heat Input	Nat. Gas Usage	Operation	Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	Em. Rate	Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	Em. Rate	Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate
ID	(10^6 Btu/hr)	(10^6 ft^3/hr)	(Hr/Yr)		Note 7		(lb/hr)	(TPY)		Note 7		(lb/hr)	(TPY)		Note 7		(lb/hr)
Boiler 2	55.0	0.0611	4,900	Mfgr.		lb/hr	3.234	7.92	Mfgr.	0.006	lb/MMBtu	0.330	0.81	Table 1.4-2	0.0005	lb/10^6 ft^3	0.00003
Boiler 3	55.0	0.0611	4,900	Mfgr.		lb/hr	3.234	7.92	Mfgr.	0.006	lb/MMBtu	0.330	0.81	Table 1.4-2	0.0005	lb/10^6 ft^3	0.00003
Turbine	60.0	0.0667	8,760	Mfgr.	0.092	lb/MMBtu	5.490	24.05	Table 3.1-2a	0.0021	lb/MMBtu	0.126	0.55	Table 3.1-2a	N/A	lb/10^6 ft^3	N/A
HRSG	30.0	0.0333	4,900	Mfgr.		lb/hr	4.215	10.33	Table1.4-2	5.5	lb/10^6 ft^3	0.183	0.45	Table 1.4-2	0.0005	lb/10^6 ft^3	0.00002
Boiler 4 (Note 2) Natural Gas	50.0	0.0556	4,900	Mfgr.		lb/hr	3.000	7.35	Mfgr.	0.006	lb/MMBtu	0.300	0.74	Table 1.4-2	0.0005	lb/10^6 ft^3	0.00003
		Blrs/Turbine/HRSG Subtotal					**19.17**	**57.57**				**1.27**	**3.35**				**0.00011**
Heat/Chilled H$_2$O Emer. Diesel Gen.				Em. Factor Source	Em. Factor	Em. Factor Units	Em. Rate	500 hr/yr	Em. Factor Source	Em. Factor		Em. Rate	500 hr/yr				
	kW	HP					(lb/hr)	(TPY)		(lb/hp-hr)		lb/hr	(TPY)				
EG481	500	757		Mfgr.	0.50	g/hp-hr	0.834	0.21	Table 3.3-1	0.0025		1.903	0.48		N/A		N/A
EG482	500	757		Mfgr.	0.50		0.834	0.21	Table 3.3-1	0.0025		1.903	0.48		N/A		N/A
EG483	500	757		Mfgr.	0.50		0.834	0.21	Table 3.3-1	0.0025		1.903	0.48		N/A		N/A
EG484	500	757		Mfgr.	0.50		0.834	0.21	Table 3.3-1	0.0025		1.903	0.48		N/A		N/A
Diesel Emssions (See Below)							14.52	2.90				0.03	0.01		0.0E+00		0.00021
All OtherExisting BYUI Sources																	
Emer. Generators (500 hr/yr ea.) (Note 3)								4.03					1.80				0.01
Paint Booths (Note 4)								--				35.33	74.117				--
Welding								--					--				--
Ash Handling System								--					--				--
		Total Future Emissions (TPY)					**22.51**	**65.34**				**44.24**	**79.38**				**0.0005**
		Existing Permit Tot. Em. (TPY)					41.67	43.84				42.95	84.21				6.23
		Ex. Prmt Coal Em (9300 TPY-4.36 TPH)					Emissions for criteria pollutants from existing coal boilers are included above in Existing Permit Total Emissions.										
		Incr./Decr. Current to Future (TPY)					**-19.16**	**21.50**				**1.29**	**-4.83**				**-6.23**

NG	**10^6 ft3/yr**	
Blr2	299.44	
Blr3	299.44	
Blr4	272.22	
Turbine	584.00	
HRSG	163.33	NG limit for Blrs (10^6 ft3/yr)
Total	**1618.44**	**1034**
Diesel	**10^3 gal/yr**	
Blr2	162.21	
Blr3	162.21	
Blr4	147.46	
Turbine	176.95	
HRSG	0.00	Diesel limit for Blrs (10^3 gal/yr)
Total	**648.82**	**472**

Attachment 1

Brigham Young University - Existing and Post-Project Emissions Inventory

No.2 Diesel (ULSD)5

135,630 Btu/gal Diesel (BYUI Fuel Supplier)

ID	Heat Input (10^6 Btu/hr)	ULSD (10^3 gal/hr)	Operation (Hr/Yr)	PM_{10} Em. Factor Source	PM_{10} Em. Factor (Note 7)	PM_{10} Em. Factor Units	PM_{10} Em. Rate (lb/hr)	PM_{10} Em. Rate (TPY)
Boiler 2	55.0	0.4055	400	Mfgr.	0.045	lb/MMBtu	2.475	0.50
Boiler 3	55.0	0.4055	400	Mfgr.	0.045	lb/MMBtu	2.475	0.50
Turbine	60.0	0.4424	400	Table3.1-2a	0.012	lb/MMBtu	0.720	0.14
HRSG	30.0	0.2212	0		NA			
Boiler 4	50.0	0.3687	400	Mfgr.	0.045	lb/MMBtu	2.250	0.45
Total							**7.92**	**1.58**

ID	$PM_{2.5}$ Em. Factor Source	$PM_{2.5}$ Em. Factor (Note 7)	$PM_{2.5}$ Em. Factor Units	$PM_{2.5}$ Em. Rate (lb/hr)	$PM_{2.5}$ Em. Rate (TPY)
Boiler 2	Mfgr.	0.0054	lb/MMBtu	0.297	0.00
Boiler 3	Mfgr.	0.0054	lb/MMBtu	0.297	0.00
Turbine	Table3.1-2a	0.012	lb/MMBtu	0.720	0.00
HRSG		NA			
Boiler 4	Mfgr.	0.0054	lb/MMBtu	0.270	0.00
Total				**1.58**	**0.00**

ID	SO_2 Em. Factor Source	SO_2 Em. Factor	SO_2 Em. Factor Units	SO_2 Em. Rate (lb/hr)	SO_2 Em. Rate (TPY)
Boiler 2	Table 1.3-1	0.213	lb/10^3 gal	0.086	0.02
Boiler 3	Table 1.3-1	0.213	lb/10^3 gal	0.086	0.02
Turbine	Table 3.1-2a	0.0015	lb/MMBtu	0.091	0.02
HRSG		NA			
Boiler 4	Table 1.3-1	0.213	lb/10^3 gal	0.079	0.02
Total				**0.34**	**0.07**

ID	NO_x Em. Factor Source	NO_x Em. Factor (Note 7)	NO_x Em. Factor Units	NO_x Em. Rate (lb/hr)	NO_x Em. Rate (TPY)
Boiler 2	Mfgr.		lb/hr	7.910	1.58
Boiler 3	Mfgr.		lb/hr	7.910	1.58
Turbine	Mfgr.	0.402	lb/MMBtu	24.120	4.82
HRSG		NA			
Boiler 4	Mfgr.		lb/hr	7.350	1.47
Total				**47.29**	**9.46**

135,630 Btu/gal Diesel (BYUI Fuel Supplier)

ID	Heat Input (10^6 Btu/hr)	ULSD (10^3 gal/hr)	Operation (Hr/Yr)	CO Em. Factor Source	CO Em. Factor (Note 7)	CO Em. Factor Units	CO Em. Rate (lb/hr)	CO Em. Rate (TPY)
Boiler 2	55.0	0.4055	400	Mfgr.		lb/hr	3.024	0.60
Boiler 3	55.0	0.4055	400	Mfgr.		lb/hr	3.024	0.60
Turbine	60.0	0.4424	400	Mfgr.	0.0945	lb/MMBtu	5.670	1.13
HRSG	30.0	0.2212	0		N/A			
Boiler 4	50.0	0.3687	400	Mfgr.		lb/hr	2.805	0.56
Total							**14.524**	**2.90**

ID	VOC Em. Factor Source	VOC Em. Factor (Note 7)	VOC Em. Factor Units	VOC Em. Rate (lb/hr)	VOC Em. Rate (TPY)
Boiler 2	Mfgr.	0.006	lb/MMBtu	0.002	0.00
Boiler 3	Mfgr.	0.006	lb/MMBtu	0.002	0.00
Turbine	Table 3.1-2a	0.00041	lb/MMBtu	0.025	0.005
HRSG		N/A			
Boiler 4	Mfgr.	0.006	lb/MMBtu	0.002	0.00
Total				**0.03**	**0.01**

ID	Pb Em. Factor Source	Pb Em. Factor (Note 7)		Pb Em. Rate (lb/hr)	Pb Em. Rate (TPY)
Boiler 2		N/A		0	0.00
Boiler 3		N/A		0	0.00
Turbine	Table 3.1-2a	0.000014	lb/MMBtu	0.00021	0.00004
HRSG		N/A			0.00
Boiler 4		N/A		0.000	0.00
Total				**0.00021**	**0.00004**

900 Btu/ft^3 NG

ID	Heat Input (10^6 Btu/hr)	Nat. Gas Usage (10^6 ft^3/hr)	Operation (Hr/Yr)	CO_2 Em. Factor Source	CO_2 Em. Factor	CO_2 Em. Factor Units	CO_2 Em. Rate (lb/hr)	CO_2 Em. Rate (TPY)
Boiler 2	55.0	0.0611	4,900	Table 1.4-2	120,000	lb/10^6 ft^3	7,333	17,967
Boiler 3	55.0	0.0611	4,900	Table 1.4-2	120,000	lb/10^6 ft^3	7,333	17,967
Turbine	60.0	0.0667	8,760	Table 3.1-2a	110	lb/MMBtu	6,600	28,908
HRSG	30.0	0.0333	4,900	Table 1.4-2	120,000	lb/10^6 ft^3	4,000	9,800
Boiler 4	50.0	0.0556	4,900	Table 1.4-2	120,000	lb/10^6 ft^3	6,667	16,333
Boilers Subtotal								90,975
Heat/Chilled H_2O Emer. Diesel Gen.								
	kW	HP			lb/hp-hr			500 hr/yr
EG481	500	757	500	Table 3.3-1	1.15		871	218
EG482	500	757	500	Table 3.3-1	1.15		871	218
EG483	500	757	500	Table 3.3-1	1.15		871	218
EG484	500	757	500	Table 3.3-1	1.15		871	218
All OtherExisting BYUI Sources								
Emer. Generators (500 hr/yr ea.) (Note 3)					1.15		2,372	593
Paint Booths (Note 4)								--
Welding								--
Ash Handling System								--
Total FutureEmissions (TPY)								**92,438**
Ex. Prmt Coal Em. (9300 TPY-4.36 TPH)				Table 1.1-20	4810		20,972	22,367
Exist. Permit - Total Emissions (TPY)							30,011	39,293
Incr./Decr. Current to Future (TPY)							**-30,011**	**53,145**

ID	CH_4 Em. Factor Source	CH_4 Em. Factor	CH_4 Em. Factor Units	CH_4 Em. Rate (lb/hr)	CH_4 Em. Rate (TPY)
Boiler 2	Table 1.4-2	2.3	lb/10^6 ft^3	0.141	0.34
Boiler 3	Table 1.4-2	2.3	lb/10^6 ft^3	0.141	0.34
Turbine	Table 3.1-2a	N/A	lb/MMBtu	0.000	0.00
HRSG	Table 1.4-2	2.3	lb/10^6 ft^3	0.077	0.19
Boiler 4	Table 1.4-2	2.3	lb/10^6 ft^3	0.128	0.31
Boilers Subtotal					1.19
Emer. Generators (500 hr/yr ea.) (Note 3)				N/A	N.A
Paint Booths (Note 4)				--	--
Welding				--	--
Ash Handling System				--	--
Total FutureEmissions (TPY)					**1.19**
Ex. Prmt Coal Em. (9300 TPY-4.36 TPH)	Table 1.1-19	0.06		45.4	113.6
Exist. Permit - Total Emissions (TPY)				45.5	113.9
Incr./Decr. Current to Future (TPY)					**-112.7**

ID	N_2O Em. Factor Source	N_2O Em. Factor	N_2O Em. Factor Units	N_2O Em. Rate (lb/hr)	N_2O Em. Rate (TPY)
Boiler 2	Table 1.4-2	2.2	lb/10^6 ft^3	0.134	0.33
Boiler 3	Table 1.4-2	2.2	lb/10^6 ft^3	0.134	0.33
Turbine	Table 1.4-2	N/A		0.000	0.00
HRSG	Table 1.4-2	2.2	lb/10^6 ft^3	0.073	0.18
Boiler 4	Table 1.4-2	2.2	lb/10^6 ft^3	0.122	0.30
Boilers Subtotal					1.14
Emer. Generators (500 hr/yr ea.) (Note 3)					N.A
Paint Booths (Note 4)					--
Welding					--
Ash Handling System					--
Total FutureEmissions (TPY)					**1.138**
Ex. Prmt Coal Em. (9300 TPY-4.36 TPH)	Table 1.1-19	0.04		30.3	75.7
Exist. Permit - Total Emissions (TPY)				30.4	76.0
Incr./Decr. Current to Future (TPY)					**-74.9**

CO_{2e} GHG	(Note 5) Factor	GHG (Metric Tons/Yr)	CO2e (Metric Tons/Yr)
CO_2	1	83,860	83,860
CH4	21	1.08	23
N_2O	310	1.03	320
Total CO2e (TPY)		83,862	84,203
Existing CO_{2e}			
CO_2	1	35,647	32,339
CH4	21	103	1,968
N_2O	310	69	19,390
Total CO2e (TPY)		35,819	53,697
Metric Tons (MT) = T * 0.9072			
Total FutureEmissions (TPY)		**90,345**	**90,702**
Ex. Prmt Coal Em. (9300 TPY-4.36 TPH)		35,819	53,697
Incr./Decr. Current to Future (TPY)		**54,526**	**37,006**

135,630 Btu/gal Diesel (BYUI Fuel Supplier)

ID	Heat Input (10^6 Btu/hr)	ULSD (10^3 gal/hr)	Operation (Hr/Yr)	CO_2 Em. Factor Source	CO_2 Em. Factor	CO_2 Em. Factor Units	CO_2 Em. Rate (lb/hr)	CO_2 Em. Rate (TPY)
Boiler 2	55.0	0.4055	400	Table 1.3-12	22,300	lb/10^3 gal	9,043	1,809
Boiler 3	55.0	0.4055	400	Table 1.3-12	22,300	lb/10^3 gal	9,043	1,809
Turbine	60.0	0.4424	400	Table 3.1-2a	157	lb/MMBtu	9,420	1,884
HRSG	30.0	0.2212	0		NA			
Boiler 4	50.0	0.3687	400	Table 1.3-12	22,300	lb/10^3 gal	8,221	1,644
Total for Diesel								**7145.37**

ID	CH_4 Em. Factor Source	CH_4 Em. Factor	CH_4 Em. Factor Units	CH_4 Em. Rate (lb/hr)	CH_4 Em. Rate (TPY)
Boiler 2	Table 3.3-1	NA		0.000	0.00
Boiler 3	Table 3.3=1	NA		0.000	0.00
Turbine	Table3.1-2a	NA		0.000	0.00
HRSG		NA			
Boiler 4	Table 3.3=1	NA		0.000	0.00
Total for Diesel					**0.00**

ID	N_2O Em. Factor Source	N_2O Em. Factor	N_2O Em. Factor Units	N_2O Em. Rate (lb/hr)	N_2O Em. Rate (TPY)
Boiler 2	Table 1.3-8	0.26	lb/10^3 gal	0.105	0.02
Boiler 3	Table 1.3-8	0.26	lb/10^3 gal	0.105	0.02
Turbine	Table 3.1-2a	NA		0.000	0.00
HRSG		NA			
Boiler 4	Table 1.3-8	0.26	lb/10^3 gal	0.096	0.02
Total for Diesel					**0.06**

CO2e GHG	(Note 5) Factor	GHG (Metric Tons/Yr)	CO2e (Metric Tons/Yr)
CO_2	1	6,482	6,482
CH4	21	0	0
N_2O	310	0.1	17
Total CO2e (TPY)		6,482	6,500
Total for Diesel		**6482**	**6,500**

Note 1. Sulfur content of natural gas assumed to be 85 ppmw

Note 2. Boiler 4 is existing Boiler 5. Under current permit conditions Boiler 5 operates 8360 hr/yr on natural gas (383.877 10^6 ft^3/yr), and up to 400 hr/yr on No.2 fuel oil (128.571 10^3 gal/yr). Hourly CO_2, CH_4, and N_2O emissions are calculated using natural gas for 8760 hr/yr.

Note 3. Emissions from an existing 300 kW emergency generator at the Heat Plant are included in this total. This generator will be removed and replaced by two new 500 kW generators (EG482 and EG4842). Two of the 500 kW generators (EG481 and EG482)shown here as being part of this project are in fact installed at this time, but are not included in the existing generator emissions shown here because installation occurred after the last update of the Tier II permit.

Note 4. Physical Facilities #1 Spray Booth currently has no operational restriction. The emission totals for paint spray booths shown here are based on restricting this Spray Booth to 40000 gall/yr throughput (equivalent to 8000 hr/hr at 5.0 gal/hr).

Note 5. Source: Table A-1 to Subpart A Part 98 - Global Warming Potentials

Note 6. Ultra-low Sulfur Diesel, S content = 15 ppmw, 31.3 gal/hr @ 7.05 lb/gal

Note 7. All emission factors supplied by the manufacturer have been multiplied by 1.5 to provide a safety factor as boiler performance degrades over the life of the boiler. Manufacturer's emission factors are supplied in Attachment X of the permit application.

ATTACHMENT 2

Idaho Department of Environmental Quality Permit Application Forms

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Cover Sheet for Air Permit Application – Permit to Construct **Form CSPTC**

Please see instructions on page 2 before filling out the form.

COMPANY NAME, FACILITY NAME, AND FACILITY ID NUMBER

1. Company Name	Brigham Young University - Idaho		
2. Facility Name	Brigham Young University - Idaho	3. Facility ID No.	065-00011
4. Brief Project Description - One sentence or less	Replacement of three coal-fired boilers (26.7, 40.0, and 46.7 MMBtu/hr) with two natural gas-fired boilers (both 55 MMBtu/hr), a gas turbine (60 MMBtu/hr) with heat recovery steam generator (30 MMBtu/hr), relocation of an existing boiler with a new combination gas/oil burner (50 MMBtu/hr), and two generators.		

PERMIT APPLICATION TYPE

5. ☐ New Source ☒ New Source at Existing Facility ☐ PTC for a Tier I Source Processed Pursuant to IDAPA 58.01.01.209.05.c
☐ Unpermitted Existing Source ☐ Facility Emissions Cap ☐ Modify Existing Source: Permit No.:_____ Date Issued:_____
☐ Required by Enforcement Action: Case No.:_____

6. ☒ Minor PTC ☐ Major PTC

FORMS INCLUDED

Included	N/A	Forms		DEQ Verify
☒	☐	Form CSPTC – Cover Sheet		☐
☒	☐	Form GI – Facility Information		☐
☒	☐	Form EU0 – Emissions Units General		☐
☒	☐	Form EU1– Industrial Engine Information	Please specify number of EU1s attached: 2	☐
☐	☒	Form EU2– Nonmetallic Mineral Processing Plants	Please specify number of EU2s attached: _____	☐
☐	☒	Form EU3– Spray Paint Booth Information	Please specify number of EU3s attached: _____	☐
☐	☒	Form EU4– Cooling Tower Information	Please specify number of EU3s attached: _____	☐
☒	☐	Form EU5 – Boiler Information	Please specify number of EU4s attached: 5	☐
☐	☒	Form CBP– Concrete Batch Plant	Please specify number of CBPs attached: _____	☐
☐	☒	Form HMAP – Hot Mix Asphalt Plant	Please specify number of HMAPs attached: _____	☐
☐	☒	PERF – Portable Equipment Relocation Form		☐
☐	☒	Form AO – Afterburner/Oxidizer		☐
☐	☒	Form CA – Carbon Adsorber		☐
☐	☒	Form CYS – Cyclone Separator		☐
☐	☒	Form ESP – Electrostatic Precipitator		☐
☐	☒	Form BCE– Baghouses Control Equipment		☐
☐	☒	Form SCE– Scrubbers Control Equipment		☐
☐	☒	Form VSCE – Venturi Scrubber Control Equipment		☐
☐	☒	Form CAM – Compliance Assurance Monitoring		☐
☒	☐	Forms EI-– Emissions Inventory (Data from this form is included in BYUI Em Inv.xlsx)		☐
☒	☐	PP – Plot Plan		☐
☒	☐	Forms MI1 – MI4 – Modeling (Data from these forms is included in BYUI Em Inv.xlsx)		☐
☒	☐	Form FRA – Federal Regulation Applicability		☐

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

General Information **Form GI**
Revision 7
2/18/10

Please see instructions on page 2 before filling out the form.

All information is required. If information is missing, the application will not be processed.

IDENTIFICATION

1. Company Name	2. Facility Name:
Brigham Young University - Idaho	Brigham Young University - Idaho

3. Brief Project Description:	Replacement of coal-fired boilers with natural gas-fired boilers and two emergency generators

FACILITY INFORMATION

4. Primary Facility Permit Contact Person/Title	Kyle Williams		Facility Manager Maintenance & Operations	
5. Telephone Number and Email Address	208-496-2520		williamsk@byui.edu	
6. Alternate Facility Contact Person/Title				
7. Telephone Number and Email Address				
8. Address to Which the Permit Should be Sent	525 S. Center			
9. City/County/State/Zip Code	Rexburg	Madison	Idaho	83460-8205
10. Equipment Location Address (if different than the mailing address above)				
11. City/County/State/Zip Code				
12. Is the Equipment Portable?	☐ Yes ☒ No			
13. SIC Code(s) and NAICS Code	Primary SIC: 8221	Secondary SIC:	NAICS: 611310	
14. Brief Business Description and Principal Product	College or University - Post-secondary Education			
15. Indentify any adjacent or contiguous facility that this company owns and/or operates	None			
16. Specify the reason for the application	☒ Permit to Construct (PTC) For Tier I permitted facilities only: If you are applying for a PTC then you must also specify how the PTC will be incorporated into the Tier I permit. ☐ Incorporate the PTC at the time of the Tier I renewal ☐ Co-process the Tier I modification and PTC ☐ Administratively amend the Tier I permit to incorporate the PTC upon your request (IDAPA 58.01.01.209.05.a, b, or c) ☐ Tier I Permit ☐ Tier II Permit ☐ Tier II/Permit to Construct			

CERTIFICATION

In accordance with **IDAPA 58.01.01.123** (Rules for the Control of Air Pollution in Idaho), I certify based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

17. Responsible Official's Name/Title	Kyle Williams	Facility Manager Maintenance & Operations	
18. Responsible Official's Signature	Kyle Williams	Date:	11/20/2013

19. ☒ Check here to indicate that you would like to review the draft permit prior to final issuance.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3. Facility ID No:
Brigham Young University - Idaho	Brigham Young University - Idaho	065-00011
4. Brief Project Description:	Replacement of 3 coal-fired boilers with 3 nat. gas-fired boilers and a gas turbine/HRSG	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION		
5.	Emissions Unit (EU) Name:	GAS TURBINE
6.	EU ID Number:	EU01
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	TBD
9.	Model:	
10..	Maximum Capacity:	60 MMBTU/HR
11.	Date of Construction:	ON OR ABOUT OCTOBER 1, 2013
12.	Date of Modification (if any):	
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT			
14. Control Equipment Name and ID:			
15. Date of Installation:		16. Date of Modification (if any):	
17. Manufacturer and Model Number:			
18. ID(s) of Emission Unit Controlled:			
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)		
22.	Actual Operation:	8,760 HR/YR
23.	Maximum Operation:	8,760 hr/yr

REQUESTED LIMITS		
24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☒ Material Usage Limit(s):	NG:584.0 10E6 FT3/YEAR,DIESEL 176.95 10E3 GAL/YR
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AVIODANCE OF MAJOR SOURCE STATUS FOR CO2E

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Engine Information **Form EU1**
Revision 8
1/15/10

Please see instructions on page 2 before filling out the form.

IDENTIFICATION			
1. Company Name: Brigham Young University - Idaho	2. Facility Name: Brigham Young University - Idaho		
3 Brief Project Description:	Replacement of coal-fired boilers with natural gas-fired boilers.		
ENGINE (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS			
4. Type of Unit:	☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #: Date Issued:		
5. Engine Displacement:	2.69 (liters per cylinder)	6. Ignition Type:	☒ Compression ☐ Spark
7. Use	☒ Emergency ☐ Non-Emergency		
8. Engine ID Number: EG483	9. Maximum Rated Engine Power: 757 Brake Horsepower (bhp)		
10. Construction Date: October 2013	11. Manufacturer: Generac	12. Model: MD1000 Gemini	13. Model Year: 2013
14. Date of Modification (if applicable):	15. Serial Number (if available):	16. Control Device (if any):	

FUEL DESCRIPTION AND SPECIFICATIONS				
17. Fuel Type	☒ Diesel Fuel (#2) (gal/hr)	☐ Gasoline Fuel (gal/hr)	☐ Natural Gas (cf/hr)	☐ Other Fuels (unit:)
18. Full Load Consumption Rate	31.3			
19. Actual Consumption Rate	28.1			
20. Sulfur Content wt%	0.0015	N/A	N/A	

OPERATING LIMITS & SCHEDULE
21. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.): 500 hours per year
22. Operating Schedule (hours/day, months/year, etc.): 0.5 hours per day for testing and maintenance, testing to occur only during daylight hours

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Engine Information **Form EU1**
Revision 8
1/15/10

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	
Brigham Young University - Idaho	Brigham Young University - Idaho	
3 Brief Project Description:	Replacement of coal-fired boilers with natural gas-fired boilers.	

ENGINE (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

4. Type of Unit:	☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #: Date Issued:		
5. Engine Displacement:	2.69 (liters per cylinder)	6. Ignition Type:	☒ Compression ☐ Spark
7. Use	☒ Emergency ☐ Non-Emergency		

8. Engine ID Number:	9. Maximum Rated Engine Power:		
EG484	757 Brake Horsepower (bhp)		
10. Construction Date:	11. Manufacturer:	12. Model:	13. Model Year:
October 2013	Generac	MD1000 Gemini	2013
14. Date of Modification (if applicable):	15. Serial Number (if available):	16. Control Device (if any):	

FUEL DESCRIPTION AND SPECIFICATIONS

17. Fuel Type	☒ Diesel Fuel (#2) (gal/hr)	☐ Gasoline Fuel (gal/hr)	☐ Natural Gas (cf/hr)	☐ Other Fuels (unit:)
18. Full Load Consumption Rate	31.3			
19. Actual Consumption Rate	28.1			
20. Sulfur Content wt%	0.0015	N/A	N/A	

OPERATING LIMITS & SCHEDULE

21. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):
500 hours per year
22. Operating Schedule (hours/day, months/year, etc.):
0.5 hours per day for testing and maintenance, testing to occur only during daylight hours

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name:	2. Facility Name:	3 Facility ID No:
Brigham Young University - Idaho	Brigham Young University - Idaho	065-00011
4. Brief Project Description:	Replacement of coal-fired boilers with nat. gas-fired boilers and turbine / HRSG.	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request: ☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:

6. Use of Boiler: ☐ % Used For Process ☒ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other: 100%

7. Boiler ID Number: BLR2	8. Rated Capacity: ☒ 55.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: October 2013	10. Manufacturer: TBD	11. Model:
12. Date of Modification (if applicable):	13. Serial Number (if available):	14. Control Device (if any): **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☒ Diesel Fuel (#U) (gal/hr)	☒ Natural Gas (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate	405.5	61,111.1		
17. Actual Consumption Rate	405.5	61,111.1		
18. Fuel Heat Content (Btu/unit, LHV)	135,630	900		
19. Sulfur Content wt%	0.0015	AP-42 Em. Factor		
20. Ash Content wt%	0.01	N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (°F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):		Total fuel for all boilers: NG=1034 million ft3/yr - Diesel = 472 thousand gal/yr
26. Operating Schedule (hours/day, months/year, etc.):		24 hr/day, 12 months/yr, non-curtailment 48 hr/yr ULSD diesel
27. NSPS Applicability: ☒ Yes ☐ No	If Yes, which subpart:	Dc

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name: Brigham Young University - Idaho	2. Facility Name: Brigham Young University - Idaho	3 Facility ID No: 065-00011
4. Brief Project Description:	Replacement of coal-fired boilers with nat. gas-fired boilers and turbine / HRSG.	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request:	☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:	
6. Use of Boiler:	☐ % Used For Process ☒ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other: 100%	
7. Boiler ID Number: BLR3	8. Rated Capacity: ☒ 55.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: October 2013	10. Manufacturer: TBD	11. Model:
12. Date of Modification (if applicable):	13. Serial Number (if available):	14. Control Device (if any): **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☒ Diesel Fuel (#U) (gal/hr)	☒ Natural Gas (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate	405.5	61,111.1		
17. Actual Consumption Rate	405.5	61,111.1		
18. Fuel Heat Content (Btu/unit, LHV)	135,630	900		
19. Sulfur Content wt%	0.0015	AP-42 Em. Factor		
20. Ash Content wt%	0.01	N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^{o}F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):			Total fuel for all boilers: NG=1034 million ft3/yr - Diesel = 472 thousand gal/yr
26. Operating Schedule (hours/day, months/year, etc.):			24 hr/day, 12 months/yr, non-curtailment 48 hr/yr ULSD diesel
27. NSPS Applicability:	☒ Yes ☐ No	If Yes, which subpart:	Dc

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
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Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3 Facility ID No:
Brigham Young University - Idaho	Brigham Young University - Idaho	065-00011
4. Brief Project Description:	Replacement of coal-fired boilers with nat. gas-fired boilers and turbine / HRSG.	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request:	☐ New Unit ☒ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:	
6. Use of Boiler:	☐ % Used For Process ☒ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other: 100%	
7. Boiler ID Number: BLR4	8. Rated Capacity: ☒ 50.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: October 2013	10. Manufacturer: TBD	11. Model:
12. Date of Modification (if applicable):	13. Serial Number (if available):	14. Control Device (if any): **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☒ Diesel Fuel (#U) (gal/hr)	☒ Natural Gas (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate	368.7	55,555		
17. Actual Consumption Rate	368.7	55,555		
18. Fuel Heat Content (Btu/unit, LHV)	135,630	900		
19. Sulfur Content wt%	0.0015	AP-42 Em. Factor		
20. Ash Content wt%	0.01	N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^oF)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):			Total fuel for all boilers: NG=1034 million ft3/yr - Diesel = 472 thousand gal/yr
26. Operating Schedule (hours/day, months/year, etc.):			24 hr/day, 12 months/yr, non-curtailment 48 hr/yr ULSD diesel
27. NSPS Applicability:	☒ Yes ☐ No	If Yes, which subpart:	Dc

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3 Facility ID No:
Brigham Young University - Idaho	Brigham Young University - Idaho	065-00011
4. Brief Project Description:	Replacement of coal-fired boilers with nat. gas-fired boilers and turbine / HRSG.	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request: ☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:

6. Use of Boiler: ☐ % Used For Process ☒ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other: 100%

7. Boiler ID Number: EU01A (HRSG)	8. Rated Capacity: ☒ 30.0 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: TBD	10. Manufacturer: TBD	11. Model:
12. Date of Modification (if applicable):	13. Serial Number (if available):	14. Control Device (if any): **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#U) (gal/hr)	☒ Natural Gas (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		33,333		
17. Actual Consumption Rate		33,333		
18. Fuel Heat Content (Btu/unit, LHV)		900		
19. Sulfur Content wt%		AP-42 Em. Factor		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^oF)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):	Total fuel for all boilers: NG= 1034 million ft3/yr
26. Operating Schedule (hours/day, months/year, etc.):	24 hr/day, 12 months/yr
27. NSPS Applicability: ☒ Yes ☐ No — If Yes, which subpart:	KKKK

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION
Revision 3
4/5/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Brigham Young University - Idaho
Facility Name:	Brigham Young University - Idaho
Facility ID No.:	065-00011
Brief Project Description:	Boiler Replacement

BUILDING AND STRUCTURE INFORMATION

1.	2.	3.	4.	5.	6.	7.
Building ID Number	**Length (ft)**	**Width (ft)**	**Base Elevation (m)**	**Building Height (m)**	**Number of Tiers**	**Description/Comments**
HTPLNT1	33.10	15.60	1492.72	10.16	1	Rectangular Building
HTPLNT2	23.70	4.90	1492.72	3.05	1	Rectangular Building
HTPLNT4	13.30	16.00	1492.72	7.11	1	Rectangular Building
HTPLNT6	23.50	4.90	1492.72	3.05	1	Rectangular Building
AUSTIN	N/A	N/A	1501.47	8.53	1	Polygonal Building
PHYSICAL	N/A	N/A	1495.39	7.32	1	Polygonal Building
BIBBULPH	N/A	N/A	1496.22	8.84	1	Polygonal Building
RIGBY	N/A	N/A	1498.09	8.84	1	Polygonal Building
PHYSPLT	N/A	N/A	1494.92	7.32	1	Polygonal Building
HART	N/A	N/A	1484.17	17.98	1	Polygonal Building
TAYLOR	N/A	N/A	1502.27	7.62	1	Polygonal Building
KIMBALL	N/A	N/A	1507.67	9.45	1	Polygonal Building
KIMGNBLD	N/A	N/A	1512.57	3.35	1	Polygonal Building
MANWAR	N/A	N/A	1497.74	14.23	1	Polygonal Building
SNOWCTR	N/A	N/A	1485.16	9.45	1	Polygonal Building
SPORIB	N/A	N/A	1489.67	21.34	1	Polygonal Building
KIRKHAM	N/A	N/A	1491.60	8.53	1	Polygonal Building
CLARKB	N/A	N/A	1495.40	9.14	1	Polygonal Building
LIBRARY	N/A	N/A	1494.78	14.33	1	Polygonal Building
SMITHA	N/A	N/A	1499.28	19.51	1	Polygonal Building
SMITHB	N/A	N/A	1501.20	13.72	1	Polygonal Building
RADGRA	N/A	N/A	1516.46	7.62	1	Polygonal Building
BENSEN	N/A	N/A	1512.91	4.57	1	Polygonal Building
AUXSER	N/A	N/A	1517.75	7.01	1	Polygonal Building

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION

Revision 3
4/5/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Brigham Young University - Idaho
Facility Name:	Brigham Young University - Idaho
Facility ID No.:	065-00011
Brief Project Description:	Boiler Replacement

BUILDING AND STRUCTURE INFORMATION

1.	2.	3.	4.	5.	6.	7.
Building ID Number	**Length (ft)**	**Width (ft)**	**Base Elevation (m)**	**Building Height (m)**	**Number of Tiers**	**Description/Comments**
ROMNB	N/A	N/A	1491.77	10.67	1	Polygonal Building
BENSADD	N/A	N/A	1514.47	5.18	1	Polygonal Building
RICKSB	N/A	N/A	1518.71	15.24	1	Polygonal Building
AUD1	N/A	N/A	1487.95	25.91	1	Polygonal Building
AUD2	N/A	N/A	1485.70	12.50	1	Polygonal Building
AUD3	N/A	N/A	1491.47	9.45	1	Polygonal Building
AUD4	N/A	N/A	1494.27	20.12	1	Polygonal Building
GYM1	N/A	N/A	1495.61	17.07	1	Polygonal Building
GYM2	N/A	N/A	1494.89	6.40	1	Polygonal Building
HEALTH	N/A	N/A	1519.57	11.58	1	Polygonal Building
ENGINER	N/A	N/A	1519.16	8.84	1	Polygonal Building
LIBRARYA	N/A	N/A	1494.69	9.14	1	Polygonal Building
ENGINA	N/A	N/A	1521.35	4.88	1	Polygonal Building
AUSTIN2	N/A	N/A	1503.42	6.40	1	Polygonal Building
SNOWNO	N/A	N/A	1485.37	8.84	1	Polygonal Building
SNOWNW	N/A	N/A	1484.94	20.42	1	Polygonal Building
SNOWSW	N/A	N/A	1485.44	8.84	1	Polygonal Building
SNOWSE	N/A	N/A	1487.72	4.88	1	Polygonal Building
KIRKSW	N/A	N/A	1491.18	5.03	1	Polygonal Building
KIRKNW	N/A	N/A	1489.19	5.49	1	Polygonal Building
HARTSO	N/A	N/A	1484.55	7.62	1	Polygonal Building
HARTNO	N/A	N/A	1484.31	15.54	1	Polygonal Building
MANWSENT	N/A	N/A	1499.93	14.23	1	Polygonal Building
MANWNO	N/A	N/A	1496.91	19.71	1	Polygonal Building

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION
Revision 3
4/5/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Brigham Young University - Idaho
Facility Name:	Brigham Young University - Idaho
Facility ID No.:	065-00011
Brief Project Description:	Boiler Replacement

BUILDING AND STRUCTURE INFORMATION

1.	2.	3.	4.	5.	6.	7.
Building ID Number	**Length (ft)**	**Width (ft)**	**Base Elevation (m)**	**Building Height (m)**	**Number of Tiers**	**Description/Comments**
MANWEAST	N/A	N/A	1501.43	11.68	1	Polygonal Building
MANWSE	N/A	N/A	1504.17	9.96	1	Polygonal Building
MANWSO	N/A	N/A	1501.82	17.88	1	Polygonal Building
MANWSW	N/A	N/A	1497.99	8.74	1	Polygonal Building
TAYLORN	N/A	N/A	1503.17	21.34	1	Polygonal Building
HINCKLEY	N/A	N/A	1520.47	17.07	1	Polygonal Building
PERKINSW	N/A	N/A	1501.17	6.10	1	Polygonal Building
PERKINSE	N/A	N/A	1502.77	5.49	1	Polygonal Building
KERRW	N/A	N/A	1504.46	6.10	1	Polygonal Building
KEERE	N/A	N/A	1505.94	5.49	1	Polygonal Building
BARNESW	N/A	N/A	1507.82	6.10	1	Polygonal Building
BARNESE	N/A	N/A	1509.41	5.49	1	Polygonal Building
CHAPMAN	N/A	N/A	1507.25	6.10	1	Polygonal Building
LAMPRECH	N/A	N/A	1509.43	6.10	1	Polygonal Building
RICKSW	N/A	N/A	1512.15	6.10	1	Polygonal Building
RICKSE	N/A	N/A	1513.81	5.49	1	Polygonal Building
HTPLNT5	N/A	N/A	1492.72	13.72	1	Polygonal Building

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

AIR PERMIT APPLICATION

Revision 6
10/7/09

For each box in the table below, CTRL+click on the blue underlined text for instructions and information.

IDENTIFICATION	
1. Company Name: Brigham Young University - Idaho	2. Facility Name: Brigham Young Universtiy - Idaho
3. Brief Project Description:	Replacement of coal-fired boilers with natural gas-fired boilers.

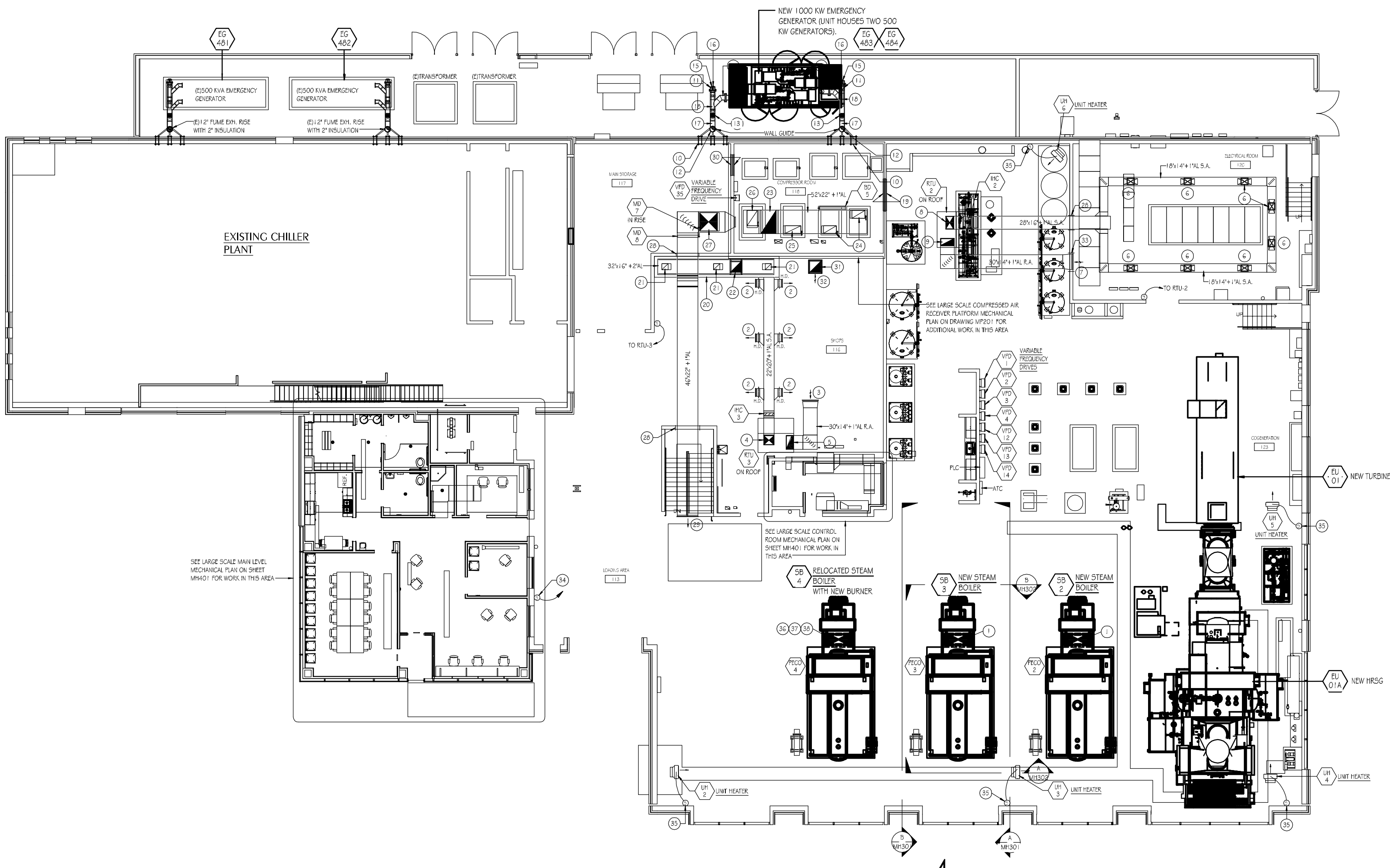
APPLICABILITY DETERMINATION	
4. List applicable subparts of the New Source Performance Standards (NSPS) (40 CFR part 60). Examples of NSPS affected emissions units include internal combustion engines, boilers, turbines, etc. The applicant must thoroughly review the list of affected emissions units.	List of applicable subpart(s): Dc, IIII, KKKK ☐ Not Applicable
5. List applicable subpart(s) of the National Emission Standards for Hazardous Air Pollutants (NESHAP) found in 40 CFR part 61 and 40 CFR part 63. Examples of affected emission units include solvent cleaning operations, industrial cooling towers, paint stripping and miscellaneous surface coating. EPA has a web page dedicated to NESHAP that should be useful to applicants.	List of applicable subpart(s): ☑ Not Applicable
6. For each subpart identified above, conduct a complete a regulatory analysis using the instructions and referencing the example provided on the following pages. **Note** - Regulatory reviews must be submitted with sufficient detail so that DEQ can verify applicability and document in legal terms why the regulation applies. Regulatory reviews that are submitted with insufficient detail will be determined incomplete.	☑ A detailed regulatory review is provided (Follow instructions and example). ☐ DEQ has already been provided a detailed regulatory review. Give a reference to the document including the date.

IF YOU ARE UNSURE HOW TO ANSWER ANY OF THESE QUESTIONS, CALL THE AIR PERMIT HOTLINE AT 1-877-5PERMIT

It is emphasized that it is the applicant's responsibility to satisfy all technical and regulatory requirements, and that DEQ will help the applicant understand what those requirements are prior to the application being submitted but that DEQ will not perform the required technical or regulatory analysis on the applicant's behalf.

ATTACHMENT 3

Central Energy Facility Drawings
(See Tab 14 for Plot Plan)



MAIN LEVEL MECHANICAL PLAN - ELEV. 100'

10 5 0 10 20

DRAWING NOTES

37		DROP 48"x24" COMBUSTION AIR DUCT DOWN FROM THE UPPER MAIN LEVEL AND TRANSITION AND CONNECT TO ROTATED INLET OF EXISTING COMBUSTION AIR FAN ON BURNER. PROVIDE FLEXIBLE CONNECTION AND SEAL AIR TIGHT, SEE SHEET MH102 FOR CONTINUATION. ALL AS PART OF BASE BID.
38		DROP 48"x24" COMBUSTION AIR DUCT DOWN FROM THE UPPER MAIN LEVEL AND TRANSITION AND CONNECT TO INLET OF COMBUSTION AIR FAN ON BURNER. PROVIDE FLEXIBLE CONNECTION AND SEAL AIR TIGHT, SEE SHEET MH102 FOR CONTINUATION. ALL AS PART OF ALTERNATE #1 OR ALTERNATE #2.
39		DROP 48"x24" COMBUSTION AIR DUCT DOWN FROM THE UPPER MAIN LEVEL AND TRANSITION AND CONNECT TO INLET OF COMBUSTION AIR FAN ON BURNER. PROVIDE FLEXIBLE CONNECTION AND SEAL AIR TIGHT, SEE SHEET MH102 FOR CONTINUATION. ALL AS PART OF ALTERNATE #3.

32		TRANSITION FROM 30"x30" EXHAUST AIR GRILLE TO A 26"x26" EXHAUST DUCT AND RISE UP AND TRANSITION AND CONNECT TO REF-6 ON ROOF, SEE SHEET MH102 FOR CONTINUATION.
33		SLEEVE AND SEAL DUCT THROUGH WALL AIR TIGHT. TRIM ONE SIDE WITH DIFFUSER OR GRILLE AND OTHER SIDE WITH ESCUTCHEON.
34		WALL SENSOR FOR UNIT HEATER UH-1 LOCATED HIGH IN LOADING AREA, SEE SHEET MH102 FOR UNIT HEATER LCOATION.
35		WALL SENSOR FOR UNIT HEATER.
36		UNBOLT EXISTING COMBUSTION AIR FAN INLET, ROTATE 90° TO ALLOW COMBUSTION AIR DUCT FROM ABOVE TO CONNECT ON TOP OF FAN AND REBOLT COMBUSTION AIR FAN INLET ON EXISTING BURNER, PROVIDE NEW GASKET AND SEAL AIR TIGHT. ALL AS PART OF BASE BID IN RELOCATING EXISTING BOILER.

25		36"x18" DUCT WITH FLEX CONNECTION BETWEEN AIR COMPRESSOR CABINET AND 52"x22"+1"AL EXHAUST AIR DUCT. FIELD VERIFY INTERCONNECTING DUCT AND MATCH CABINET SIZE.
26		36"x24" DUCT WITH FLEX CONNECTION BETWEEN AIR COMPRESSOR CABINET AND 52"x22"+1"AL EXHAUST AIR DUCT. FIELD VERIFY INTERCONNECTING DUCT AND MATCH CABINET SIZE.
27		RISE 42"x42" DUCT UP TO GRAVITY ROOF VENT. PROVIDE MOTORIZED DAMPER MD-7 IN RISE, SEE DETAIL 6 / MH502.
28		SLEEVE AND SEAL DUCT THROUGH WALL AIR TIGHT. TRIM BOTH SIDES WITH ESCUTCHEON.
29	S-3	10,000 CFM, 48"x24" NECK SUPPLY AIR DIFFUSER. LOCATE DIFFUSER FLUSH WITH WALL BEYOND, LOOKING SOUTH.
30	T-1	2500 CFM, 48"x24" TRANSFER AIR GRILLE HIGH ON WALL, BOTH SIDES.
31	E-2	3,000 CFM, 30"x30" EXHAUST AIR GRILLE.

19	T-1	7500 CFM, 72"x48" TRANSFER AIR GRILLE ABOVE DOOR, BOTH SIDES.
20		24'-0" x 4'-0" x 3'-0" HIGH GALVANIZED SHEET METAL HOOD, SEE DETAIL 2/MH502.
21		14"x14" EXHAUST DUCT CONNECTION TYPICAL OF 3 UP TO COMMON 32"x16"+2"AL EXHAUST AIR DUCT. CONNECT RISER TO COMMON DUCT WITH 45 DEGREE FITTING IN THE DIRECTION OF AIR FLOW.
22		RISE 22"x22"+2"AL EXHAUST AIR DUCT UP AND TRANSITION AND CONNECT TO REF-7 ON ROOF, SEE SHEET MH102 FOR CONTINUATION.
23		RISE 52"x34"+1"AL EXHAUST AIR DUCT UP TO CABINET EXHAUST FAN CEF-1 LOCATED ABOVE AT THE 112' LEVEL OF THE COMPRESSOR ROOM, SEE SHEET MP201 FOR CONTINUATION.
24		30"x18" DUCT WITH FLEX CONNECTION BETWEEN AIR COMPRESSOR CABINET AND 52"x22"+1"AL EXHAUST AIR DUCT. FIELD VERIFY INTERCONNECTING DUCT AND MATCH CABINET SIZE.

8		TRANSITION FROM THE SUPPLY AIR OPENING ON RTU-2 TO A 28"x16"+1"AL SUPPLY AIR DUCT AND DROP DUCT DOWN THROUGH THE ROOF TO SERVE MAIN LEVEL, SEE SHEET MH102 FOR CONTINUATION.
9		RISE 30"x14"+1"AL RETURN AIR DUCT UP THROUGH THE ROOF AND TRANSITION AND CONNECT TO RTU-2 RETURN AIR OPENING, SEE SHEET MH102 FOR CONTINUATION.
10		PRIMARY SUPPORT WITH 12"x12"x3/8" PLATE AND 1/2" BOLTS, TYPICAL.
11		10"Ø FUME EXHAUST DUCT WITH 2" INSULATION AND EXTERIOR JACKET (14" O.D.).
12		12"Ø FUME EXHAUST DUCT WITH 2" INSULATION AND EXTERIOR JACKET (16" O.D.).
13		CUSTOM SIZE LINED BELLOWS JOINT WITH JACKET.
14		10"Ø EXHAUST DUCT WITH 2" INSULATION.
15		10" RELIEF VALVE.
16		6" CHANNEL SUPPORT.
17		12"x10" WYE FITTING.
18		10"x10" WYE FITTING.

1		DROP 48"x24" COMBUSTION AIR DUCT DOWN FROM THE UPPER MAIN LEVEL AND TRANSITION AND CONNECT TO INLET OF COMBUSTION AIR FAN ON BURNER. PROVIDE FLEXIBLE CONNECTION AND SEAL AIR TIGHT, SEE SHEET MH102 FOR CONTINUATION.
2	S-3	415 CFM, 18"x18" NECK SIDEWALL SUPPLY AIR DIFFUSER.
3	R-2	2490 CFM, 36"x28" NECK SIDEWALL RETURN AIR GRILLE.
4		TRANSITION FROM THE SUPPLY AIR OPENING ON RTU-3 TO A 22"x20"+1"AL SUPPLY AIR DUCT AND DROP DUCT DOWN THROUGH THE ROOF TO SERVE MAIN LEVEL, SEE SHEET MH102 FOR CONTINUATION.
5		RISE 30"x14"+1"AL RETURN AIR DUCT UP THROUGH THE ROOF AND TRANSITION AND CONNECT TO RTU-3 RETURN AIR OPENING, SEE SHEET MH102 FOR CONTINUATION.
6	S-3	310 CFM, 16"x14" NECK SIDEWALL SUPPLY AIR DIFFUSER.
7	R-2	2480 CFM, 36"x28" SIDEWALL RETURN AIR GRILLE.

HEATH
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BYU - IDAHO
CENTRAL ENERGY FACILITY ADDITION AND UPGRADES
525 South Center St. - Rexburg, Idaho 83460

STAMP

REGISTERED PROFESSIONAL ENGINEER 4765 STATE OF IDAHO LARRY D. VEIGEL

REVISIONS

HEATH PROJECT NO:	10030
CHECKED BY:	L. VEIGEL
DRAWN BY:	S. TERRY
DATE:	JULY 3, 2013

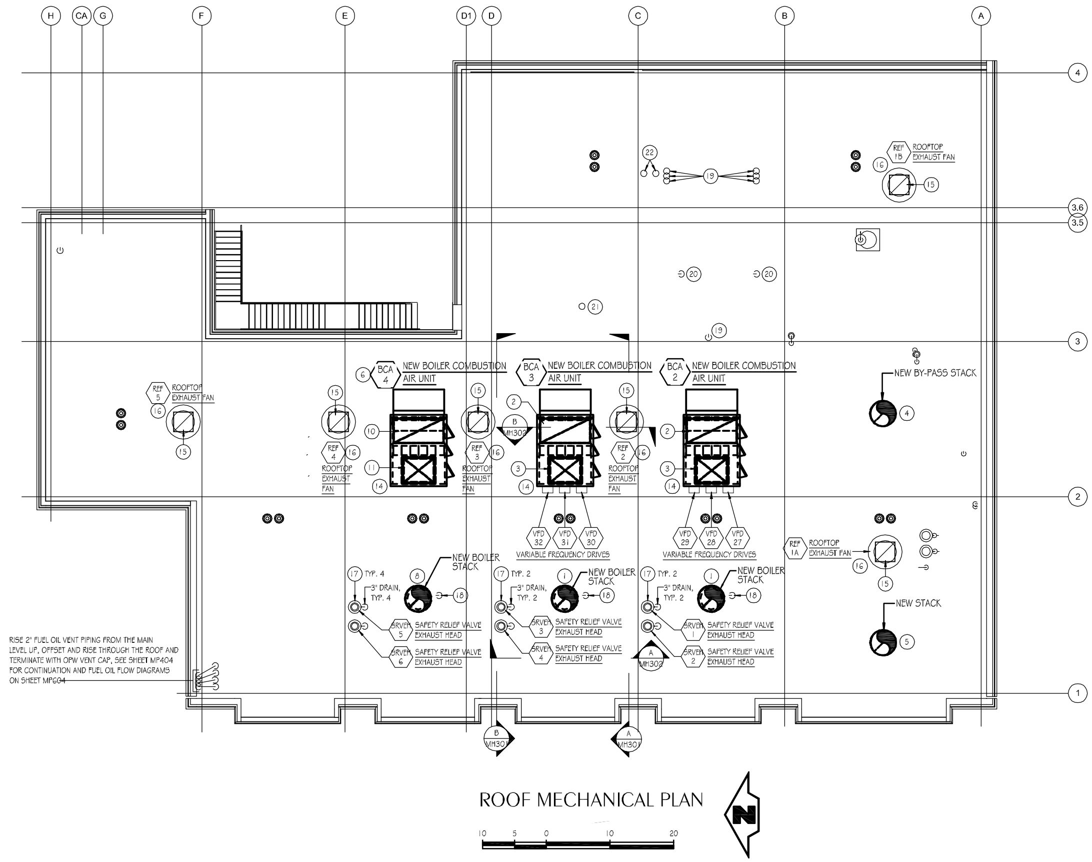
CONSTRUCTION DOCUMENTS

SHEET DESCRIPTION

MAIN LEVEL MECHANICAL PLAN - ELEV. 100'

SHEET NUMBER

MH101



ROOF MECHANICAL PLAN

DRAWING NOTES

1	RISE 49" O.D. / 40" I.D. BOILER STACK FROM BOILER BELOW UP THROUGH ROOF, SEE SHEET MH102 FOR CONTINUATION. RISE STACK UP AND TERMINATE AT 40'-0" ABOVE ROOF.
2	RISE 84"x42" RETURN AIR DUCT FROM EXHAUST GRILLE JUST BELOW THE ROOF DECK UP THROUGH ROOF AND TRANSITION AND CONNECT TO THE COMBUSTION AIR UNIT, SEE SHEET MH102 FOR CONTINAUTION.
3	DROP 44"x44+2"AL COMBUSTION AIR DUCT FROM THE COMBUSTION AIR UNIT DOWN THROUGH ROOF, SEE SHEET MH102 FOR CONTINUATION.
4	54"Ø I.D. / 63" O.D. EXHAUST BYPASS STACK, SEE CGM DRAWINGS.
5	48"Ø I.D. / 57" O.D. EXHAUST HRSG STACK, SEE CGM DRAWINGS.
6	COMBUSTION AIR UNIT BCA-4 IS PART OF BASE BID AND TO BE INSTALLED IF THE EXISTING BOILER IS RELOCATED AS PART OF BASE BID OR ALTERNATE #1 OR IF A NEW BOILER IS INSTALLED AS PART OF ALTERNATE #2.
7	COMBUSTION AIR UNIT BCA-5 IS PART OF ALTERNATE #3.
8	RISE 49" O.D. / 40" I.D. BOILER STACK FROM BOILER BELOW UP THROUGH ROOF, SEE SHEET MH102 FOR CONTINUATION. RISE STACK UP AND TERMINATE AT 40'-0" ABOVE ROOF. THIS STACK IS PART OF BASE BID AND TO BE INSTALLED IF THE EXISTING BOILER IS RELOCATED AS PART OF BASE BID OR ALTERNATE #1 OR IF A NEW BOILER IS INSTALLED AS PART OF ALTERNATE #2.
9	RISE 49" O.D. / 40" I.D. BOILER STACK FROM BOILER BELOW UP THROUGH ROOF, SEE SHEET MH102 FOR CONTINUATION. RISE STACK UP AND TERMINATE AT 40'-0" ABOVE ROOF. THIS STACK IS PART OF ALTERNATE #3.
10	RISE 84"x42" RETURN AIR DUCT FROM EXHAUST GRILLE JUST BELOW THE ROOF DECK UP THROUGH ROOF AND TRANSITION AND CONNECT TO THE COMBUSTION AIR UNIT, SEE SHEET MH102 FOR CONTINUATION. THIS DUCT IS PART OF BASE BID AND TO BE INSTALLED IF THE EXISTING BOILER IS RELOCATED AS PART OF BASE BID OR ALTERNATE #1 OR IF A NEW BOILER IS INSTALLED AS PART OF ALTERNATE #2.
11	DROP 44"x44+2"AL COMBUSTION AIR DUCT FROM THE COMBUSTION AIR UNIT DOWN THROUGH ROOF, SEE SHEET MH102 FOR CONTINUATION. THIS DUCT IS PART OF BASE BID AND TO BE INSTALLED IF THE EXISTING BOILER IS RELOCATED AS PART OF BASE BID OR ALTERNATE #1 OR IF A NEW BOILER IS INSTALLED AS PART OF ALTERNATE #2.
12	RISE 84"x42" RETURN AIR DUCT FROM EXHAUST GRILLE JUST BELOW THE ROOF DECK UP THROUGH ROOF AND TRANSITION AND CONNECT TO THE COMBUSTION AIR UNIT, SEE SHEET MH102 FOR CONTINUATION. THIS DUCT IS PART OF ALTERNATE #3.
13	DROP 44"x44+2"AL COMBUSTION AIR DUCT FROM THE COMBUSTION AIR UNIT DOWN THROUGH ROOF, SEE SHEET MH102 FOR CONTINUATION. THIS DUCT IS PART OF ALTERNATE #3.
14	ROOF CURB, SEE DETAIL 6 / MH502.
15	RISE 36"x36" EXHAUST AIR DUCT UP FROM EXHAUST AIR GRILLE BELOW AND TRANSITION AND CONNECT TO ROOFTOP EXHAUST FAN, SEE SHEET MH102 FOR CONTINUATION.
16	SEE ROOFTOP EXHAUST FAN DETAIL 3 / MH502.
17	TRANSITION FROM A 6" VENT TO A 14" VENT IN THE UPPER MAIN LEVEL AND RISE VENT PIPE UP THROUGH ROOF. TERMINATE WITH A SAFETY RELIEF VALVE EXHAUST HEAD, SEE DETAIL 8 / MP501 AND SHEET MP407 FOR CONTINUATION.
18	RISE 1" VENT UP THROUGH ROOF, SEE DETAIL 8 / MP501 AND SHEET MP407 FOR CONTINUATION.
19	RISE 3" VENT UP THROUGH ROOF, SEE DETAIL 8 / MP501 AND SHEET MP409 FOR CONTINUATION.
20	RISE 2" VENT UP THROUGH ROOF, SEE DETAIL 8 / MP501 AND SHEET MP409 FOR CONTINUATION.
21	RISE 14" VENT UP THROUGH ROOF, SEE DETAIL 8 / MP501 AND SHEET MP409 FOR CONTINUATION.
22	RISE 6" VENT UP THROUGH ROOF, SEE DETAIL 8 / MP501 AND SHEET MP409 FOR CONTINUATION.

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525 South Center St. - Rexburg, Idaho 83460

STAMP

REGISTERED PROFESSIONAL ENGINEER 4765 STATE OF IDAHO LARRY D. VEIGEL

REVISIONS

HEATH PROJECT NO:	10030
CHECKED BY:	L. VEIGEL
DRAWN BY:	S. TERRY
DATE:	JULY 3, 2013

SHEET DESCRIPTION:

ROOF MECHANICAL PLAN

SHEET NUMBER

MH103

CONSTRUCTION DOCUMENTS

ATTACHMENT 4

Solar Taurus 60-7901S 4.5 Megawatt Natural Gas/Oil Turbine Manufacturers Predicted Emissions Data

SOLAR TURBINES INCORPORATED   DATE RUN: 29-Oct-13
ENGINE PERFORMANCE CODE REV. 4.9.1.11.3   RUN BY: Lisa M Conley
JOB ID:

NEW EQUIPMENT PREDICTED EMISSION PERFORMANCE
DATA FOR POINT NUMBER 1

Fuel: SD NATURAL GAS   Customer:
Water Injection: NO   Inquiry Number:
Model: TAURUS 60-7901S   GSC   STANDARD   GAS
Emissions Data: REV. 0.1

The following predicted emissions performance is based on the following specific single point:

kW= 5587, %Full Load=100.0, Elev= 4865ft, %RH= 70.0, Temperature= 0.0F

NOX	CO	UHC	
15.00	25.00	25.00	PPMvd at 15% O2
15.45	15.68	8.98	ton/yr
0.060	0.061	0.035	lbm/MMBtu (Fuel LHV)
0.60	0.61	0.35	lbm/(MW-hr) (gas turbine shaft pwr)
3.53	3.58	2.05	lbm/hr

NOTES:

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

SOLAR TURBINES INCORPORATED DATE RUN: 29-Oct-13
ENGINE PERFORMANCE CODE REV. 4.9.1.11.3 RUN BY: Lisa M Conley
JOB ID:

NEW EQUIPMENT PREDICTED EMISSION PERFORMANCE
DATA FOR POINT NUMBER 2

Fuel: SD NATURAL GAS Customer:
Water Injection: NO Inquiry Number:
Model: TAURUS 60-7901S GSC STANDARD GAS
Emissions Data: REV. 0.1

The following predicted emissions performance is based on the following specific single point:

kW= 4693, %Full Load=100.0, Elev= 4865ft, %RH= 60.0, Temperature= 59.0F

NOX	CO	UHC	
15.00	25.00	25.00	PPMvd at 15% O2
13.38	13.58	7.78	ton/yr
0.060	0.061	0.035	lbm/MMBtu (Fuel LHV)
0.61	0.62	0.36	lbm/(MW-hr) (gas turbine shaft pwr)
3.06	3.10	1.78	lbm/hr

NOTES:
1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

SOLAR TURBINES INCORPORATED DATE RUN: 29-Oct-13
ENGINE PERFORMANCE CODE REV. 4.9.1.11.3 RUN BY: Lisa M Conley
JOB ID:

TAURUS 60-7901S
GSC
STANDARD
GAS
TTF-1S REV. 2.1
ES-2091
ES-2091

DATA FOR NOMINAL PERFORMANCE

Fuel Type	SD NATURAL GAS		
Elevation	feet	4865	
Inlet Loss	in H2O	1.5	
Exhaust Loss	in H2O	1.5	
Engine Inlet Temp.	deg F	0	59.0
Relative Humidity	%	70.0	60.0
Elevation Loss	kW	1071	900
Inlet Loss	kW	38	34
Exhaust Loss	kW	15	14
Gearbox Efficiency		0.9800	0.9800
Generator Efficiency		0.9640	0.9640
Based On 1.0 Power Factor			
Specified Load*	kW	FULL	FULL
Net Output Power*	kW	5587	4693
Fuel Flow	mmBtu/hr	58.66	51.16
Heat Rate*	Btu/kW-hr	10500	10901
Therm Eff*	%	32.498	31.301
Inlet Air Flow	lbm/hr	154565	141633
Engine Exhaust Flow	lbm/hr	157009	143747
PCD	psiG	148.6	135.4
Compensated PTIT	deg F	1250	1250
PT Exit Temperature	deg F	925	954
Exhaust Temperature	deg F	925	954

FUEL GAS COMPOSITION (VOLUME PERCENT)
LHV (Btu/Scf) = 939.2 SG = 0.5970 W.I. @60F (Btu/Scf) = 1215.6

Methane (CH4)	= 92.7899
Ethane (C2H6)	= 4.1600
Propane (C3H8)	= 0.8400
N-Butane (C4H10)	= 0.1800
N-Pentane (C5H12)	= 0.0400
Hexane (C6H14)	= 0.0400
Carbon Dioxide (CO2)	= 0.4400
Hydrogen Sulfide (H2S)	= 0.0001
Nitrogen (N2)	= 1.5100

STANDARD CONDITIONS FOR GAS VOLUMES: Temperature: 60 deg F Pressure: 29.92 in Hg
NORMAL CONDITIONS FOR GAS VOLUMES: Temperature: 32 deg F Pressure: 29.92 in Hg

!!! PLEASE, SUBMIT INQUIRY ON GAS FUEL SUITABILITY TO SAN DIEGO !!!

*Electric power measured at the generator terminals.
This performance was calculated with a basic inlet and exhaust system.
Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance.
Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

SOLAR TURBINES INCORPORATED　　DATE RUN: 29-Oct-13
ENGINE PERFORMANCE CODE REV. 4.9.1.11.3　　RUN BY: Lisa M Conley
JOB ID:

NEW EQUIPMENT PREDICTED EMISSION PERFORMANCE
DATA FOR POINT NUMBER 1

Fuel: DIESEL 2-D　　Customer:
Water Injection: NO　　Inquiry Number:
Model: TAURUS 60-7901S GSC STANDARD DUAL
Emissions Data: REV. 1.0

The following predicted emissions performance is based on the following specific single point:

kW= 5483, %Full Load=100.0, Elev= 4865ft, %RH= 70.0, Temperature= 0.0F

NOX	CO	UHC	
65.00	25.00	25.00	PPMvd at 15% O2
67.89	15.90	9.10	ton/yr
0.268	0.063	0.036	lbm/MMBtu (Fuel LHV)
2.67	0.63	0.36	lbm/(MW-hr) (gas turbine shaft pwr)
15.50	3.63	2.08	lbm/hr

NOTES:
1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

SOLAR TURBINES INCORPORATED   DATE RUN: 29-Oct-13
ENGINE PERFORMANCE CODE REV. 4.9.1.11.3   RUN BY: Lisa M Conley
JOB ID:

NEW EQUIPMENT PREDICTED EMISSION PERFORMANCE
DATA FOR POINT NUMBER 2

Fuel: DIESEL 2-D   Customer:
Water Injection: NO   Inquiry Number:
Model: TAURUS 60-7901S   GSC   STANDARD   DUAL
Emissions Data: REV. 1.0

The following predicted emissions performance is based on the following specific single point:

kW= 4590, %Full Load=100.0, Elev= 4865ft, %RH= 60.0, Temperature= 59.0F

NOX	CO	UHC	
65.00	25.00	25.00	PPMvd at 15% O2
58.76	13.76	7.88	ton/yr
0.266	0.062	0.036	lbm/MMBtu (Fuel LHV)
2.76	0.65	0.37	lbm/(MW-hr) (gas turbine shaft pwr)
13.41	3.14	1.80	lbm/hr

NOTES:
1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

SOLAR TURBINES INCORPORATED DATE RUN: 29-Oct-13
ENGINE PERFORMANCE CODE REV. 4.9.1.11.3 RUN BY: Lisa M Conley
JOB ID:

TAURUS 60-7901S
GSC
STANDARD
DUAL
TTF-1S REV. 2.1
ES-2091
ES-2091

DATA FOR NOMINAL PERFORMANCE

*** LIQUID FUEL WITH 65PPM NOX GUARANTEE REQUIRES AN SER PRIOR TO FORMAL QUOTATION ***

*** REFERENCE PIB 156 FOR PURGE REQUIREMENTS ***

*** PER PPB 13-14, PROJECTS WITH DIESEL FUEL SULFUR LEVEL OVER 2000 PPMW (0.2 WT%) OR WHERE NO LIQUID FUEL SPECIFICATION IS AVAILABLE REQUIRE AN APPROVED SER PRIOR TO QUOTING REGARDLESS OF THE PERFORMANCE OR EMISSIONS REQUIREMENTS. FOR PROJECTS SOURCING AVIATION KEROSENE AN SER IS REQUIRED ONLY IF SULFUR EXCEEDS 3000 PPMW (0.3 WT%). ***

Fuel Type		DIESEL 2-D	
Specific Gravity of Fuel		0.850	
Elevation	feet	4865	
Inlet Loss	in H2O	1.5	
Exhaust Loss	in H2O	1.5	
Engine Inlet Temp.	deg F	0	59.0
Relative Humidity	%	70.0	60.0
Elevation Loss	kW	1051	881
Inlet Loss	kW	38	33
Exhaust Loss	kW	14	14
Gearbox Efficiency		0.9800	0.9800
Generator Efficiency		0.9640	0.9640
Based On 1.0 Power Factor			
Specified Load*	kW	FULL	FULL
Net Output Power*	kW	5483	4590
Fuel Flow	mmBtu/hr	57.91	50.48
Heat Rate*	Btu/kW-hr	10561	10997
Therm Eff*	%	32.310	31.027
Inlet Air Flow	lbm/hr	154565	141647
Engine Exhaust Flow	lbm/hr	157314	144025
PCD	psiG	147.9	134.9
Compensated PTIT	deg F	1250	1250
PT Exit Temperature	deg F	925	954
Exhaust Temperature	deg F	925	954

*Electric power measured at the generator terminals.
This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

ATTACHMENT 5

Cleaver Brooks Heat Recovery Steam Generator (HRSG) MF-4(S)-70 with Natcom Burner Manufacturers Emissions Data

BYU IDAHO BOILER INFORMATION

DATA		HRSG
MODEL NUMBER		MF-4(S)-70
MAX HEAT INPUT (MMBTU/HR (HHV))		28.12
MAX PROCESS RATE (MMBTU/HR)		50.2
STEAM FLOW RATE (LBS/HR)		50,000
STACK GAS FLOW RATE (ACFM)		48,289
STACK GAS EXIT TEMP (DEG. F)		254
GUARANTEED EMISSIONS RATES (DUCT BURNER)	UOM	NG
NOX	PPH/TPY	2.81/12.32
CO	PPH/TPY	2.81/12.32
**SEE NOTES BELOW FOR MORE EMISSIONS DETAILS		

****NOTES:**

Guaranteed Emission based on:

- Emissions listed below are for the duct burner only and do not include emissions from the turbine.

- NOx & CO emissions in [lb/MMBtu] are based on HHV and at 100% MCR.

- NOx emissions shall not exceed the NOx in lb/hr at 100% MCR over the burner's turndown.

- CO emissions shall not exceed the CO in lb/hr at 100% MCR over a 4 to 1 burner turndown

- NATCOM technician is required for start-up and adjustments.

- Above emissions are valid for TEG composition, temperature and mass flow rate as defined in this
proposal. Emission guarantees are subject to change for other TEG conditions.

- Emission and capacity guarantees are specific to the fuel analysis listed below.

Above information is preliminary only and will be confirmed on drawings issued for construction.

BYU-Idaho
Boiler/Burner Emissions Data

A) Packaged Burners (Boilers)

Fuel	Natural Gas	Oil #2
	lb/MMBTU	lb/MMBTU
PMTOTAL	0.0075	0.03
PM10	0.0075	0.015
PM2.5	0.0075	0.0036

B) Duct Burner (HRSG)

Fuel	Natural Gas	
	lb/MMBTU	
PMTOTAL	0.01	
PM10	0.009	
PM2.5	0.008	

From e-mail 4 Nov 2013…
Please note that the total PM emissions guarantee for NG firing for the packaged burners has been lowered to match the EPA emissions factors table.

Let us know if you require additional information.

Regards,

Greg Kaup
Sales Manager - ERI
Engineered Boiler Systems
[cid:CB_logo_SeeVideo.jpg]<http://player.vimeo.com/external/31611334.sd.mp4?s=a5202f7489923fbd75bfd9253cbf23cd>

ATTACHMENT 6

Cleaver Brooks Steam Boilers NOS-2-54
With Natcom Burner P-64-LOG-23-117
Manufacturers Emissions Data

BYU IDAHO BOILER INFORMATION

DATA	IWT - O STYLE		
MODEL NUMBER	NOS-2-54		
MAX HEAT INPUT (MMBTU/HR (HHV))	53.9		
MAX PROCESS RATE (MMBTU/HR)	53.9		
STEAM FLOW RATE (LBS/HR)	45,000		
STACK GAS FLOW RATE (ACFM)	15,255		
STACK GAS EXIT TEMP (DEG. F) W/ECON	317		
GUARANTEED EMISSIONS RATES	UOM	NG	#2 OIL
NOX	PPH/TPY	1.9404/8.498952	5.2734/23.09749
CO	PPH/TPY	2.156/9.44328	2.0163/8.831394
CSOX	LB/MMBTU	NEGLIGIBLE	0.205
PM (PARTICULATE)	LB/MMBTU	0.01	0.03
VOC	LB/MMBTU	0.004	0.004
**SEE NOTES BELOW FOR MORE EMISSIONS DETAILS			

NOTES:

Emissions based on from 25% to 100% MCR corrected to 3% O2 on a dry basis. NATCOM technician is required for startup and adjustments. PM is esclusive of any particulates in combustion air or other sources of residual particulates from material.

BYU-Idaho
Boiler/Burner Emissions Data

A) Packaged Burners (Boilers)

Fuel	Natural Gas	Oil #2
	lb/MMBTU	lb/MMBTU
PMTOTAL	0.0075	0.03
PM10	0.0075	0.015
PM2.5	0.0075	0.0036

B) Duct Burner (HRSG)

Fuel	Natural Gas	
	lb/MMBTU	
PMTOTAL	0.01	
PM10	0.009	
PM2.5	0.008	

From e-mail 4 Nov 2013…
Please note that the total PM emissions guarantee for NG firing for the packaged burners has been lowered to match the EPA emissions factors table.

Let us know if you require additional information.

Regards,

Greg Kaup
Sales Manager - ERI
Engineered Boiler Systems
[cid:CB_logo_SeeVideo.jpg]<http://player.vimeo.com/external/31611334.sd.mp4?s=a5202f7489923fbd75bfd9253cbf23cd>

ATTACHMENT 7

Existing Indec Steam Boiler
With New Natcom Burner P-50-LOG-23-117
Manufacturers Emissions Data

BYU IDAHO BOILER INFORMATION

DATA	RETROFIT NATCOM BURNER		
MODEL NUMBER	NATCOM P-50-LOG-23-1117		
MAX HEAT INPUT (MMBTU/HR (HHV))	50		
MAX PROCESS RATE (MMBTU/HR)	**PER INDECK/VOLCANO**		
STEAM FLOW RATE (LBS/HR)	40,000 - RATED DESIGN		
STACK GAS FLOW RATE (ACFM)	**PER INDECK/VOLCANO**		
STACK GAS EXIT TEMP (DEG. F) W/ECON	**PER INDECK/VOLCANO**		
GUARANTEED EMISSIONS RATES	UOM	NG	#2 OIL
NOX	PPH/TPY	1.80/7.88	4.90/21.44
CO	PPH/TPY	2.00/8.76	1.87/8.20
SOX	LB/MMBTU	NEGLIGIBLE	0.21
PM (PARTICULATE)	LB/MMBTU	0.01	0.03
VOC	LB/MMBTU	0.004	0.004
****SEE NOTES BELOW FOR MORE EMISSIONS DETAILS**			

****NOTES:**

Emissions based on from 25% to 100% MCR corrected to 3% O2 on a dry basis. NATCOM technician is required for startup and adjustments. PM is esclusive of any particulates in combustion air or other sources of residual particulates from material. Performance and Emissions Guarantess are based on assumbed boiler criteria and will be revised once acutal existing boielr parameters are submitted.

BYU-Idaho
Boiler/Burner Emissions Data

A) Packaged Burners (Boilers)

Fuel	Natural Gas	Oil #2
	lb/MMBTU	lb/MMBTU
PMTOTAL	0.0075	0.03
PM10	0.0075	0.015
PM2.5	0.0075	0.0036

B) Duct Burner (HRSG)

Fuel	Natural Gas	
	lb/MMBTU	
PMTOTAL	0.01	
PM10	0.009	
PM2.5	0.008	

From e-mail 4 Nov 2013…
Please note that the total PM emissions guarantee for NG firing for the packaged burners has been lowered to match the EPA emissions factors table.

Let us know if you require additional information.

Regards,

Greg Kaup
Sales Manager - ERI
Engineered Boiler Systems
[cid:CB_logo_SeeVideo.jpg]<http://player.vimeo.com/external/31611334.sd.mp4?s=a5202f7489923fbd75bfd9253cbf23cd>

ATTACHMENT 8

New Generac MD1000CEM Diesel Generator
Specifications and Emissions Information
Existing Generac MD500 MPS Diesel Generators

GENERAC® INDUSTRIAL POWER

MD1000GEM

Industrial Diesel Generator Set

EPA Certified Stationary Emergency

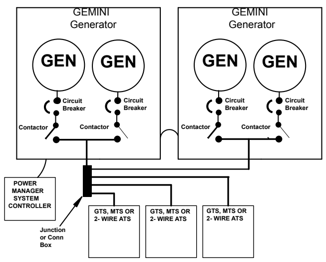
PARALLELING UNIT

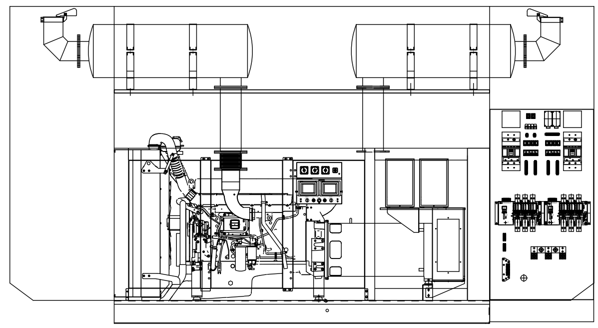
Standby Power Rating

1250kVA 1000KW 60 Hz

Prime Power Rating*

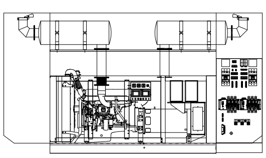
1125kVA 900KW 60 Hz

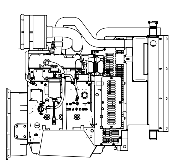


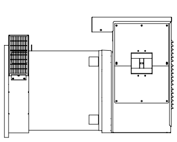


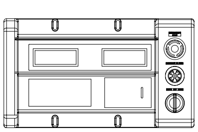
Generator image used for illustration purposes only

*EPA Certified Prime ratings are not available in the U.S. or its Territories for engine model year 2011 and beyond









features / benefits

features	benefits
Generator Set	
CONFIGURED FOR PARALLELING	MODULAR PARALLELING SYSTEM
UL2200 TESTED	ENSURES A QUALITY PRODUCT
RHINOCOAT PAINT SYSTEM	IMPROVES RESISTANCE TO ELEMENTS
ACOUSTIC ENCLOSURE STANDARD	PROVIDES A SINGLE SOURCE SOLUTION
Engines	
EPA COMPLIANT	ENVIRONMENTALLY FRIENDLY
INDUSTRIAL TESTED, GENERAC APPROVED	ENSURES INDUSTRIAL STANDARDS
POWER-MATCHED OUTPUT	ENGINEERED FOR PERFORMANCE
INDUSTRIAL GRADE	IMPROVES LONGEVITY AND RELIABILITY
Alternators	
TWO-THIRDS PITCH	ELIMINATES HARMFUL 3RD HARMONIC
LAYER WOUND ROTOR & STATOR	IMPROVES COOLING
CLASS H MATERIALS	HEAT TOLERANT DESIGN
DIGITAL 3-PHASE VOLTAGE CONTROL	FAST AND ACCURATE RESPONSE
Controls	
INTEGRATED PARALLELING	SINGLE CONTROL MODULE
4-20mA VOLTAGE-TO-CURRENT SENSORS	NOISE RESISTANT 24/7 MONITORING
SURFACE-MOUNT TECHNOLOGY	PROVIDES VIBRATION RESISTANCE
ADVANCED DIAGNOSTICS & COMMUNICATIONS	HARDENED RELIABILITY

primary codes and standards

NEMA c UL us LISTED NFPA ASTM INTERNATIONAL ISO

GENERAC INDUSTRIAL POWER

MD1000

application and engineering data

ENGINE SPECIFICATIONS

General

Make	Generac
EPA Emissions Compliance	Stationary Emergency
EPA Emissions Reference	See Emissions Data Sheet
Cylinder #	(2) 6
Type	In - Line
Displacement - L (cu. in.)	16.12 (983.7)
Bore - mm (in.)	144 (5.67)
Stroke - mm (in.)	165 (6.5)
Compression Ratio	16.5:1
Intake Air Method	Turbocharged/Aftercooled
Cylinder Head Type	One Piece Cast Iron
Piston Type	Aluminum w/ Cooling Cavity, oil cooled
Connecting Rod Type	I-Beam Section

Engine Governing

Governor	Electronic Isochronous
Frequency Regulation (Steady State)	± 0.25%

Lubrication System

Oil Pump Type	Gear
Oil Filter Type	Full - Flow Cartridge
Crankcase Capacity - L (gal)	48 (12.7)

Cooling System (each engine)

Cooling System Type	Closed Recovery
Water Pump	Prelubed, Self Sealing
Fan Type	Pusher
Fan Speed (rpm)	1872
Fan Diameter mm (in.)	889 (35)
Coolant Heater Standard Wattage	2x2000W
Coolant Heater Standard Voltage	240VAC

Fuel System (each engine)

Fuel Type	Ultra Low Sulfur Diesel Fuel
Fuel Specifications	ASTM
Fuel Filtering (microns)	10
Fuel Inject Pump Make	Delphi
Fuel Pump Type	Engine Driven Gear
Injector Type	Multi-hole, Nozzle Type
Engine Type	Direct Injection
Fuel Supply Line - mm (in.)	12.7 (½")
Fuel Return Line - mm (in.)	12.7 (½")

Engine Electrical System (each engine)

System Voltage	24 VDC
Battery Charging Alternator	80 Amps
Battery Size (at 0ºC)	1155
Battery Group	8D
Battery Voltage	(2) - 12 VDC
Ground Polarity	Negative

ALTERNATOR SPECIFICATIONS

Standard Model	Generac WEG
Poles	4
Field Type	Revolving
Insulation Class - Rotor	H
Insulation Class - Stator	H
Total Harmonic Distortion	< 3%
Telephone Interference Factor (TIF)	< 50
Standard Excitation	Self-Ventilated, Drip-Proof
Bearings	Single Sealed Cartridge
Coupling	Direct, Flexible Disc
Load Capacity - Standby	100%
Prototype Short Circuit Test	Yes

Voltage Regulator Type	Digital
Number of Sensed Phases	All
Regulation Accuracy (Steady State)	± 0.25%
Paralleling Controls	Standard

CODES AND STANDARDS COMPLIANCE (WHERE APPLICABLE)

NFPA 99
NFPA 110
ISO 8528-5
ISO 1708A.5
ISO 3046

BS5514
SAE J1349
DIN6271
IEEE C62.41 TESTING
NEMA ICS 1
UL2200

PARALLELING CONTROLS

AUTO-SYNCHRONIZATION PROCESS
ISOCHRONOUS LOAD SHARING
REVERSE POWER PROTECTION
MAXIMUM POWER PROTECTION
ELECTRICALLY OPERATED, MECHANICALLY HELD PARALLELING SWITCH
SYNC CHECK SYSTEM
INDEPENDENT ON-BOARD PARALLELING
OPTIONAL PROGRAMMABLE LOGIC FULL AUTO BACK-UP CONTROL (PLS)

Rating Definitions:
Standby – Applicable for a varying emergency load for the duration of a utility power outage with no overload capability. (Max. load factor = 70%)
Prime – Applicable for supplying power to a varying load in lieu of utility for an unlimited amount of running time. (Max. load factor = 80%) A 10% overload capacity is available for 1 out of every 12 hours.

MD1000 operating data (60Hz)

POWER RATINGS (kW)

	STANDBY		PRIME	
Three-Phase 277/480VAC @0.8pf	1000 kW	Amps: 1505	900 kW	Amps: 1355
Three-Phase 346/600VAC @0.8pf	1000 kW	Amps: 1204	900 kW	Amps: 1084

STARTING CAPABILITIES (sKVA)

sKVA vs. Voltage Dip

		480VAC					
Alternator	kW	10%	15%	20%	25%	30%	35%
Standard	(2) 500	914	1371	1829	2286	2743	3200
Upsize 1	-	-	-	-	-	-	-

FUEL

Fuel Pump Lift - mm (in)
1000 (40)

Fuel Consumption Rates* **(includes two engines)**

STANDBY			PRIME		
Percent Load	gph	lph	Percent Load	gph	lph
25%	17.4	65.8	25%	15.4	56.6
50%	30.6	115.8	50%	26.8	101.4
75%	45.4	171.8	75%	39.8	150.6
100%	62.6	237.0	100%	56.2	212.8

* Refer to "Emissions Data Sheet" for maximum fuel flow for EPA and SCAQMD permitting purposes.

COOLING

Coolant Capacities - Gal (L)

System	(2) x 15.9 (60.2)
Engine	(2) x 8.78 (33)
Radiator	(2) x 7.1 (26.9)

		STANDBY	PRIME
Coolant Flow per Minute	gpm (lpm)	(2) x 122 (462)	(2) x 122 (462)
Heat Rejection to Coolant	BTU/hr	(2) x 1,153,968	(2) x 1,035,991
Inlet Air	cfm (m3/min)	(2) x 23,308 (660)	(2) x 23,308 (660)
Max. Operating Radiator Air Temp	F° (C°)	122 (50)	122 (50)
Max. Operating Ambient Temperature	F° (C°)	104 (40)	104 (40)
Maximum Radiator Backpressure	in H_2O	1.5	1.5

COMBUSTION AIR REQUIREMENTS

		STANDBY	PRIME
Flow at Rated Power	cfm (m3/min)	(2) x 1617 (45.8)	(2) x 1554 (44.0)

ENGINE

		STANDBY	PRIME
Rated Engine Speed	rpm	1800	1800
Horsepower at Rated kW**	hp	757	681
Piston Speed	ft/min	1950	1950
BMEP	psi	339	302

** Refer to "Emissions Data Sheet" for maximum bHP for EPA and SCAQMD permitting purposes.

EXHAUST

		STANDBY	PRIME
Exhaust Flow (Rated Output)	cfm (m^3/min)	(2) x 3899 (110.4)	(2) x 3553 (100.6)
Max. Backpressure (Post Silencer)	inHg (Kpa)	1.5 (5.1)	1.5 (5.1)
Exhaust Temp (Rated Output)	°F (°C)	893 (479)	817 (436)
Exhaust Outlet Size (Open Set)	(2) x 8" Diameter Exhaust Stack		

Deration – Operational characteristics consider maximum ambient conditions. Derate factors may apply under atypical site conditions. Please consult a Generac Power Systems Industrial Dealer for additional details. All performance ratings in accordance with ISO3046, BS5514, ISO8528 and DIN6271 standards.

GENERAC | INDUSTRIAL POWER

MD1000

standard features and options

GENERATOR SET

●	Genset Vibration Isolation	Std
○	IBC Seismic Certified/Seismic Rated Vibration Isolators	Opt
○	Extended warranty	Opt
○	Gen-Link Communications Software	Opt
●	Steel Enclosure	Std
○	Aluminum Enclosure	Opt
○	Enclosure Lighting Kits	Opt

ENGINE SYSTEM

	General	
●	Oil Drain Extensions	Std
○	Oil Make-Up Systems	Opt
○	Oil Heaters	Opt
●	Air cleaners	Std
●	Fan guards	Std
●	Radiator duct adapters	Std
●	Critical Exhaust Silencers	Std

	Fuel System	
●	Fuel lockoff solenoids	Std
●	Secondary fuel filters	Std
●	Stainless steel flexible exhaust connections	Std
○	Primary fuel filters	Opt
○	Single Wall Tank (Export Only)	-
○	UL 142 Fuel Tank	Opt

	Cooling System	
○	208VAC Coolant Heaters	Opt
●	240VAC Coolant Heaters	Std
○	Other Coolant Heaters	-
●	Closed Coolant Recovery Systems	Std
●	UV/Ozone resistant hoses	Std
●	Factory-Installed Radiators	Std
●	Radiator Drain Extensions	Std

	Engine Electrical System	
●	Battery charging alternators	Std
●	Battery cables	Std
○	Battery trays	Opt
○	Battery boxs	Opt
○	Battery heaters	Opt
●	Solenoid activated starter motors	Std
○	10A UL float/equalize battery chargers	Opt
●	Rubber-booted engine electrical connections	Std

ALTERNATOR SYSTEM

●	UL2200 GENprotect™	Std
●	Main Line Circuit Breakers (Output connections on paralleling switch)	Std
○	Anti-Condensation Heaters	Opt
●	Tropical coating	Std
●	Permanent Magnet Excitation	Std

CONTROL SYSTEM

	Control Panel	
○	Digital H Control Panel - Dual 4x20 Display	na
○	Digital G-100 Control Panel - Touchscreen	na
●	Digital G-200 Paralleling Control Panel - Touchscreen	Std
●	Programmable Crank Limiter	Std
○	21-Light Remote Annunciator	Opt
○	Remote Relay Panel (8 or 16)	Opt
●	7-Day Programmable Exerciser	Std
●	Special Applications Programmable PLC	Std
●	RS-232	Std
●	RS-485	Std
●	All-Phase Sensing DVR	Std
●	Full System Status	Std
●	Utility Monitoring (Req. H-Transfer Switch)	Std
●	2-Wire Start Compatible	Std
●	Power Output (kW)	Std
●	Power Factor	Std
●	Reactive Power	Std
●	All phase AC Voltage	Std
●	All phase Currents	Std
●	Oil Pressure	Std
●	Coolant Temperature	Std
●	Coolant Level	Std
○	Oil Temperature	Opt
●	Fuel Pressure	Std
●	Engine Speed	Std
●	Battery Voltage	Std
●	Frequency	Std
●	Date/Time Fault History (Event Log)	Std
○	Low-Speed Exercise	-
●	Isochronous Governor Control	Std
●	-40deg C - 70deg C Operation	Std
●	Waterproof Plug-In Connectors	Std
●	Audible Alarms and Shutdowns	Std
●	Not in Auto (Flashing Light)	Std
●	Auto/Off/Manual Switch	Std
●	E-Stop (Red Mushroom-Type)	Std
○	Remote E-Stop (Break Glass-Type, Surface Mount)	Opt
○	Remote E-Stop (Red Mushroom-Type, Surface Mount)	Opt
○	Remote E-Stop (Red Mushroom-Type, Flush Mount)	Opt
●	NFPA 110 Level I and II (Programmable)	Std
●	Remote Communication - RS232	Std
○	Remote Communication - Modem	Opt
○	Remote Communication - Ethernet	Opt
○	PLS Full Auto Back-Up for PM-SC	Opt

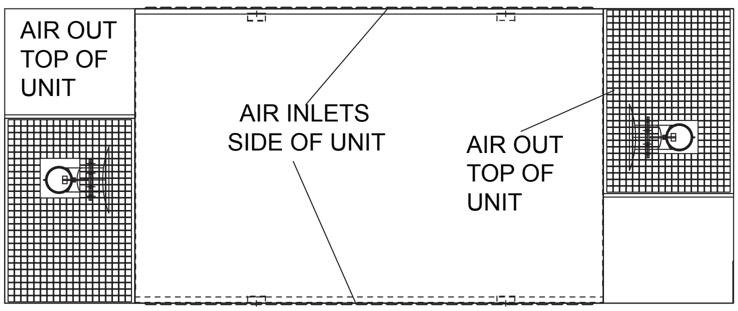
	Alarms (Programmable Tolerances, Pre-Alarms and Shutdowns)	
○	Low Fuel	Opt
●	Oil Pressure (Pre-programmed Low Pressure Shutdown)	Std
●	Coolant Temperature (Pre-programmed High Temp Shutdown)	Std
●	Coolant Level (Pre-programmed Low Level Shutdown)	Std
●	Oil Temperature	Std
●	Engine Speed (Pre-programmed Overspeed Shutdown)	Std
●	Voltage (Pre-programmed Overvoltage Shutdown)	Std
●	Battery Voltage	Std

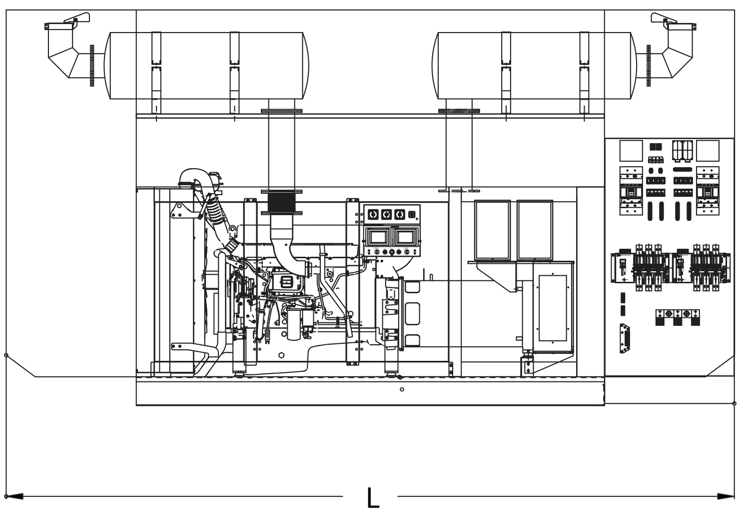
MD1000

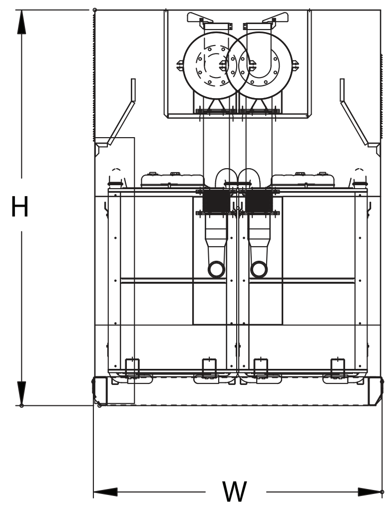
dimensions, weights and sound levels

LEVEL 1 ACOUSTIC ENCLOSURE

RUN TIME HOURS	USABLE CAPACITY (GAL)	L	W	H	WT	dBA*
NO TANK	-	258	96	131	21000	80
14	853	258	96	151	25130	
25	1578	258	96	160	25630	
37	2310	258	96	170	26370	







*All measurements are approximate and for estimation purposes only. Weights are without fuel in tank. Sound levels measured at 23ft (7m) and does not account for ambient site conditions.

Tank Options

	Option	
○	MDEQ	OPT
○	Florida DERM/DEP	OPT
○	Chicago Fire Code	OPT
○	IFC Certification	CALL
○	ULC	CALL

Other Custom Options Available from your Generac Industrial Power Dealer

YOUR FACTORY RECOGNIZED GENERAC INDUSTRIAL DEALER

Specification characteristics may change without notice. Dimensions and weights are for preliminary purposes only. Please consult a Generac Power Systems Industrial Dealer for detailed installation drawings.

GENERAC | INDUSTRIAL POWER

CERTIFICATION DATA

EXHAUST EMISSIONS DATA

STATEMENT OF EXHAUST EMISSIONS
2013 VOLVO DIESEL FUELED GENERATOR

The measured emissions values provided here are proprietary to Generac and it's authorized dealers. This information may only be disseminated upon request, to regulatory governmental bodies for emissions permitting purposes or to specifying organizations as submittal data when expressly required by project specifications, and shall remain confidential and not open to public viewing. This information is not intended for compilation or sales purposes and may not be used as such, nor may it be reproduced without the expressed written permission of Generac Power Systems, Inc. The data provided shall not be meant to include information made public by Generac.

Generator Model:	**MD1000 Gemini****	EPA Certificate Number:	**DVPXL16.1ACB-003**
kW_e Rating:	**1000**	CARB Certificate Number:	**Not Applicable**
Engine Family:	**DVPXL16.1ACB**	SCAQMD CEP Number:	**442149**
Engine Model:	**TAD1641GE**	Emission Standard Category:	**Tier 2**
Rated Engine Power (BHP)*:	**757**	Certification Type:	**Stationary Emergency CI (40 CFR Part 60 Subpart IIII)**
Fuel Consumption (gal/hr)*:	**31.3**		
Aspiration:	**Turbo/Aftercooled**		
Rated RPM:	**1800**		

*Engine Power and Fuel Consumption are declared by the Engine Manufacturer of Record and the U.S. EPA.
**Two engines per Gemini genset package. All data is per engine.

Emissions based on engine power of specific Engine Model.
(These values are actual composite weighted exhaust emissions results over the EPA 5-mode test cycle.)

CO	NOx + NMHC	PM	
0.67	**5.36**	**0.188**	Grams/kW-hr
0.50	**4.00**	**0.140**	Grams/bhp-hr

•The stated values are actual exhaust emission test measurements obtained from an engine representative of the type described above.
•Values based on 5-mode testing are official data of record as submitted to regulatory agencies for certification purposes. Testing was conducted in accordance with prevailing EPA protocol, which is typically accepted by SCAQMD and other regional authorities.
•No emissions values provided above are to be construed as guarantees of emission levels for any given Generac generator unit.
•Generac Power Systems, Inc. reserves the right to revise this information without prior notice.
•Consult state and local regulatory agencies for specific permitting requirements.
•The emission performance data supplied by the equipment manufacturer is only one element required toward completion of the permitting and installation process. State and local regulations may vary on a case-by-case basis and local agencies must be consulted by the permit application/equipment owner prior to equipment purchase or installation. The data supplied herein by Generac Power Systems cannot be construed as a guarantee of installability of the generating set.

MD500

For Generac Modular Power System (MPS)

Standby Power Rating

500KW 60 Hz

Prime Power Rating (1)

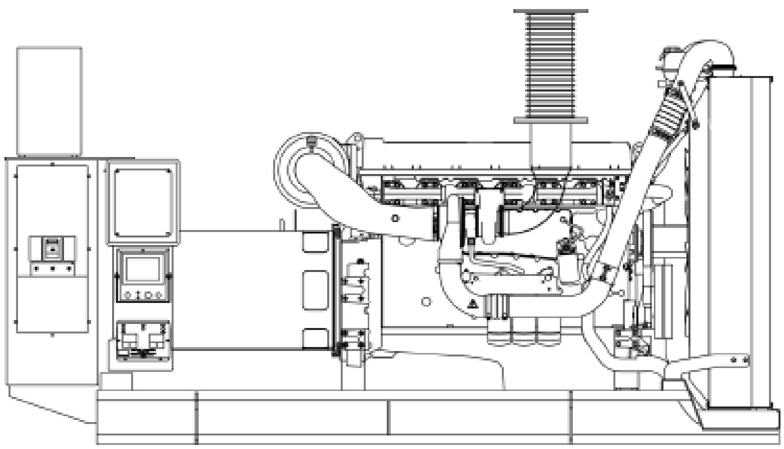
440KW 60 Hz

Power Matched

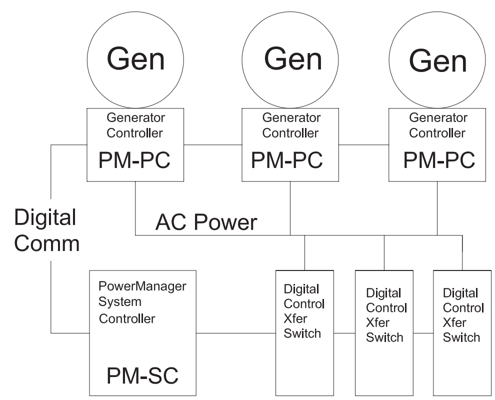
VOLVO 16.0DTA ENGINE

Turbocharged / Aftercooled

Tier II Compliant



PowerManager® Digital Control Platform



FEATURES

(1) Prime power unit not available at this time

- **INNOVATIVE DESIGN & PROTOTYPE TESTING** are key components of GENERAC'S success in "IMPROVING POWER BY DESIGN." But it doesn't stop there. Total commitment to component testing, reliability testing, environmental testing, destruction and life testing, plus testing to applicable CSA, NEMA, EGSA, and other standards, allows you to choose GENERAC POWER SYSTEMS with the confidence that these systems will provide superior performance.

- **PARALLELING SYSTEM FEATURES:**
  - ✓ AUTO SYNCHRONIZATION
  - ✓ ISOCHRONOUS LOAD SHARING
  - ✓ REVERSE POWER PROTECTION
  - ✓ MAXIMUM POWER PROTECTION
  - ✓ ELECTRICALLY OPERATED MECHANICALLY HELD TRANSFER SYSTEM
  - ✓ REDUNDANT OPERATION AND INCREASED RELIABILITY
  - ✓ UL2200 LISTED

- **POWERMANAGER DIGITAL CONTROL PLATFORM™.** The PowerManager Digital Control Platform (PM-DCP) is a powerful control system built around a 32-bit, industrial microprocessor. Standard factory programming controls the entire engine/generator system, while allowing the PM-DCP, with its onboard PLC, to be customized to meet any application requirement. The system is available on single unit gas, diesel or bi-fuel installations as well as Modular Paralleling Systems (MPS) from 350 kW - 3000 kW.

- **SINGLE SOURCE SERVICE RESPONSE** from Generac's dealer network provides parts and service know-how for the entire unit, from the engine to the smallest electronic component. You are never on your own when you own a GENERAC POWER SYSTEM.

- **ECONOMICAL DIESEL POWER.** Low cost operation due to modern diesel engine technology. Better fuel utilization plus lower cost per gallon provide real savings.

- **LONGER ENGINE LIFE.** Generac heavy-duty diesels provide long and reliable operating life.

- **GENERAC TRANSFER SWITCHES, POWERMANAGER® AND ACCESSORIES.** Long life and reliability is synonymous with GENERAC POWER SYSTEMS. One reason for this confidence is that the GENERAC product line includes its own transfer systems, accessories, and PowerManager® controls for total system compatibility.

GENERAC®

POWER SYSTEMS, INC.

GENERATOR SPECIFICATIONS

TYPE .... (480V) Four-pole, revolving field
Marathon (572RSL4024) Maganamax (208/240 Volts)
ROTOR INSULATION .... Class H
STATOR INSULATION .... Class H
LINE-TO-LINE HARMONIC FACTOR 5%
BALANCED TELEPHONE INFLUENCE FACTOR (TIF) .... <50
ALTERNATOR .... Self-ventilated and drip-proof
BEARINGS (PRE-LUBED & SEALED) 1
COUPLING .... Direct, Flexible Disc
LOAD CAPACITY (STANDBY) 100%
LOAD CAPACITY (PRIME) 110%

NOTE: Emergency loading in compliance with NFPA 99, NFPA 110. Generator rating and performance in accordance with ISO8528-5, BS5514, SAE J1349, ISO3046 and DIN6271 standards.

EXCITATION SYSTEM

❐ PERMANENT MAGNET PILOT EXCITER .... Eighteen-pole exciter ✓
Magnetically coupled DC current ✓
Mounted outboard of main bearing ✓
REGULATION .... H100 Controller Digital ✓
3 Phase Sensing, ± 1% regulation ✓

GENERATOR FEATURES

- ❐ Revolving field heavy duty generator
- ❐ Directly connected to the engine
- ❐ Operating temperature rise 120 °C above a 40 °C ambient
- ❐ Insulation is Class H rated at 150 °C rise
- ❐ All prototype models have passed three phase short circuit testing

CONTROL PANEL FEATURES

❐ TOUCH SCREEN DISPLAY PANEL READS:

- Voltage (all phases)
- Power factor
- kVAR
- Engine speed
- Run hours
- Fault history
- Coolant temperature
- Low oil pressure shutdown
- Overvoltage
- Low coolant level
- Not in auto position (flashing light)
- ATS selection
- Current (all phases)
- kW
- Transfer switch status
- Low fuel pressure
- Service reminders
- Oil pressure
- Time and date
- High coolant temperature shutdown
- Overspeed
- Low coolant level
- Exercise speed

❐ INTERNAL FUNCTIONS:

- I^2T function for alternator protection from line to neutral and line to line short circuits
- Emergency stop
- Programmable auto crank function
- 2 wire start for any transfer switch
- Communicates with the Generac HTS transfer switch
- Built-in 7 day exerciser
- Adjustable engine speed at exerciser
- RS232 port for GenLink® control
- RS485 port remote communication
- Canbus addressable
- Governor controller and voltage regulator are built into the master control board
- Temperature range -40 °C to 70 °C

ENGINE SPECIFICATIONS

MAKE .... VOLVO
MODEL TAD1641GE
CYLINDERS 6-Inline
DISPLACEMENT - liter/(cu. in.) 16.12 (983.7)
BORE - mm/(in.) 144 (5.67)
STROKE - mm/(in.) 165 (6.5)
COMPRESSION RATIO 16.5:1
INTAKE AIR .... Turbocharged/Aftercooled (Air to air)
NUMBER OF MAIN BEARINGS .... 7 with one thrust
CONNECTING RODS .... I-Beam Section
CYLINDER HEAD .... One piece cast iron
PISTONS .... Aluminum w/ cooling cavity, oil cooled
CRANKSHAFT .... Drop forged, counter weighted type

VALVE TRAIN

NUMBER OF VALVES .... 24-2 EX & 2 In./Cylinder
VALVES .... Chrome over steel
VALVE SENT .... Steel-replaceable

ENGINE GOVERNOR

❐ ELECTRONIC .... Standard
FREQUENCY REGULATION, NO LOAD TO FULL LOAD .... Isochronous
STEADY STATE REGULATION .... ± 0.25%

LUBRICATION SYSTEM

TYPE OF OIL PUMP .... Gear
OIL FILTER .... Bypass and Full Flow Cartridge
CRANKCASE CAPACITY - liter/(gal.) 48 (12.7)

COOLING SYSTEM

TYPE OF SYSTEM .... Pressurized, Closed Recovery
WATER PUMP .... Centrigugal Type/Belt Driven
TYPE OF FAN .... Pusher
NUMBER OF FAN BLADES 9
DIAMETER OF FAN - mm/(in.) 889 (35.0)
COOLANT HEATER 240V (4000W)

FUEL SYSTEM

FUEL .... No. 2 Diesel Fuel
(Fuel should conform to ASTM D975)
FUEL FILTER .... Full Flow Cartridgte
FUEL INJECTION PUMP Delphi/E1
FUEL PUMP .... Mechanical
INJECTORS .... Bosch, Multi-hole
FUEL LINE (Supply) .... 1/2" FNPT
FUEL RETURN LINE .... 1/2" FNPT

ELECTRICAL SYSTEM

BATTERY CHARGE ALTERNATOR .... 80 Amps at 24V
STARTER MOTOR .... 7.0 kW at 24V
RECOMMENDED BATTERY .... (2) - 12V, 31
GROUND POLARITY .... Negative

Rating definitions - Standby: Applicable for supplying emergency power for the duration of the utility power outage. No overload capability is available for this rating. (All ratings in accordance with BS5514, ISO3046 and DIN6271). Prime (Unlimited Running Time): Applicable for supplying electric power in lieu of commercially purchased power. Prime power is the maximum power available at variable load. A 10% overload capacity is available for 1 hour in 12 hours. (All ratings in accordance with BS5514, ISO3046, ISO8528 and DIN6271). Prime power is not available at this time for MPS units.

MD500 MPS

OPERATING DATA

	STANDBY			
	MD500			
GENERATOR OUTPUT VOLTAGE/KW—60Hz NOTE: Consult your Generac dealer for additional voltages.	**KW**		**Rated AMP**	
277/480V, 3-phase, 0.8 pf	500		752	
600V, 3-phase, 0.8 pf	500		601	
MOTOR STARTING KVA				
Locked rotor kVA at 35% instantaneous voltage dip with standard alternator; 60 Hz-kVA * see note 1	**480V** 1325			
FUEL				
Fuel consumption—60 Hz — Load	**125 kW**	**250 kW**	**375 kW**	**500 kW**
* see note 3 — gal./hr.	8.7	15.3	22.7	31.3
Fuel pump lift — in.	40			
COOLING				
Coolant capacity — System - lit./gal.	60 (15.85)			
Engine - lit./gal.	33 (8.72)			
Radiator - lit./gal.	27 (7.13)			
Coolant flow/min. — 60 Hz - lit./gal.	462 (122.4)			
Heat rejection to coolant — 60 Hz - BTU/hr.	778,220			
Radiator air flow — 60 Hz - m^3/min. (cfm)	660 (23,308)			
Max. operating air temp to radiator — °C (°F)	60 (140) * see note #5			
Max. operating ambient temp — °C (°F)	50 (122) * see note #5			
Max. external pressure drop after radiator — in. H_2O	4.0			
COMBUSTION AIR REQUIREMENTS				
Flow at rated power — 60 Hz - m^3/min. (cfm)	45.8 (1617)			
EXHAUST				
Exhaust flow at rated output — 60 Hz - m^3/min. (cfm)	110.4 (3899)			
Maximum recommended back pressure — kPa (in. Hg) [in. H_2O]	10 (3) [40]			
Exhaust temperature at rated output — °C (°F)	479 (893)			
Exhaust outlet size — inches ANSI	8			
ENGINE				
Rated RPM — 60 Hz	1800			
HP at rated kWe (gross) — 60 Hz - BHP	757			
Piston speed — 60 Hz - m/sec. (ft./min)	594 (1956)			
BMEP — 60 Hz - psi	339			
POWER ADJUSTMENTS FOR AMBIENT CONDITIONS				
Temperature — -4.5% for every 10° C above - C°	40			
-2.5% for every 10°F above - F°	104			
Altitude — -0.8% for every 100 m above - m	1630			
-2.5% for every 1000 ft. above - ft.	5000			

Notes:

1. Motor starting kVA adds directly for each generator on the bus. With Generac's PowerManager® Digital Control Platform, the load is shared proportionally.
2. Maximum distance between generator sets is determined by the voltage drop of the power conductors and the maximum distance allowed for the RS485 connection. If the distance between units exceeds 500 feet, consult your Generac representative for wire and communication recommendations.
3. Fuel consumption like motor starting kVA is additive. Each generator will proportionally share the load and the fuel consumption will be based on the percentage of load shared.
4. A complete MPS system requires a PowerManager Paralleling Controller (PM-PC), a PowerManager System Controller (PM-SC), and switch(es) from Generac Power System's GTS line of digitally controlled transfer switches. In addition, Generac Power Systems' Genlink® Communications Software provides remote monitoring and user interface with the Power Manager Digital Control Platform.
5. Values given are maximum temperatures to which power adjustment factors can be applied. Consult your Generac representative if operating conditions exceed these maximums.

STANDARD ENGINE & SAFETY FEATURES

- High Coolant Temperature Automatic Shutdown
- Low Coolant Level Automatic Shutdown
- Low Oil Pressure Automatic Shutdown
- Overspeed Automatic Shutdown (Solid-state)
- Crank Limiter (Solid-state)
- Oil Drain Extension
- Radiator Drain
- Factory-Installed Cool Flow Radiator
- Radiator Duct Adapter On Open Genset
- Closed Coolant System
- UV/Ozone Resistant Hoses
- Rubber-Booted Engine Electrical Connections
- Stainless Steel Flexible Exhaust Connection
- Battery Charge Alternator
- Battery Cables
- Battery Tray
- 24 Volt, Solenoid-activated Starter Motor
- Air Cleaner
- Fan Guard
- Control Console
- Isochronous Governor
- Jacket water heater
- Autosynchronizer
- Isochronous Load Sharing Module
- Reverse Power Protection Relay
- Dead Bus Sensing
- Sync Check Relay
- Main Line Circuit Breaker
- 2 Year Warranty

POWERMANAGER® DIGITAL CONTROL PLATFORM

The PowerManager Paralleling Controller (PM-PC) is a fully programmable, integrated digital generator control console using a 32-bit industrial microprocessor to handle all control, monitoring, input/output genset functions. The open architecture used allows customizing the controls to meet any customer requirement, yet maintaining the simplicity of operating 'as is' with the factory default programming. (see Generac bulletin #0168840SBY)

GENERATOR CONNECTIONS

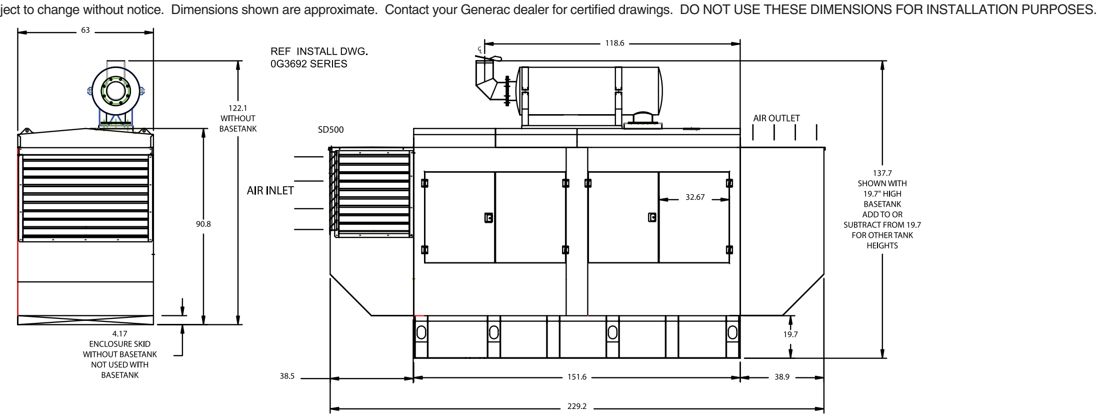
1. 4 Wire load connections from Paralleling Switch to optional connection box bus or transfer switch bus. Paralleling Switch has 4 lugs per phase – each lug will accept 4/0 to 350MCM aluminum or copper conductor.
2. 2 wire shielded cable (RS485) to PowerManager System Control or PowerManager Integral Control
3. 2 wire twisted pair from transfer switch (when multiple transfer switches are used). Can also go to the PowerManager System Controller
4. 120Volt 15 amp input circuit for battery charger.
5. 240Volt 20 amp input for coolant heater.

OPTIONS

- **OPTIONAL FUEL ACCESSORIES**
  - Base Tank Low Fuel Alarms
  - Secondary Fuel Filters, Heaters and Water Alarms
  - UL Listed Fuel Tanks / Daytanks
  - Electric Fuel Transfer Pump System
- **OPTIONAL ELECTRICAL ACCESSORIES**
  - 10A Dual Rate Battery Charger
  - Battery, 24 Volt
  - Battery Warmer
  - 500MCM Lugs on Paralleling Switch (4 lugs per phase)
- **OPTIONAL ALTERNATOR ACCESSORIES**
  - Alternator Heater
- **OPTIONAL EXHAUST ACCESSORIES**
  - Critical Residential or Industrial Exhaust Silencers
  - Installed Low-Profile Critical Muffler (available on sound attenuated enclosure)
  - Single Exhaust System (available on open genset)
- **GENERAC POWERMANAGER® SYSTEM CONTROLLER FOR COORDINATION OF GENERATOR(S) AND TRANSFER SWITCHE(ES)**
  - See Spec 0169060SBY For Additional Information
- **ADDITIONAL OPTIONAL EQUIPMENT**
  - 20 Light Remote Annunciator
  - Remote Relay Panels
  - Oil Heater
  - 5 Year Warranties
  - GenLink® Communications Software
- **OPTIONAL ENCLOSURES**
  - Weather Protective
  - Sound Attenuated
  - Aluminum

Distributed by:

Design and specifications subject to change without notice. Dimensions shown are approximate. Contact your Generac dealer for certified drawings. DO NOT USE THESE DIMENSIONS FOR INSTALLATION PURPOSES.



GENERAC® POWER SYSTEMS, INC. • P.O. BOX 8 • WAUKESHA, WI 53187

262/544-4811 • FAX 262/544-0770

Bulletin 0173630SBY / Printed in USA 10.06, rev. 12.06

TAB 10

PERMIT TO CONSTRUCT APPLICATION FEE

A check in the amount of $1,000.00 for the Permit to Construct Application Fee is included.

TAB 11

Publication: Standard Journal;**Date:**Nov 19, 2013;**Section:**Comics;**Page Number:**7B[Back][Continuation]

Loan No. xxxxxx6818 T.S. No. 1368459-37 Parcel No. rp07n39e142555 **NOTICE OF TRUSTEE'S SALE** On **March 20, 2014**, at th hour of 11:00am, of said day, at In the foyer o the Fremont county courthouse, 151 west 1st Street North, St. Anthony, Idaho, First Americ n Title Insurance Company, as trustee, will sell t public auction, to the highest bidder, for cash, cashier's check drawn on a State or National Bank, a check drawn by a State or Federal Credit Union, or a check drawn by a State or Federal Savings and Loan Association, Savings Association, or Savings Bank, all payabl at the time of sale, the following described rea property, situated in the County of Fremont, state of Idaho, and described as follows, to w COMMENCING AT A POINT 78 RODS WES OF THE NE CORNER OF THE NE1/4NW1/4 OF SECTION 14, TOWNSHIP 7 NORTH, RANGE 39 E.B.M., FREMONT COUNTY, IDA HO, AND RUNNING THENCE SOUTH 270 FEET; THENCE EAST 200 FEET; THENCE NORTHEASTERLY TO A POINT WHICH IS 450 FEET EAST OF THE POINT OF BEGINNING; THENCE WEST 450 FEET TO THE POINT OF BEGINNING. ***home loans, a division of first tennessee bank national association, master servicer, in its capacity as agent for the trustee under the pooling and servicing agreement** Commonly known as 1626 East 400 North Street Saint Anthony Id 83445. Said sale will be made without covenant or warranty, express or implied, regarding title, possession or encumbrances to satisfy the obligation secured by and pursuant to the power of sale conferred in the Deed of Trust executed by Joseph Francis Carroll & Patti Lynn Carroll, Husband & Wife as Grantor, to First American, as Trustee, for the benefit and security of Mortgage Electronic Registration Systems, Inc., ("mers") As Nominee For First Horizon Home Loan Corporation, Its Successors and Assigns as Beneficiary, recorded October 19, 2005, as Instrument No. 498427, Mortgage records of Fremont County, Idaho. THE ABOVE GRANTORS ARE NAMED TO COMPLY WITH SECTION 45-1506(4)(a), IDAHO CODE. NO REPRESENTATION IS MADE THAT THEY ARE, OR ARE NOT, PRESENTLY RESPONSIBLE FOR THIS OBLIGATION. The default for which this sale is to be made is: Failure to pay the monthly payment due April 1, 2012 of interest only plus impounds and subsequent installments due thereafter; plus late charges; together with all subsequent sums advanced by beneficiary pursuant to the terms and conditions of said deed of trust. The estimated balance owing as of this date on the obligation secured by said deed of trust is $99,272.47, including interest, costs and expenses actually incurred in enforcing the obligation thereunder or in this sale, and trustee's fees and/or reasonable attorney's fees as authorized in the promissory note secured by the aforementioned Deed of Trust. First American Title Insurance Company C/o Cal-western Reconveyance Llc P.O. Box 22004 El Cajon Ca 92022-9004 (800)546-1531 Dated: November 4, 2013 Signature/By First American Title Insurance Company. DLPP-434155

Published 11/19/13, 11/26/13, 12/03/13, & 12/10/13
SJ6266

LEGAL

Legal notice

Brigham Young University Idaho, hereafter known as "Owner", is submitting a request to the State of Idaho Department of Environmental Quality (DEQ) seeking permission to raze the existing coal fired central boilers and replace them with gas fired central boilers. The Owner's intent in seeking a "Permit to Construct" is continued compliance with requirements of the Environmental Protection Agency and DEQ. Final approval of the Permit to Construct will be issued by DEQ.

A copy of the Owner's Permit to Construct application filed with DEQ is available for review at the offices of Facilities Planning and Construction Department between the hours of 9:00 am and 5:00 pm.

An informational meeting will be held on Monday, December 2, 2013 from 9:00 to 11:00 AM in the University Operations Building, Room 283 to review the "Permit to Construct".

Owner's Address:
University Operations Building
Facilities Planning and Construction Department
450 South Physical Plant Way
Rexburg, Idaho 83460-8205

Telephone: 208-496-2651
Fax: 208-496-2653
E-Mail: permittoconstruct@byui.edu

Published 11/19/13
SJ6277

FREMONT SCHOOL DISTRICT #215
945 W 1 N
ST. ANTHONY, IDAHO 83445

SCHOOL BUS BID FORM
****** *** *** ****

Fremont School District # 215 is calling for bids for one (1) transit bus forward control and one (1) or more conventional bus or buses. Included herewith are chassis and body specifications and bid forms.

NOTE:

It is intended that Fremont School District #215 will purchase one transit bus and one or more conventional buses at the time the award of bids is made for this bid. However, the option for Fremont School District #215 to purchase additional buses on this same bid and at the same price, if the School District chooses to do so.

Bid Information:

All bids are to be submitted on the enclosed forms, in a sealed envelope with "Bus Bids -1:00 P.M. **December 17, 2013**" marked on the outside. Any deviations from the specifications or conflicts with Federal or State Codes are to be so noted on a sheet and attached to this bid form.
All bids must be at the Office of the Superintendent, at the above address, by 1:00 p.m. on the **17th Day of December 2013**, at which time the bids will be opened and read aloud. The bids will be presented at a regular Board meeting for Board action.

The School District reserves the right to reject any or all bids or to accept the bid or bids deemed best for the School District and to waive any technicality.

Bid Notes:

1. Open to except approved equal to or equivalent to.
2. Early production and availability is up to the factory, however no "flooring" or interest charges will be allowed.

Published 11/16/13 & 11/19/13
SJ6273

NOTICE OF ASSESSMENT
Lenroot Canal Company

NOTICE IS HEREBY GIVEN that at a meeting of th Directors of Lenroot Canal Company held Monday, N 11, 2013, an assessment of $17.00 per share with a mum charge was levied upon the capital stock of the tion. Assessments will be payable by November 30, Lenroot Canal Company.

ANY STOCK UPON WHICH this assessment rema December 1, 2013, will be delinquent and will be cha penalty plus 1 1/2% interest per month until paid in fu

Payment may be made by mail or in person to the

722
Rexbu

Published 11/16/13, 11/19/13, & 11/21/13
SJ6272

IN THE DISTRICT COURT FOR THE SEVENTH JUDICIAL DISTR
STATE OF IDAHO, COUNTY OF BONNEVILLE

RIC OTTEWITTE and NANCY TTEWITTE,
Plaintiff,

V.

I. CAROLINE EDWARD, individually; M. AROLINE EDWARD as surviving spouse nd putative personal representative of THE STATE OF ROBERT W. EDWARD, eceased; FIA CARD SERVICES, N.A.; fka MBNA AMERICA BANK, N.A.; BONNEVILLE BILLING & COLLECTIONS, INC.; CAPITAL ONE BANK (USA), N.A.; and JOHN DOES 1-10;
Defendants.

Case No. CV-2013-304

NOTICE OF SALE

DATE OF SALE: December 11, 2013
TIME OF SALE: 10:30 a.m.
PLACE OF SALE: Fremont county sheriff's office
Lobby of the courthouse
151 West 1st Main
St. Anthony, Idaho 83445

Under nand by viture of an Writ of Execution by Sheriff issued on the 23rd c September 2013, out of and under the seal of the above-entitled Court on a in said Court in the above-entitled action on the 22nd day of August 2013, in f above-named plaintiff and against the Defendants, I am commanded and re proceed to notice for sale and to sell at public auction the property describe der of Sale and to applythe proceeds of such sale to the satisfaction of said of Foreclosure with interest thereon, and attorney fees and costs for sale, ar and costs. **The minimum bid is $255,863.85, plus accrued interest and c**
The property directed to be sold is situate in Fremont Count, State of Idah scribed as follows, to wit:
Lot 8, Block 6, Shotgun Village Estates Division No. 2, Fremont Coun shown on the plat recorded May 10, 1971, as Instrument No. 322866.
Lot 10, Block 6, Shotgun Village Estates Division No. 2, Fremont County, I
These properties are commonly known as: 3545 Browning Road, Idaho and 3549 Browning Road, Island Park, Idaho.
The Sheriff, by certificate of sale, will transfer the right, title, and interest of dants in and to the property at the time of the execution r attachment was le Sheriff will give possession, but does not guarantee clear title nor continued right to the purchaser.
Following issuance of the Sheriff's Certificate of Sale there is a statutory si demption period, during which time judgement Debtor or any redemptioner r the above property.If no redemption is made within that six month period, the upon expiration of the redemption period, shall issue its Dees conveying title above property.
NOTICE IS HEREBY GIVEN, that on the 11th day of December 2013, at th 10:30 o' clock a.m. In the foyer of the Fremont County Courthouse, 151 Wes St. Anthony, Idaho, I will attend, offer and sell at public auction all or so muc above-described property thus directed to be sold as may be necessary to r cient fund to pay and satisfy the Judgement of Foreclosure as set out in sai Sale by Sheriff to the highest bidder therefore in lawful money.

DATED THIS 28th day of October 2013.

SHERIFF
Fremont County, Idaho

By: /S/ Vicki Johnson
Deputy

CHARLES C. JUST, ESQ. - ISB 1779
KIPP L. MANWARING, ESQ. - ISB 3817
JUST LAW OFFICE
381 Shoup Avenue
P.O. Box 50271
Idaho Falls, Idaho 83405
Telephone: (208) 523-9106
Facsimile: (208) 523-9146
Attorneys for the Plaintiffs

Published 11/05/13, 11/12/13, & 11/19/13
SJ6256

NOTICE OF TRUSTEE SALE

1. **Date, Time, and Place of Sale.**

   Date: Monday, January 6, 2014

   Time: 9:30 a.m.

   Place: The law offices of Beard St. Clair Gaffney PA, 520 First American Circle, Rexburg, ID 83440.

2. **Instrument to be Foreclosed.** Deed of Trust dated June 11, 1997 and recorded in the office of the Madison County Recorder on June 12, 1997 as Instrument No. 266858 between Michael P. Kennelly and Melanie D. Kennelly, Grantors, and First American Title Company of East Idaho, Trustee, for the benefit of Western Omni Corporation, Beneficiary, to secure the performance of the Grantors' obligations

Lisa McMahon-Myhran, ISB #8963
Jennifer Tait, ISB #8243

TAB 12

PROCESS DESCRIPTION

Brigham Young University - Idaho is proposing to replace their existing Central Heating Plant with a new Central Energy Facility. The existing Central Chilled Water Plant which is on the east end of the existing Heating Plant will remain. The existing Heating Plant will remain in service until the new facility is operational.

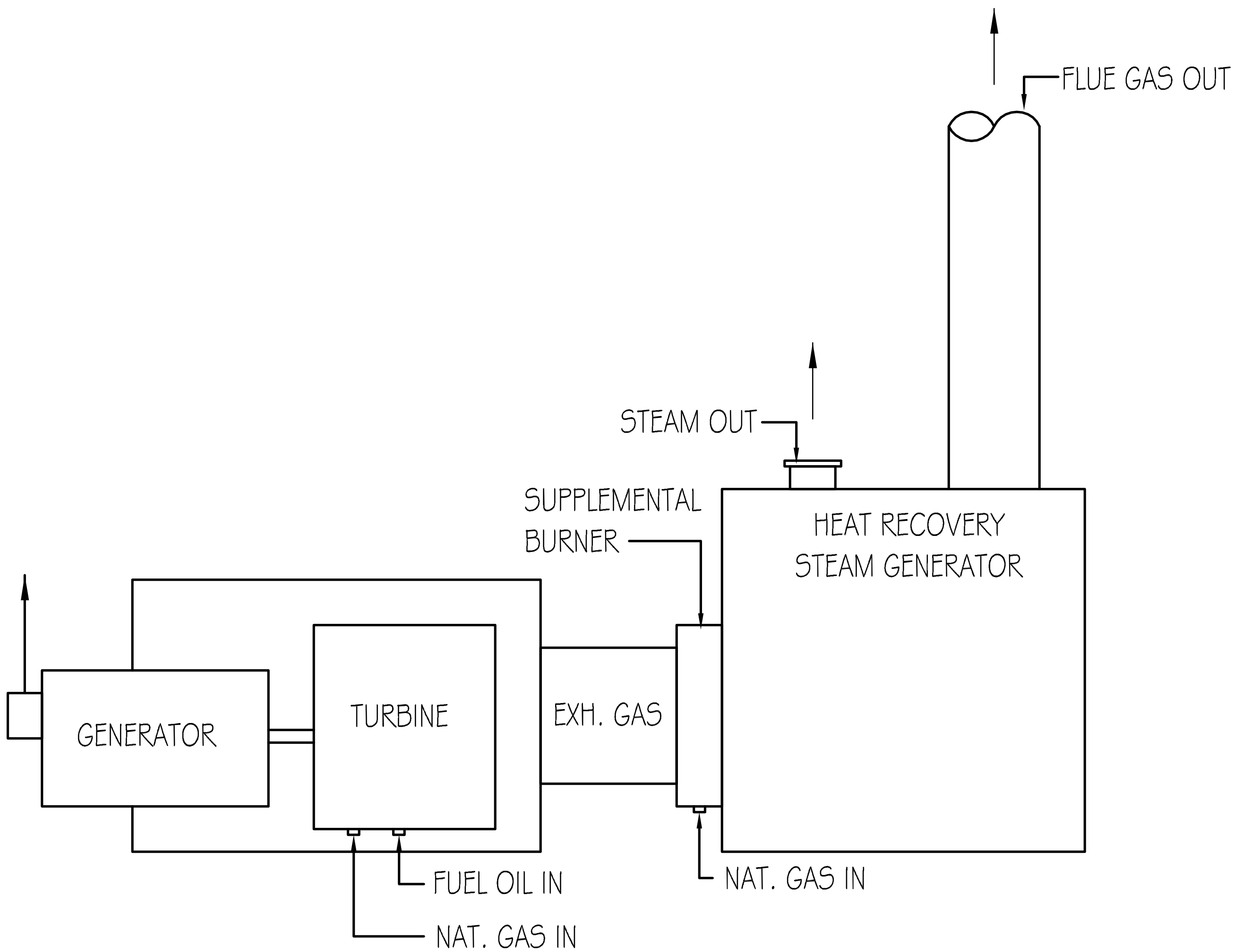
The existing plant houses three coal fired boilers and one combination natural gas/oil fired boiler. The coal boilers are No. 1 with an input capacity of 26.7 MMBtu/hr, No. 2 with an input capacity of 40 MMBtu/hr and No. 3 with an input capacity of 46.7 MMBtu/hr. The single natural gas/oil fired boiler No. 5 has an input capacity of 50 MMBtu/hr.

The new proposed Central Energy Facility will house a natural gas/oil fired 4.5 megawatt. Turbine with the exhaust gas used to produce 25,000 lbs steam/hr in a Heat Recovery Steam Generator (HRSG). The HRSG Boiler No. 1 also has a supplemented natural gas burner with an input capacity of 30 MMBtu/hr.

Two new natural gas/oil boilers No. 2 and No. 3 are proposed. Each will have an input capacity of 55 MMBtu/hr.

The existing natural gas/oil fired boiler will be relocated from the existing plant and be refurbished with a new combinaton natural gas/oil fired burner. This boiler will be No. 4 and have an input capacity of 50 MMBtu/hr.

Two existing oil fired 500 KW emergency generators will remain and a new oil fired 1,000 KW ((2) 500 KW units in one housing) emergency generator will be added.



TURBINE GENERATOR/HEAT RECOVERY STEAM GENERATOR (HRSG) - PROCESS SCHEMATIC

SCALE: NONE

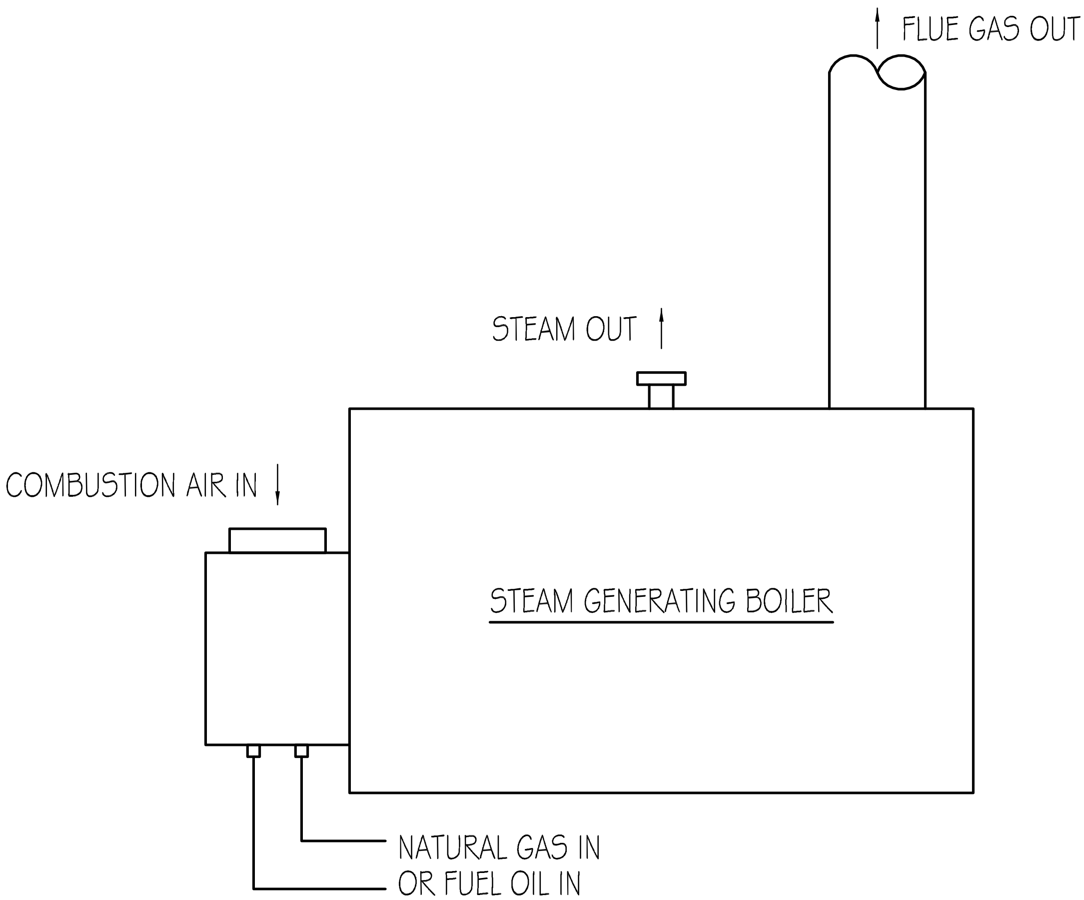
HEATH Engineering Company
Mechanical/Electrical/Plumbing Consultants
377 West 800 North Salt Lake City, Utah 84103 Tel: (801) 322-0487 Fax: (801) 322-0490

PROJECT BYU-IDAHO CENTRAL ENERGY FACILITY

CLIENT BYU-IDAHO

BY HEC DATE 10/02/2013

DRAWING # A



STEAM GENERATING BOILER - PROCESS SCHEMATIC

SCALE: NONE —————— TYPICAL BOILERS #2, #3, #4 (#5 FUTURE)

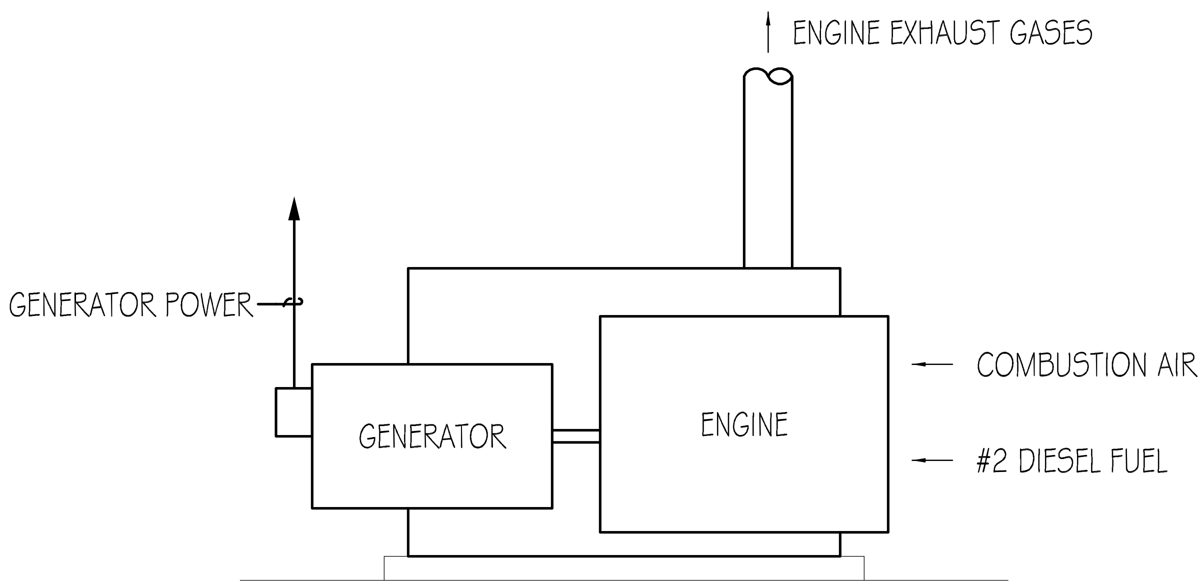
HEATH
Engineering Company
Mechanical/Electrical/Plumbing Consultants
377 West 800 North Salt Lake City, Utah 84103 Tel: (801) 322-0487 Fax: (801) 322-0490

PROJECT BYU-IDAHO CENTRAL ENERGY FACILITY

CLIENT BYU-IDAHO

BY HEC DATE 10/02/2013

DRAWING # B



ENGINE GENERATOR SET - PROCESS SCHEMATIC

SCALE: NONE

HEATH
Engineering Company
Mechanical/Electrical/Plumbing Consultants
377 West 800 North Salt Lake City, Utah 84103 Tel: (801) 322-0487 Fax: (801) 322-0490

PROJECT BYU-IDAHO CENTRAL ENERGY FACILITY

CLIENT BYU-IDAHO

BY HEC DATE 10/02/2013

DRAWING # C

TAB 13

EQUIPMENT LIST

BYU – Idaho,
Rexburg, Idaho
Fuel Fired Steam Generating and Power Generating Equipment List

Equipment Item	**Manufacturer**	**Model**	**Fuel Input Rating**
4.5 megawatt, Gas/Oil Fired Turbine, (EU-01) Exhaust Gas Discharge into Heat Recovery Steam Generator (HRSG) (Unit #1)	Solar Turbine	Taurus 60-7901S (Final unit model # pending)	60 MMBTU/HR Yields 25,000 lbs steam/hr
Supplemental Burner into Heat Recovery Steam Generator (HRSG) (EU-01A) (HRSG-1)	Natcom Duct Burner mounted at inlet to Cleaver Brooks HRSG	Burner: (Final burner model # pending) MF-4(S)-70 HRSG	30 MMBTU/HR Yields 25,000 lbs steam/hr
Gas/Oil Fired Boiler #2 (SB-2)	Natcom Burner mounted at inlet to Cleaver Brooks Type "O" Boiler	Burner: P-64-LOG-23-1117 Boiler: NOS-2-54 Industrial, water-tube boiler	55 MMBTU/HR Yields 45,000 lbs steam/hr
Gas/Oil Fired Boiler #3 (SB-3)	Natcom Burner mounted at inlet to Cleaver Brooks Type "O" Boiler	Burner: P-64-LOG-23-1117 Boiler: NOS-2-54 Industrial, water-tube boiler	55 MMBTU/HR Yields 45,000 lbs steam/hr
Gas/Oil Fired Boiler #4 (SB-4)	New Natcom Burner mounted at inlet to relocated Indeck Type "O" Boiler	Burner: P-50-LOG-23-1117 Boiler: Existing Indeck	50 MMBTU/HR Yields 40,000 lbs steam/hr
Standby Diesel Generating Set 1250 kVA/1000KW (EG-483) (EG-484)	Generac	Unit: MD1000 GEM	(2) 500 KW, 757 HP, Oil Fired
Existing Standby Diesel Generating Set 625 kVA/500KW (EG-481)	Generac	Unit: MD500 MPS	500 KW, 757 HP, Oil Fired
Existing Standby Diesel Generating Set 625 kVA/500KW (EG-482)	Generac	Unit: MD500 MPS	500 KW, 757 HP, Oil Fired

The remainder of the requested information is included in the permit to construct application included with this application or as provided on thumb drive and disk given directly to Cheryl A. Robinson.

TAB 14

SCALED PLOT PLAN

An earlier version of the BYU Idaho Plot Plan was included in the Permit to Construct Submittal sent earlier. The attached Plot Plan is the latest version. A disk of this Plot Plan in PDF form is included.

BYU-IDAHO

100' 50' 0 100' 200'

1"=100'-0"

N

TAB 15

Pre-Construction Services

Project Milestones

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
100	Proposal Due	0	0	100	25JUL13A	
110	Award Contract	5	0	100	25JUL13A	31JUL13A
140	Issue NTP	34	0	100	01AUG13A	18SEP13A
160	General Liability Insurance	5	0	100	19SEP13A	25SEP13A
170	Bond	5	0	100	19SEP13A	25SEP13A
135	Begin Construction	0	0	100	01OCT13A	
180	General Conditions/Fee	607*	585*	4	08OCT13A	29FEB16
155	Stop Burning Coal in Existing Facility	0	0	0	31MAR14*	
115	Two Boilers in New Facility are Operational	0	0	0	01OCT14*	
120	Phase 1B Substantial Completion	0	0	0		07NOV14
125	Phase 1A Substantial Completion	0	0	0		07APR15
130	Phase 2A Substantial Completion	0	0	0		15JUN15
145	Phase 2B Substantial Completion	0	0	0		29FEB16
150	Project Substantial Completion	0	0	0		29FEB16

Permiting

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
910	Issue Building Permit	0	0	100	27SEP13A	

Procurement, Submittals & Fabrication

Excavation & Structural Concrete

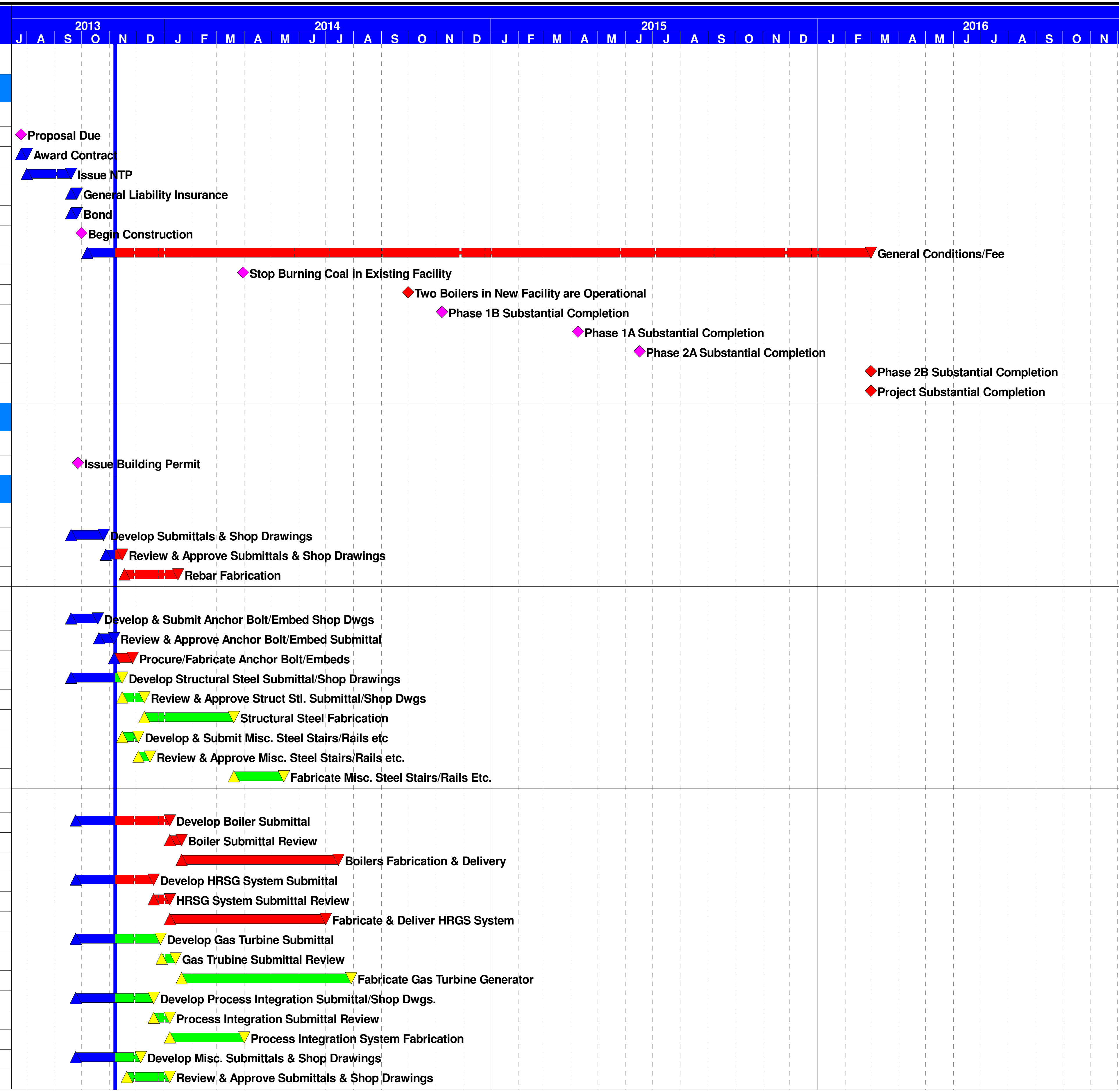
Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
685	Develop Submittals & Shop Drawings	20	0	100	19SEP13A	25OCT13A
690	Review & Approve Submittals & Shop Drawings	15	7	53	28OCT13A	15NOV13
695	Rebar Fabrication	40	40	0	18NOV13	16JAN14

Structural Steel

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
525	Develop & Submit Anchor Bolt/Embed Shop Dwgs	18	0	100	19SEP13A	18OCT13A
526	Review & Approve Anchor Bolt/Embed Submittal	10	0	100	21OCT13A	05NOV13A
527	Procure/Fabricate Anchor Bolt/Embeds	15	14	7	06NOV13A	26NOV13
505	Develop Structural Steel Submittal/Shop Drawings	28	6	79	19SEP13A	14NOV13
510	Review & Approve Struct Stl. Submittal/Shop Dwgs	15	15	0	15NOV13	09DEC13
515	Structural Steel Fabrication	70	70	0	10DEC13	19MAR14
530	Develop & Submit Misc. Steel Stairs/Rails etc	10	10	0	15NOV13	02DEC13
535	Review & Approve Misc. Steel Stairs/Rails etc.	10	10	0	03DEC13	16DEC13
540	Fabricate Misc. Steel Stairs/Rails Etc.	40	40	0	20MAR14	14MAY14

MEPS (Mech, Elect., Plumb, Sprinkler & Security)

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
615	Develop Boiler Submittal	70	39	44	25SEP13A	06JAN14
617	Boiler Submittal Review	10	10	0	07JAN14	20JAN14
575	Boilers Fabrication & Delivery	175	175	0	21JAN14	14JUL14
625	Develop HRSG System Submittal	60	29	52	25SEP13A	19DEC13
627	HRSG System Submittal Review	10	10	0	20DEC13	06JAN14
581	Fabricate & Deliver HRGS System	175	175	0	07JAN14	30JUN14
645	Develop Gas Turbine Submittal	65	34	48	25SEP13A	27DEC13
647	Gas Trubine Submittal Review	10	10	0	30DEC13	13JAN14
561	Fabricate Gas Turbine Generator	189	189	0	21JAN14	28JUL14
705	Develop Process Integration Submittal/Shop Dwgs.	60	29	52	25SEP13A	19DEC13
707	Process Integration Submittal Review	10	10	0	20DEC13	06JAN14
710	Process Integration System Fabrication	60	60	0	07JAN14	31MAR14
555	Develop Misc. Submittals & Shop Drawings	50	19	62	25SEP13A	05DEC13
560	Review & Approve Submittals & Shop Drawings	30	30	0	20NOV13	06JAN14



Start Date	15JUL13
Finish Date	29FEB16
Data Date	07NOV13
Run Date	08NOV13 11:25

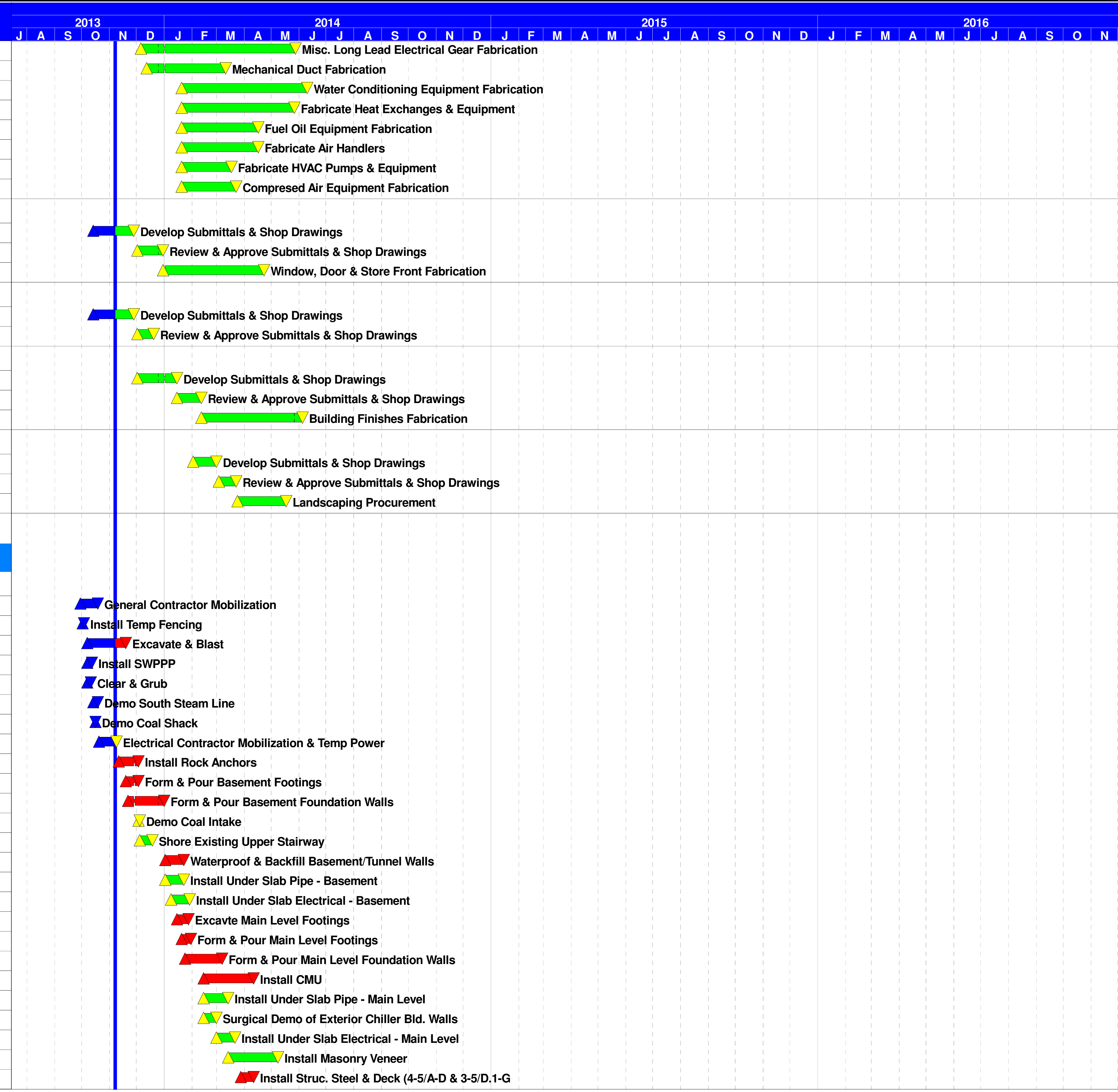
Early Bar
Progress Bar
Critical Activity

BI03

Sheet 1 of 6

BYU-Idaho
Central Energy Facility
Additions & Upgrades
Status as of 07 November 2013

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
565	Misc. Long Lead Electrical Gear Fabrication	120	120	0	06DEC13	27MAY14
570	Mechanical Duct Fabrication	60	60	0	13DEC13	10MAR14
577	Water Conditioning Equipment Fabrication	140	140	0	21JAN14	09JUN14
582	Fabricate Heat Exchanges & Equipment	125	125	0	21JAN14	25MAY14
578	Fuel Oil Equipment Fabrication	85	85	0	21JAN14	15APR14
583	Fabricate Air Handlers	85	85	0	21JAN14	15APR14
579	Fabricate HVAC Pumps & Equipment	55	55	0	21JAN14	16MAR14
576	Compresed Air Equipment Fabrication	60	60	0	21JAN14	21MAR14
Windows, Doors, & Roof						
580	Develop Submittals & Shop Drawings	20	15	25	14OCT13A	27NOV13
585	Review & Approve Submittals & Shop Drawings	20	20	0	02DEC13	30DEC13
590	Window, Door & Store Front Fabrication	80	80	0	31DEC13	22APR14
Framing & Drywall						
605	Develop Submittals & Shop Drawings	15	15	0	14OCT13A	27NOV13
610	Review & Approve Submittals & Shop Drawings	15	15	0	02DEC13	20DEC13
Building Finishes						
630	Develop Submittals & Shop Drawings	30	30	0	02DEC13*	14JAN14
635	Review & Approve Submittals & Shop Drawings	20	20	0	15JAN14	11FEB14
640	Building Finishes Fabrication	80	80	0	12FEB14	04JUN14
Sitework & Landscaping						
655	Develop Submittals & Shop Drawings	20	20	0	03FEB14*	28FEB14
660	Review & Approve Submittals & Shop Drawings	15	15	0	03MAR14	21MAR14
665	Landscaping Procurement	40	40	0	24MAR14	16MAY14
Construction Services						
Construction						
Phase 1A - New Heat Plant						
1000	General Contractor Mobilization	15	0	100	30SEP13A	18OCT13A
1001	Install Temp Fencing	5	0	100	02OCT13A	02OCT13A
1007	Excavate & Blast	30	8	73	08OCT13A	18NOV13
1002	Install SWPPP	5	0	100	08OCT13A	11OCT13A
1005	Clear & Grub	5	0	100	08OCT13A	10OCT13A
1165	Demo South Steam Line	5	0	100	14OCT13A	18OCT13A
1390	Demo Coal Shack	1	0	100	16OCT13A	16OCT13A
1380	Electrical Contractor Mobilization & Temp Power	15	2	87	21OCT13A	08NOV13
1017	Install Rock Anchors	15	15	0	11NOV13*	03DEC13
1010	Form & Pour Basement Footings	8	8	0	19NOV13	02DEC13
1080	Form & Pour Basement Foundation Walls	25	25	0	22NOV13	31DEC13
1045	Demo Coal Intake	2	2	0	03DEC13	04DEC13
1155	Shore Existing Upper Stairway	10	10	0	05DEC13	18DEC13
1060	Waterproof & Backfill Basement/Tunnel Walls	15	15	0	02JAN14	22JAN14
1180	Install Under Slab Pipe - Basement	15	15	0	02JAN14	22JAN14
1190	Install Under Slab Electrical - Basement	15	15	0	09JAN14	29JAN14
1070	Excavte Main Level Footings	8	8	0	16JAN14	27JAN14
1090	Form & Pour Main Level Footings	8	8	0	21JAN14	30JAN14
1100	Form & Pour Main Level Foundation Walls	30	30	0	24JAN14	06MAR14
1015	Install CMU	40	40	0	14FEB14	10APR14
1200	Install Under Slab Pipe - Main Level	20	20	0	14FEB14	13MAR14
1115	Surgical Demo of Exterior Chiller Bld. Walls	10	10	0	14FEB14	27FEB14
1210	Install Under Slab Electrical - Main Level	15	15	0	28FEB14	20MAR14
1175	Install Masonry Veneer	40	40	0	14MAR14	08MAY14
1065	Install Struc. Steel & Deck (4-5/A-D & 3-5/D.1-G	10	10	0	28MAR14	10APR14



Start Date	15JUL13
Finish Date	29FEB16
Data Date	07NOV13
Run Date	08NOV13 11:25

Early Bar
Progress Bar
Critical Activity

BI03

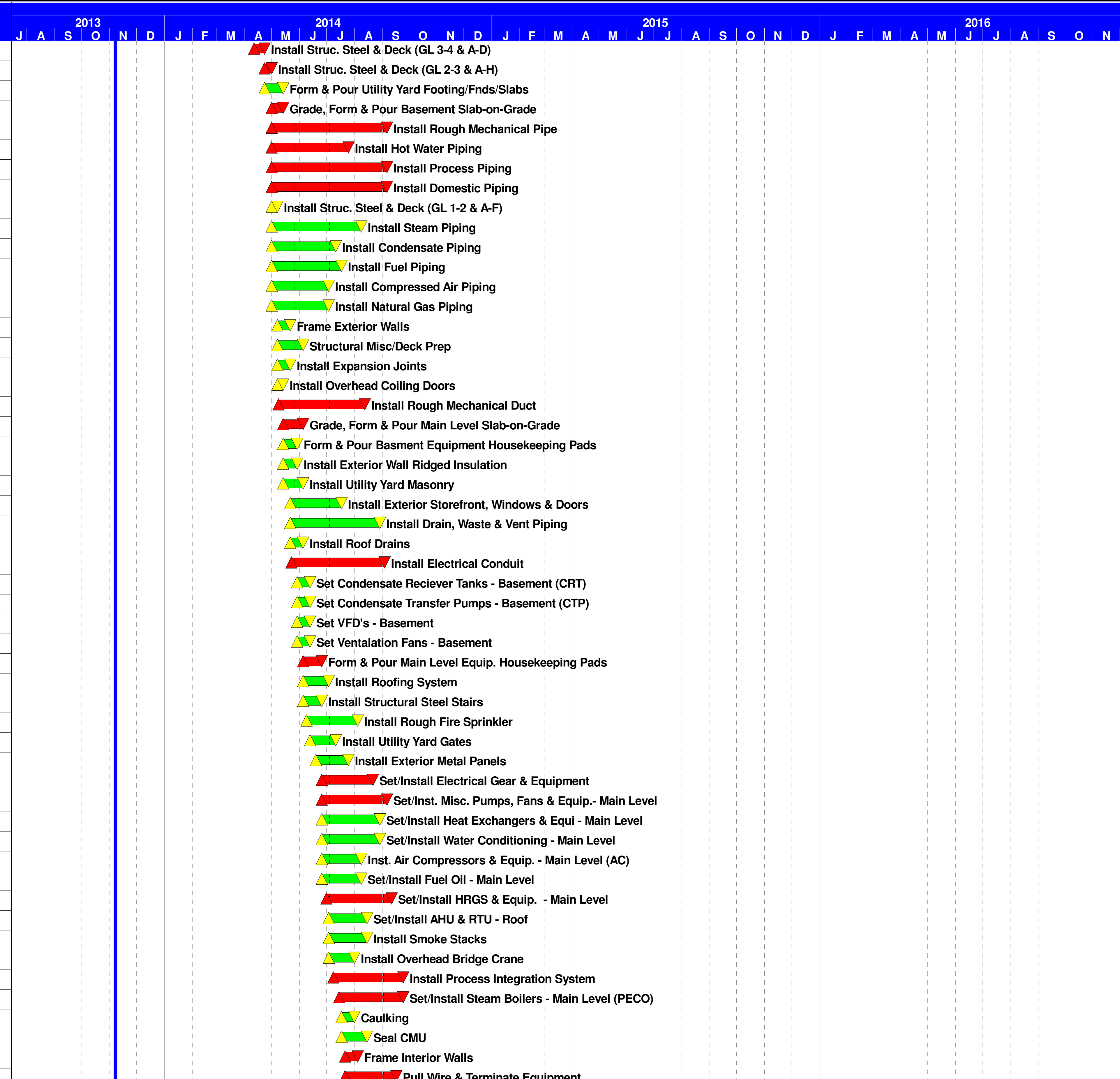
Sheet 2 of 6

BYU-Idaho
Central Energy Facility
Additions & Upgrades
Status as of 07 November 2013

BYU IDAHO

BIG-D CONSTRUCTION

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
1185	Install Struc. Steel & Deck (GL 3-4 & A-D)	8	8	0	11APR14	22APR14
1195	Install Struc. Steel & Deck (GL 2-3 & A-H)	5	5	0	23APR14	29APR14
1125	Form & Pour Utility Yard Footing/Fnds/Slabs	15	15	0	23APR14	13MAY14
1075	Grade, Form & Pour Basement Slab-on-Grade	10	10	0	30APR14	13MAY14
1110	Install Rough Mechanical Pipe	90	90	0	30APR14	05SEP14
1220	Install Hot Water Piping	60	60	0	30APR14	24JUL14
1240	Install Process Piping	90	90	0	30APR14	05SEP14
1300	Install Domestic Piping	90	90	0	30APR14	05SEP14
1205	Install Struc. Steel & Deck (GL 1-2 & A-F)	5	5	0	30APR14	06MAY14
1260	Install Steam Piping	70	70	0	30APR14	07AUG14
1250	Install Condensate Piping	50	50	0	30APR14	10JUL14
1270	Install Fuel Piping	55	55	0	30APR14	17JUL14
1280	Install Compressed Air Piping	45	45	0	30APR14	02JUL14
1230	Install Natural Gas Piping	45	45	0	30APR14	02JUL14
1555	Frame Exterior Walls	10	10	0	07MAY14	20MAY14
1645	Structural Misc/Deck Prep	20	20	0	07MAY14	04JUN14
1325	Install Expansion Joints	10	10	0	07MAY14	20MAY14
1485	Install Overhead Coiling Doors	5	5	0	07MAY14	13MAY14
1020	Install Rough Mechanical Duct	65	65	0	09MAY14	11AUG14
1085	Grade, Form & Pour Main Level Slab-on-Grade	15	15	0	14MAY14	04JUN14
1215	Form & Pour Basment Equipment Housekeeping Pads	10	10	0	14MAY14	28MAY14
1560	Install Exterior Wall Ridged Insulation	10	10	0	14MAY14	28MAY14
1465	Install Utility Yard Masonry	15	15	0	14MAY14	04JUN14
1025	Install Exterior Storefront, Windows & Doors	40	40	0	21MAY14	17JUL14
1310	Install Drain, Waste & Vent Piping	70	70	0	21MAY14	28AUG14
1340	Install Roof Drains	10	10	0	21MAY14	04JUN14
1140	Install Electrical Conduit	70	70	0	23MAY14	02SEP14
1105	Set Condensate Reciever Tanks - Basement (CRT)	10	10	0	29MAY14	11JUN14
1235	Set Condensate Transfer Pumps - Basement (CTP)	10	10	0	29MAY14	11JUN14
1245	Set VFD's - Basement	10	10	0	29MAY14	11JUN14
1255	Set Ventalation Fans - Basement	10	10	0	29MAY14	11JUN14
1225	Form & Pour Main Level Equip. Housekeeping Pads	15	15	0	05JUN14	25JUN14
1030	Install Roofing System	20	20	0	05JUN14	02JUL14
1545	Install Structural Steel Stairs	15	15	0	05JUN14	25JUN14
1130	Install Rough Fire Sprinkler	40	40	0	09JUN14	04AUG14
1135	Install Utility Yard Gates	20	20	0	12JUN14	10JUL14
1525	Install Exterior Metal Panels	25	25	0	19JUN14	24JUL14
1150	Set/Install Electrical Gear & Equipment	40	40	0	26JUN14	21AUG14
1305	Set/Inst. Misc. Pumps, Fans & Equip.- Main Level	50	50	0	26JUN14	05SEP14
1295	Set/Install Heat Exchangers & Equi - Main Level	45	45	0	26JUN14	28AUG14
1315	Set/Install Water Conditioning - Main Level	45	45	0	26JUN14	28AUG14
1275	Inst. Air Compressors & Equip. - Main Level (AC)	30	30	0	26JUN14	07AUG14
1335	Set/Install Fuel Oil - Main Level	30	30	0	26JUN14	07AUG14
1285	Set/Install HRGS & Equip. - Main Level	50	50	0	01JUL14	10SEP14
1345	Set/Install AHU & RTU - Roof	30	30	0	03JUL14	14AUG14
1350	Install Smoke Stacks	30	30	0	03JUL14	14AUG14
1040	Install Overhead Bridge Crane	20	20	0	03JUL14	31JUL14
1515	Install Process Integration System	55	55	0	08JUL14	23SEP14
1265	Set/Install Steam Boilers - Main Level (PECO)	50	50	0	15JUL14	23SEP14
1495	Caulking	10	10	0	18JUL14	31JUL14
1585	Seal CMU	20	20	0	18JUL14	14AUG14
1035	Frame Interior Walls	10	10	0	22JUL14	04AUG14
1370	Pull Wire & Terminate Equipment	40	40	0	22JUL14	16SEP14



Start Date 15JUL13
Finish Date 29FEB16
Data Date 07NOV13
Run Date 08NOV13 11:25

Early Bar
Progress Bar
Critical Activity

BI03

Sheet 3 of 6

BYU-Idaho
Central Energy Facility
Additions & Upgrades
Status as of 07 November 2013

BYU IDAHO

BIG-D CONSTRUCTION

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
1120	Install In-drywall Rough Plumbing	20	20	0	22JUL14	18AUG14
1320	Install Mechancal/Pipe Insulation	70	70	0	25JUL14	31OCT14
1535	Install Exterior Architectural Louvers	10	10	0	25JUL14	07AUG14
1455	Set/Install & Install New Generator	60	60	0	29JUL14	21OCT14
1565	Install Interior Wall Batt Insulation	3	3	0	05AUG14	07AUG14
1290	Install Snowmelt Piping	25	25	0	08AUG14	12SEP14
1095	Hang & Finish Drywall	10	10	0	12AUG14	25AUG14
1365	Interior Paint	10	10	0	26AUG14	09SEP14
1605	Install Fire Caulking	5	5	0	26AUG14	02SEP14
1330	Chemical Treatment of Mechanical/Pipe System	12	12	0	08SEP14	23SEP14
1375	Install Mechanical & Plumbing Trim	10	10	0	10SEP14	23SEP14
1395	Install Electrical Lights & Trim	30	30	0	10SEP14	21OCT14
1475	Install Doors & Hardware	5	5	0	10SEP14	16SEP14
1415	Install Millwork/Cabinets & Counter Tops	3	3	0	10SEP14	12SEP14
1405	Install Fire Sprinkler Trim	15	15	0	10SEP14	30SEP14
1385	Install Plumbing Trim	20	20	0	15SEP14	10OCT14
1050	Start-up & Test Electrical Systems	30	30	0	17SEP14	28OCT14
1360	Paint Mechanical Lines	50	50	0	22SEP14	02DEC14
1160	Start-up & Test Mechanical Systems	30	30	0	24SEP14	04NOV14
1425	Seal Floors & Epoxy Coating	15	15	0	22OCT14	11NOV14
1595	Touch-up Painting of Structural Steel	20	20	0	22OCT14	18NOV14
1170	Commissioning & Balancing	60	60	0	05NOV14	02FEB15
1655	Process Integration System Commissioning	40	40	0	05NOV14	05JAN15
1575	Install Rubber Base	5	5	0	12NOV14	18NOV14
1355	Set CoGen Equipment - Main Level	5	5	0	01DEC14*	05DEC14
1435	Install CoGen Mechanical Duct	40	40	0	08DEC14	03FEB15
1505	Install CoGen Cooling Equipment	55	55	0	08DEC14	24FEB15
1615	Install CoGen Mechanical & Process Piping	55	55	0	08DEC14	24FEB15
1625	Install CoGen Rough Electrical Conduit	40	40	0	08DEC14	03FEB15
1635	Pull Wire & Terminate CoGen Equipment	30	30	0	14JAN15	24FEB15
1445	Start-up, Test & Commission COGen Equipment	30	30	0	25FEB15	07APR15
1055	Punchlist Inspections & Turn-over	10	10	0	04MAR15	17MAR15
1145	Relocate into New Facility	10	10	0	08APR15	21APR15
Phase 1B - Underground Utilities & Parking						
2145	Excavate South Electrical Vault	1	1	0	21MAY14	21MAY14
2060	Install 8" S Sewer Line 1st So to Sampling MH	5	5	0	21MAY14	28MAY14
2055	Form & Pour South Electrical Vault	10	10	0	22MAY14	05JUN14
2155	Excavate North Electrical Vault	1	1	0	22MAY14	22MAY14
2010	Install Water Line Accross 1st West	5	5	0	29MAY14	04JUN14
2070	Install Electrical Duct Bank - 1st West	5	5	0	06JUN14	12JUN14
2040	Install Electrical Duct Bank (Off-Site)	25	25	0	06JUN14	11JUL14
2065	Form & Pour North Electrical Vault	10	10	0	06JUN14	19JUN14
2047	Relocate Exsiting Fire Hydrant	3	3	0	19JUN14	23JUN14
2075	Install Gas Line	5	5	0	20JUN14	26JUN14
2130	Replace Curb & Gutter & Sidewalk 1st West	15	15	0	14JUL14	01AUG14
2135	Patch/Repaire Asphalt on 1st West	10	10	0	04AUG14	15AUG14
2000	Clear & Grub	5	5	0	23APR14	29APR14
2050	Demo North Steam Line	10	10	0	30APR14	13MAY14
2005	Excavate & Blast	5	5	0	14MAY14	20MAY14
2095	Install Chill S Line	10	10	0	21MAY14	04JUN14
2100	Install Chill R Line	10	10	0	21MAY14	04JUN14
2140	Set & Install Pre-cast Sand/Oil Interceptor	2	2	0	29MAY14	30MAY14
2045	Install Water Line with Fire Hydrant - On Site	10	10	0	05JUN14	18JUN14

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Early Bar
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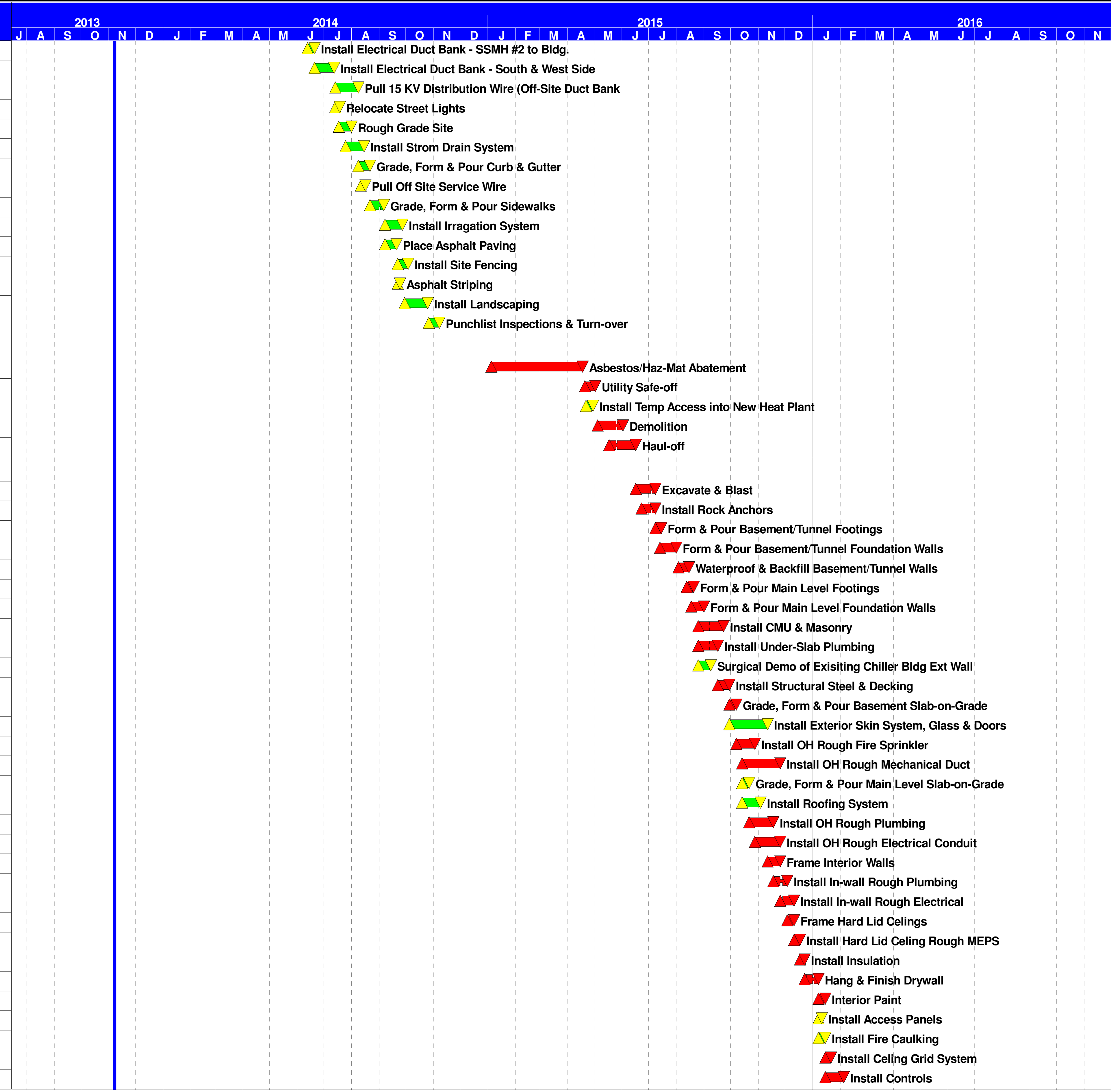
BYU-Idaho
Central Energy Facility
Additions & Upgrades
Status as of 07 November 2013

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
2085	Install Electrical Duct Bank - SSMH #2 to Bldg.	5	5	0	13JUN14	19JUN14
2090	Install Electrical Duct Bank - South & West Side	15	15	0	20JUN14	11JUL14
2160	Pull 15 KV Distribution Wire (Off-Site Duct Bank	20	20	0	14JUL14	08AUG14
2105	Relocate Street Lights	5	5	0	14JUL14	18JUL14
2015	Rough Grade Site	10	10	0	18JUL14	31JUL14
2080	Install Strom Drain System	15	15	0	25JUL14	14AUG14
2020	Grade, Form & Pour Curb & Gutter	10	10	0	08AUG14	21AUG14
2150	Pull Off Site Service Wire	5	5	0	11AUG14	15AUG14
2110	Grade, Form & Pour Sidewalks	10	10	0	22AUG14	05SEP14
2120	Install Irragation System	15	15	0	08SEP14	26SEP14
2025	Place Asphalt Paving	10	10	0	08SEP14	19SEP14
2035	Install Site Fencing	10	10	0	22SEP14	03OCT14
2115	Asphalt Striping	2	2	0	22SEP14	23SEP14
2125	Install Landscaping	20	20	0	29SEP14	24OCT14
2030	Punchlist Inspections & Turn-over	10	10	0	27OCT14	07NOV14
Phase 2A - Demo Existing Heat Plant						
3000	Asbestos/Haz-Mat Abatement	75	75	0	05JAN15*	17APR15
3005	Utility Safe-off	10	10	0	20APR15	01MAY15
3020	Install Temp Access into New Heat Plant	5	5	0	22APR15	28APR15
3010	Demolition	20	20	0	04MAY15	01JUN15
3015	Haul-off	20	20	0	18MAY15	15JUN15
Phase 2B - New Administration						
4000	Excavate & Blast	15	15	0	16JUN15	07JUL15
4280	Install Rock Anchors	10	10	0	23JUN15	07JUL15
4005	Form & Pour Basement/Tunnel Footings	5	5	0	08JUL15	14JUL15
4015	Form & Pour Basement/Tunnel Foundation Walls	15	15	0	13JUL15	31JUL15
4010	Waterproof & Backfill Basement/Tunnel Walls	10	10	0	03AUG15	14AUG15
4120	Form & Pour Main Level Footings	5	5	0	13AUG15	19AUG15
4125	Form & Pour Main Level Foundation Walls	10	10	0	18AUG15	31AUG15
4020	Install CMU & Masonry	20	20	0	25AUG15	22SEP15
4265	Install Under-Slab Plumbing	15	15	0	25AUG15	15SEP15
4110	Surgical Demo of Exisiting Chiller Bldg Ext Wall	10	10	0	25AUG15	08SEP15
4025	Install Structural Steel & Decking	10	10	0	16SEP15	29SEP15
4040	Grade, Form & Pour Basement Slab-on-Grade	5	5	0	30SEP15	06OCT15
4035	Install Exterior Skin System, Glass & Doors	30	30	0	30SEP15	10NOV15
4030	Install OH Rough Fire Sprinkler	15	15	0	07OCT15	27OCT15
4130	Install OH Rough Mechanical Duct	30	30	0	14OCT15	24NOV15
4050	Grade, Form & Pour Main Level Slab-on-Grade	5	5	0	14OCT15	20OCT15
4045	Install Roofing System	15	15	0	14OCT15	03NOV15
4135	Install OH Rough Plumbing	20	20	0	21OCT15	17NOV15
4140	Install OH Rough Electrical Conduit	20	20	0	28OCT15	24NOV15
4145	Frame Interior Walls	10	10	0	11NOV15	24NOV15
4150	Install In-wall Rough Plumbing	10	10	0	18NOV15	03DEC15
4155	Install In-wall Rough Electrical	10	10	0	25NOV15	10DEC15
4160	Frame Hard Lid Celings	5	5	0	04DEC15	10DEC15
4165	Install Hard Lid Celing Rough MEPS	5	5	0	11DEC15	17DEC15
4170	Install Insulation	3	3	0	18DEC15	22DEC15
4065	Hang & Finish Drywall	10	10	0	23DEC15	07JAN16
4070	Interior Paint	5	5	0	08JAN16	14JAN16
4115	Install Access Panels	2	2	0	08JAN16	11JAN16
4175	Install Fire Caulking	5	5	0	08JAN16	14JAN16
4185	Install Celing Grid System	5	5	0	15JAN16	21JAN16
4275	Install Controls	15	15	0	15JAN16	04FEB16



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Critical Activity

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BYU-Idaho
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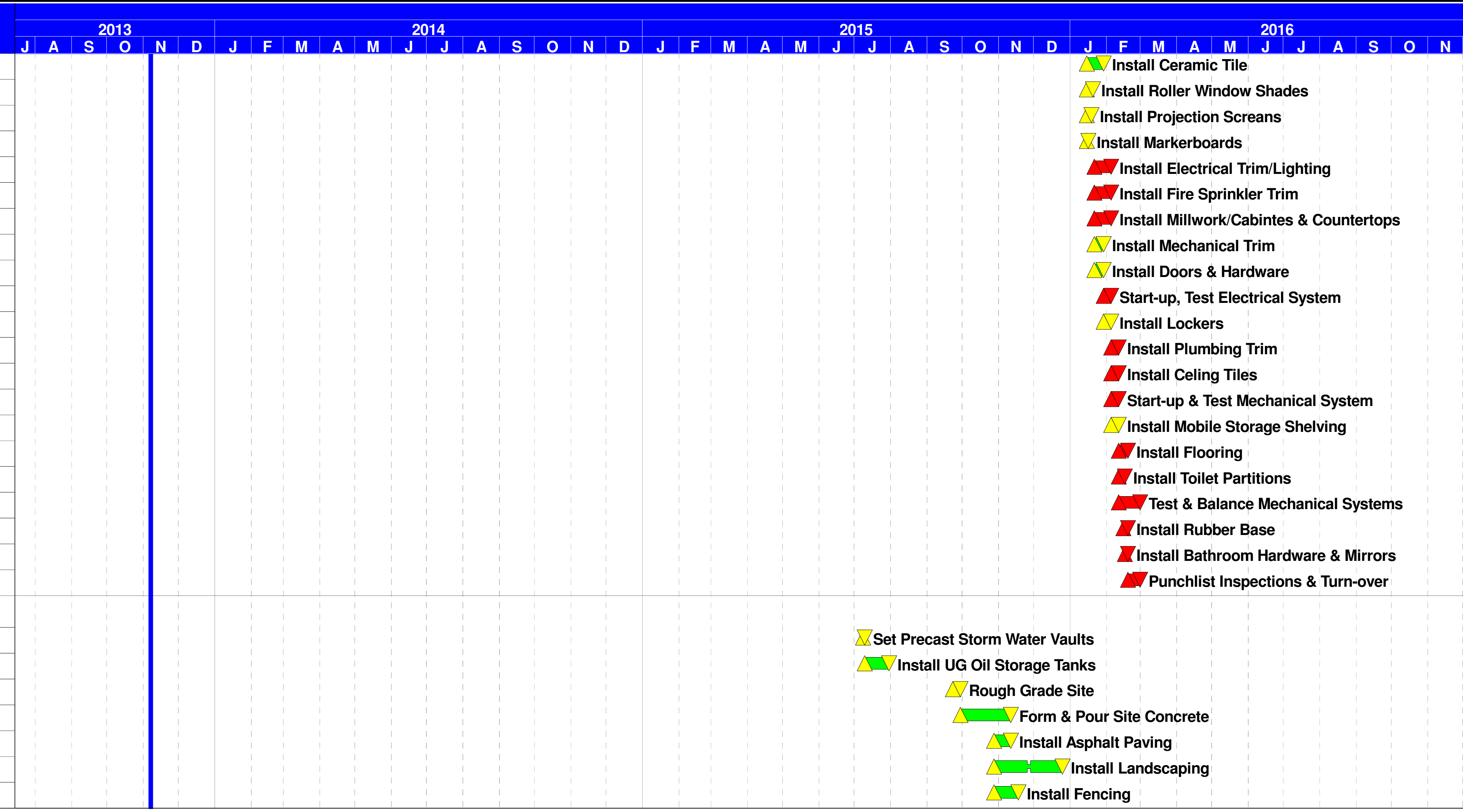
BYU IDAHO

BIG-D CONSTRUCTION

Activity ID	Activity Description	Orig Dur	Rem Dur	%	Early Start	Early Finish
4180	Install Ceramic Tile	10	10	0	15JAN16	28JAN16
4260	Install Roller Window Shades	3	3	0	15JAN16	19JAN16
4270	Install Projection Screans	2	2	0	15JAN16	18JAN16
4250	Install Markerboards	1	1	0	15JAN16	15JAN16
4190	Install Electrical Trim/Lighting	10	10	0	22JAN16	04FEB16
4195	Install Fire Sprinkler Trim	10	10	0	22JAN16	04FEB16
4205	Install Millwork/Cabintes & Countertops	10	10	0	22JAN16	04FEB16
4200	Install Mechanical Trim	5	5	0	22JAN16	28JAN16
4225	Install Doors & Hardware	5	5	0	22JAN16	28JAN16
4075	Start-up, Test Electrical System	5	5	0	29JAN16	04FEB16
4230	Install Lockers	5	5	0	29JAN16	04FEB16
4210	Install Plumbing Trim	5	5	0	05FEB16	11FEB16
4220	Install Celing Tiles	5	5	0	05FEB16	11FEB16
4285	Start-up & Test Mechanical System	5	5	0	05FEB16	11FEB16
4235	Install Mobile Storage Shelving	5	5	0	05FEB16	11FEB16
4215	Install Flooring	5	5	0	12FEB16	18FEB16
4240	Install Toilet Partitions	3	3	0	12FEB16	16FEB16
4295	Test & Balance Mechanical Systems	12	12	0	12FEB16	29FEB16
4255	Install Rubber Base	3	3	0	16FEB16	18FEB16
4245	Install Bathroom Hardware & Mirrors	2	2	0	17FEB16	18FEB16
4080	Punchlist Inspections & Turn-over	7	7	0	19FEB16	29FEB16
Phase 2B - Site Work						
4055	Set Precast Storm Water Vaults	2	2	0	08JUL15	09JUL15
4060	Install UG Oil Storage Tanks	15	15	0	10JUL15	30JUL15
4085	Rough Grade Site	5	5	0	23SEP15	29SEP15
4090	Form & Pour Site Concrete	30	30	0	30SEP15	10NOV15
4095	Install Asphalt Paving	10	10	0	28OCT15	10NOV15
4100	Install Landscaping	40	40	0	28OCT15	24DEC15
4105	Install Fencing	15	15	0	28OCT15	17NOV15



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BYU-Idaho
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BYU IDAHO

BIG-D CONSTRUCTION

TAB 16

PROPOSED EMISSIONS LIMITS AND MODELED AMBIENT CONCENTRATION FOR ALL REGULATED AIR POLLUTANTS

The updated dispersion model is available on Heath Engineering Company's FTP site at the following address:

ftp.heatheng.com

username: BYUIboiler2
password: emodel

The original dispersion model was given via disk and thumb drive to Cheryl A. Robinson on September 26, 2013.

The updated dispersion model is included on a disk and thumb drive as part of this application.

A copy of the dispersion model report is included in this tab.

Brigham Young University - Idaho
Boiler Replacement Project
Dispersion Modeling Report

Trinity Consultants, Inc. (Trinity) has prepared this dispersion modeling report on behalf of Brigham Young University - Idaho (BYUI). The report describes the dispersion modeling methodologies and model results analysis in support of a Permit-To-Construct (PTC) application for the proposed replacement of three (3) existing stoker coal-fired boilers with two (2) natural gas-fired boilers and one (1) combustion turbine with a Heat Recovery Steam Generator (HRSG). All of the new combustion units will utilize ultra-low sulfur diesel (ULSD) as backup fuel, except the HRSG, which is only capable of firing natural gas. An existing natural gas-fired boiler will also be relocated and a new combination natural gas and fuel oil burner installed as part of this project. Two new emergency generators will be added to the Heat Plant as part of this project.

Initially a significant impact analysis was conducted to determine whether emissions associated with the project would cause a significant impact upon the area surrounding the BYUI campus Heat Plant. Significant impacts were predicted for 1-hr NO_2, 24-hr PM_{10}, and 24-hr $PM_{2.5}$, necessitating a full National Ambient Air Quality Standards (NAAQS) compliance modeling evaluation for these pollutant averaging periods. The NAAQS analyses for these pollutant averaging periods showed no predicted exceedances of air quality standards. The modeling procedures used follow the Idaho Department of Environmental Quality (IDEQ) guidance[1] and the modeling protocol submitted to the Idaho Department of Environmental Quality (IDEQ).[2]

PROJECT DESCRIPTION

The proposed project includes replacement of the existing coal-fired Boilers No. 2, No. 3, and No. 4 at the BYUI campus Heat Plant with two new natural gas-fired boilers and a combustion turbine with a heat recovery steam generator (HRSG). BYUI will relocate existing Boiler No. 5 and install a new combination natural gas and oil burner on this boiler as part of the proposed project. The new burners will be of approximately the same heat input capacity as the existing burners. BYUI is requesting that the modified permit for Boiler No. 5 specify that ULSD is to be used when firing diesel fuel (in order to limit SO_2 emissions). Tables 1 and 2 depict the current and post-project BYUI Heat Plant boilers.

The proposed project includes removal of the existing permitted ash handling system at the Heat Plant. BYUI will not need the ash handling system after replacing the coal-fired boilers with natural gas-fired boilers. The proposed project also includes replacing one (1) 300 kW diesel-fired emergency engine generator with two (2) 500 kW diesel-fired emergency generators, to serve both the Heat Plant and campus. No changes are proposed to the two (2) existing 500 kW emergency generators serving the Auditorium present at the Heat Plant. Note that these two (2) 500 kW emergency generators have not been included in previous modeling evaluations and will also be excluded from the proposed significant impact modeling for the boiler replacement project based on discussion with IDEQ.[3]

In addition to the Heat Plant, BYUI currently has other emission units including twenty (20) emergency generators ranging in size from 5 kW to 438 kW and three (3) paint spray booths. The proposed project will not impact these emission units.

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[1] IDEQ, *State of Idaho Guideline for Performing Air Quality Impact Analyses*, Doc. I D AQ-011 (rev. 2 July 2011). Available at: http://www.deq.idaho.gov/media/355037-modeling-guideline.pdf

[2] Protocol submitted by Mr. Allan Oestmann (Trinity Consultants) to Ms. Cheryl Robinson (IDEQ), dated February 4, 2013. Protocol approval received from Ms. Cheryl Robinson on April 23, 2013.

[3] March 20, 2012, telephone call between Ms. Cheryl Robinson (IDEQ) and Mr. Allan Oestmann (Trinity Consultants).

Table 1. Existing BYUI Heat Plant Boilers

Boiler	Manufacturer	Model	Permitted Fuel(s)	Heat Input (MMBtu/hr)	Installation Date
Boiler No. 2	Erie City Iron Works	16792 H.S.B	Bituminous Coal	26.7	1963
Boiler No. 3	Union Iron Works	234-28	Bituminous Coal	40	1966
Boiler No. 4	Keeler	Watertube MK	Bituminous Coal	46.7	1973
Boiler No. 5	Indeck/Volcano	02-40-X	Natural Gas / No. 2 Oil	51 Gas / 48.25 Oil	2001

Table 2. Post-Project BYUI Heat Plant Configuration

Boiler	Emission Unit ID	Permitted Fuel(s)	Heat Input (MMBtu/hr)
Combustion Turbine	EU01	Natural Gas/ULSD	60
HRSG	EU01A	Natural Gas	30
Boiler No. 2	BLR2	Natural Gas/ULSD	55
Boiler No. 3	BLR3	Natural Gas/ULSD	55
Boiler No. 4	BLR4	Natural Gas/ULSD	50

MODELING REQUIREMENTS

BYUI is located in Rexburg (Lat. 43°49'23"N, Long. 111°47'7"W), the county seat of Madison County, Idaho. Madison County is currently designated by the United States Environmental Protection Agency (EPA) as "attainment" or "unclassifiable" for all criteria pollutants. Therefore, the Prevention of Significant Deterioration (PSD) program applies in Madison County. The proposed project will not exceed the PSD significant emission rates (Attachment 2), and therefore, PSD permitting is not required. For non-PSD modeling analyses, IDEQ regulations require an evaluation of impacts for National Ambient Air Quality Standards (NAAQS) compliance, beginning with a significant impact analysis. The following pollutants were modeled in this analysis:

- Particulate matter equal to or less than ten microns in aerodynamic diameter (PM_{10}),
- Particulate matter equal to or less than 2.5 microns in aerodynamic diameter ($PM_{2.5}$),
- Sulfur dioxide (SO_2),
- Nitrogen dioxide (NO_2), and
- Carbon monoxide (CO).

All of the new sources to be installed at BYUI are subject to either 40 CFR Part 60 (New Source Performance Standards), 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants (NESHAP)), or 40 CFR Part 63 (NESHAP for Source Categories / MACT standards). As described in the permit application, the boilers are subject to NSPS Subpart Dc, the new generators are subject to NSPS Subpart IIII, and the turbine and HRSG are subject to NSPS Subpart KKKK. Evaluation of compliance with the Idaho air toxics program was not performed because Section 210.20 of the Idaho Air Rules states that a demonstration of compliance with state-only toxic air pollutants (TAPs) is not required for any TAP that is regulated under 40 CFR Part 60 (New Source Performance Standards (NSPS)), 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants (NESHAP)), or 40 CFR Part 63 (NESHAP for Source Categories / MACT standards). Because all new units are subject to NSPS that regulate all state-only TAPs, no further demonstration of preconstruction compliance is required.

AIR QUALITY MODELING METHODOLOGY

IDEQ regulations require an evaluation of impacts for NAAQS compliance as part of the PTC application process, beginning with a significant impact analysis. The dispersion modeling analyses was conducted in accordance with the EPA's *Guideline on Air Quality Models*[4], EPA's *AERMOD Implementation Guide*[5] , and the IDEQ Modeling Guidelines.[6]

Significance Analysis

A significance analysis was performed to determine if the emissions increases associated with this project significantly impact the area surrounding the facility. The significance analysis was conducted for SO_2, NO_2, CO, PM_{10}, and $PM_{2.5}$. Modeled concentrations were compared to significant impact levels (SIL) established by the EPA and IDEQ. The SIL and corresponding NAAQS for the pollutants modeled are shown in Table 3.

The significant impact analysis was conducted for the project related sources only:

New Sources	**Existing sources**
Combustion Turbine	Boiler 2 (coal-fired)
HRSG	Boiler 3 (coal-fired)
Boiler 2	Boiler 4 (coal-fired)
Boiler 3	Boiler 5 (natural gas / oil-fired)
Boiler 4	
EG481	
EG482	
EF483	
EF484	

If the highest ambient concentration resulting from the modeled project emissions for a pollutant is less than the SIL, then further analyses are not required for that pollutant averaging time because the emissions will neither cause nor contribute to any exceedance of the NAAQS. If concentrations exceed the SIL, a NAAQS "Full Impacts Analysis" is required for that pollutant averaging time.

NAAQS Analysis

Primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of a pollutant in the atmosphere, which define the "levels of air quality which the EPA judges are necessary, with an adequate margin

[4] 40 CFR 51, Appendix W (Revised, November 9, 2005)
[5] Available at: http://www.epa.gov/ttn/scram/7thconf/aermod/aermod_implmtn_guide_19March2009.pdf.
[6] IDEQ, *State of Idaho Guideline for Performing Air Quality Impact Analyses*, Doc. I D AQ-011 (rev. 2 July 2011). Available at: http://www.deq.idaho.gov/media/355037-modeling-guideline.pdf

of safety, to protect the public health."[7] Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant."

The objective of the NAAQS analysis is to demonstrate through air quality modeling that emissions from the proposed project do not contribute to, or cause, an exceedance of the NAAQS at any ambient location. Table 3 depicts the NAAQS for each pollutant being evaluated in this modeling analysis.

A NAAQS analysis is required for pollutants with maximum concentrations that exceed the SIL. In the NAAQS analysis, the potential emissions from BYUI emission units at the Rexburg campus were modeled to determine impacts. The appropriate background concentrations were added to the modeled impact to predict the cumulative impact, which is then compared to the NAAQS to determine compliance. BYUI used background concentrations developed by IDEQ for the Rexburg area for each pollutant/averaging time. Note IDEQ has not required inclusion of offsite sources for BYUI NAAQS modeling analyses.

Each NAAQS includes a specific statistical form for demonstrating compliance with that NAAQS; that statistical form is relevant in both assigning background monitoring concentrations and modeled impact concentrations. The NO_2 annual NAAQS is the maximum annual average. The 1-hr NO_2 NAAQS uses the 98^{th} percentile of annual distribution of the daily maximum 1-hr concentrations. Modeling with five years of meteorological data with this form results in using the highest 8^{th} high (H8H) daily maximum concentration to demonstrate compliance with the 1-hr NO_2 NAAQS. The current version of AERMOD includes an output option to accommodate the NO_2 1-hr NAAQS.

IDEQ has deemed that due to the stringency of the 1-hr SO_2 NAAQS compared to the 3-hr and 24-hr standards, modeling of the 1-hr NAAQS is sufficient to demonstrate compliance with the 3-hr and 24-hr NAAQS.[8] Therefore, only the 1-hr and annual SO_2 NAAQS were analyzed.

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[7] 40 CFR 50.2(b).
[8] Email from Ms. Cheryl Robinson (IDEQ) to Mr. Allan Oestmann (Trinity Consultants) on January 14, 2013.

Table 3. Significant Levels and NAAQS

Pollutant	Averaging Time	Significant Impact Levels ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
CO	1-hour 8-hour	2,000 500	40,000[a] 10,000[a]
NO_2	1-hour Annual	7.5 [c] 1	188 [c] 100[d]
SO_2	1-hour 3-hour 24-hour Annual	7.9 [ce] 25 5 1	196[c] 1,300[a] 365[a] 80[d]
PM_{10}	24-hour	5	150[f]
$PM_{2.5}$	24-hour Annual	1.2 0.3	35 15

a. Not to be exceeded more than once per year.

b. Interim SIL (EPA 2010a)

c. $\mu g/m^3$ value calculated for standard conditions

d. Not to be exceeded in any calendar year.

e. Interim SIL (EPA 2010b)

f. Never expected to be exceeded more than once in any calendar year.

AIR QUALITY MODELING METHODOLOGY

This section of the modeling describes the specific modeling procedures and data resources utilized in the air quality modeling analyses. The techniques proposed for the air quality analyses are consistent with the current IDEQ guidance.

Selection of Model

The air quality modeling analyses were conducted using the **A**MS/**E**PA **R**egulatory **Mod**el (AERMOD), version 12345. AERMOD is a refined, steady state, multiple source, Gaussian dispersion model. For the pollutants evaluated, AERMOD utilized the default options except for 1-hr NO_2.

EPA recommends a three-tiered screening approach for modeling the 1-hr NO_2 NAAQS. Tier 1 is to assume full conversion of NO_x to NO_2. Tier 2 multiplies the Tier 1 concentration by the empirically derived NO_2/NO_x ratio, 0.8

(known as the Ambient Ratio Method, or ARM). Tier 3 involves use of the detailed screening methods known as the Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limiting Method (OLM). Use of PVMRM was approved by IDEQ. Both PVMRM and OLM account for ambient conversion of NO to NO_2 in the presence of ozone. The key inputs for PVMRM/OLM are in-stack NO_2/NO_x ratios and hourly ambient ozone concentrations. IDEQ approved the use of hourly ozone values for this analysis. In-stack NO_2/NO_x ratios of 10 percent for the natural gas-fired boilers, 5 percent for coal-fired boilers, and 20 percent for diesel-fired emergency generators were used.[9,] BYUI used a value of 75 percent for the equilibrium NO_2/NO_x ratio for all NO_2 sources as suggested by MACTEC.[10] This method is consistent with the ARM in the Guideline on Air Quality Models (40 CFR Part 51, Appendix W).

Receptor Grid and Coordinate System

For this air dispersion modeling analysis, ground-level concentrations were calculated using Cartesian receptor grids. The receptors were spaced as per IDEQ's modeling guidance and identically to previous BYUI modeling analyses:

- 25-meter grid covering an area with an East-West dimension of 1,075 m and a North-South dimension of 1,325 m centered on the BYUI campus.
- 50-meter grid extending 500 meters beyond the 25 meter grid.

Receptor elevations required by AERMOD were based on National Elevation Dataset (NED) data obtained from the United States Geological Survey National Map Seamless Server. AERMAP version 11103 was used to extract the elevations from the NED data to import terrain elevations for selected model objects and to generate the receptor hill height scale data that are used by AERMOD to drive advanced terrain processing algorithms.

As approved in the modeling protocol, the footprint of the campus buildings was utilized to define ambient air. Therefore, receptors that fall in the 25 meter, 50 meter, and 100 meter receptor grids that fall inside campus buildings were omitted from the model.

The locations of emission sources, structures, and receptors were represented in the Universal Transverse Mercator (UTM) coordinate system. The UTM grid divides the world into coordinates that are measured in north meters (measured from the equator) and east meters (measured from the central meridian of a particular zone, which is set at 500 km). The BYUI campus is approximately centered at UTM Zone 12, coordinates 437.1 km East and 4,851.9 km North using North American Datum 1983 (NAD 83).

Meteorological Data

Site-specific dispersion models require a sequential hourly record of dispersion meteorology representative of the region where the source is located. In the absence of site-specific measurements, the EPA guidelines recommend the use of readily available data from the closest and most representative National Weather Service (NWS) stations. Regulatory air quality modeling using AERMOD requires five years of quality-assured meteorological data that includes hourly records of the following parameters:

> Wind speed
> Wind direction
> Air temperature
> Micrometeorological Parameters (e.g., friction velocity, Monin-Obukhov length)
> Mechanical mixing height
> Convective mixing height

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[9] CAPCOA NO_2 Guidance Document, California Air Pollution Control Officers Association, October 27, 2011. Available at: http://www.valleyair.org/busind/pto/Tox_Resources/CAPCOANO2GuidanceDocument10-27-11.pdf

[10] Evaluation of Bias In AERMOD-PVMRM, MACTEC Federal Programs, Inc., June 2005. Available at: http://www.epa.gov/scram001/7thconf/aermod/pvmrm_bias_eval.pdf

The first three of these parameters are directly measured by monitoring equipment located at typical surface observation stations. The friction velocity, Monin-Obukhov length, and mixing heights are derived from characteristic micrometeorological parameters and from observed and correlated values of cloud cover, solar insolation, time of day and year, and latitude of the surface observation station. Surface observation stations form a relatively dense network, are normally found at airports, and are typically operated by the NWS. Upper air stations are fewer in number than surface observation points because the upper atmosphere is less vulnerable to local effects caused by terrain or other land influences and is therefore less variable. The NWS operates virtually all available upper air measurement stations in the United States.

Pre-processed meteorological data from the Rexburg Madison County Airport (WBAN 94194) surface and Boise (WBAN 24131) upper air stations was obtained from the IDEQ for the latest five-year period available. The pre-processed meteorological data included hourly averaged wind speed and wind direction data processed using 1-minute average wind data from the AERMINUTE wind data processor to supplement the standard hourly Automated Surface Observation System (ASOS) observations. The Rexburg surface station base elevation is 4,858 feet mean sea level elevation (1,480.7 meters).[11]

Building Downwash and GEP Analysis

AERMOD incorporates the Plume Rise Model Enhancements (PRIME) downwash algorithms. Direction specific building parameters required by AERMOD will be calculated using the BPIP-PRIME preprocessor (version 04274).

EPA has promulgated stack height regulations that restrict the use of stack heights in excess of "Good Engineering Practice" (GEP) in air dispersion modeling analyses. Under these regulations, that portion of a stack in excess of the GEP height is generally not creditable when modeling to determine source impacts. This essentially prevents the use of excessively tall stacks to reduce ground-level pollutant concentrations. The minimum stack height not subject to the effects of downwash, called the GEP stack height, is defined by the following:[12]

GEP stack height is the greater of:

- A height of 65 meters (approximately 213.25 feet) *de minimus* stack height measured from the ground level elevation at the base of the stack; or
- According to the formula $H_{GEP} = H + 1.5L$, where:

  H_{GEP} = minimum GEP stack height,

  H = structure height, and

  L = lesser dimension of the structure (height or projected width).

This equation is limited to stacks located within 5L of a structure, but not greater than 0.8 km (0.5 miles) from the stack. Stacks located at a distance greater than 5L are not subject to the wake effects of the structure. The wind direction-specific downwash dimensions and the dominant downwash structures used in this analysis are determined using BPIP. All BYUI source release heights are below the default value of 65 meters.

Representation of Emission Sources

Source Types

The AERMOD dispersion model allows emission units to be represented as point, area, or volume sources. For point sources with unobstructed vertical releases, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and exit velocity) in the modeling analyses. Per IDEQ policy, vertical sources with a rain cap, an exit velocity will be set to 0.001 m/s. All modeled sources will be represented as point sources in the model.

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[11] Base elevation listed in National Climatic Data Center station information at: http://www.ncdc.noaa.gov/cdo-web/datasets/GHCND/stations/GHCND:USW00094194/detail.

[12] 40 CFR 51.100(ii)

Source Emission Rates

Attachment 1 contains a list of the existing sources at the BYUI campus including source parameters and potential emission rates as modeled for the previous permit application submitted in 2009. The information in this table was verified and used in this modeling analysis without any changes. Note that equipment being replaced was removed from the model in the NAAQS analyses.

The boilers and generator to be replaced in this project were described previously. The new units' manufacturers have been determined, and the final source parameters were used for the new boilers and generators.

According to Section 6.3.1 of the IDEQ modeling guidelines, emissions from units being removed as part of the project should be modeled with negative emission rates in the significant impact analysis. Section 6.3.1 also states that permit-allowable emissions rates may be used for units that have an existing permit limit. The existing coal-fired boilers, ash handling system, and the emergency generator to be removed as part of this project have existing permit emission limits; therefore, these sources were modeled with negative emissions rates in the significance analysis. The proposed new boilers, the turbine, and the HRSG were modeled with emissions rates calculated using AP-42 emission factors. The new emergency generators were modeled with emission rates based on manufacturer data.

Attachment 2 presents the emission calculations for the new sources and compares the emission increase/decrease after the project is complete for the entire Rexburg campus. The annual hours of operation for each boiler and the HRSG shown in Attachment 2 are used only to calculate the total annual fuel use limit of 1034 x 10^6 ft^3/yr of natural gas and 472 x 10^3 gal/yr of ULSD (for the boilers and HRSG).

In addition, the following information was incorporated into the facility-wide NAAQS analyses:

- The Bypass stack operates when the turbine is in operation without the HRSG.
- The exit temperature and volume flow rates (and thus the exit velocity) of Boiler 5 reflect the results of stack testing performed in 2006.
- SO_2 emission rates reflect the use of ULSD fuel with a maximum sulfur content level of 15 ppm by weight.
- Manufacturer's data was utilized for the stack parameters and emission rates for the four generators not previously modeled. These include the two existing 500 kW generators serving the Auditorium and the two new 500 kW generators that will serve the Heat Plant (replacing the existing 300 kW Heat Plant generator).
- Per IDEQ policy, exit temperatures for all existing generators, other than the Clarke Building, are assumed to be 600°F, a low temperature for an engine exhaust, and therefore conservative. Design volume flow and temperature is available for the Clarke Building emergency generator; therefore, this data was input to the model.
- The Substation and Portable emergency generators were not included in the model. The Portable Generator is sited in various locations as needed and is a mobile, non-road engine. The Substation Generator is not located near the campus and for this reason is unlikely to contribute to impacts from the other BYUI sources.
- The Kimball Building emergency generator has a horizontally oriented stack. Per IDEQ policy, the actual stack diameter (eight inches) and exit velocity (57.6 meters per second) was input to the model based on calculations for the previous modeling submittal showing that buoyancy will dominate plume rise under all stability conditions for the Kimball Building emergency generator, allowing the use of the actual diameter and exit velocity. This methodology was applied to the Kimball Building emergency generator only.
- The emission rates of the BYUI generators were adjusted to reflect limited operation. IDEQ is primarily interested in situations in which the emergency electrical generators are operated for testing and maintenance, i.e., when other BYUI sources (namely, the boilers and turbine / HRSG) are in operation. Normal testing and maintenance operation occurs one day per month, and will be limited to half hour periods only during daylight hours. The emergency generators are permitted to operate up to 400 hours per year. The generator emission rates in the annual averaging period models will be adjusted by multiplying the allowable emission rates of the emergency generators by 400/8760 (0.0457). For short-term (24 hours or shorter) averaging periods the emission rates for NAAQS are set equal to half the maximum permitted lb/hr emission rates, to reflect the half hour limit on operations for testing and maintenance. IDEQ required additional modeling of short-term averaging periods using the half hour emission rates for twelve randomly selected hours, one for each month, to reflect the once a month half hour testing and maintenance limitation. IDEQ provided the methodology and an existing Excel

spreadsheet prepared to make the selection of hours when the generators run. Three sets of randomly selected hours were modeled with each generator limited to operation during the randomly selected hour for each month in the five year meteorological data set. Because only one generator is allowed to operate at a time for testing, and because BYUI desires maximum operational flexibility, every possible combination of boilers, turbine, HRSG was modeled as a source group in each of the model executions.

Rural/Urban Option

The AERMOD model allows the user to incorporate the effects of increased surface heating from an urban area on pollutant dispersion under stable atmospheric conditions. The Rexburg area does not have sufficient population to be considered "urban" for modeling purposes; therefore, none of the sources included in the model utilized the urban option.

Modeling Results

Significant Impact Analysis

Model results for the significant impact analysis are in Table 3. The maximum (H1H) predicted concentrations for CO 1-hour and 8-hour averaging periods, and SO_2 1-hour and annual averaging periods were below the significant impact thresholds. All modeling files, including building downwash, and AERMAP terrain processor program input and output listings are contained in the electronic files accompanying this report

The H1H concentration for 1-hour CO was 161.61 μg/m^3 compared to the significant impact threshold of 2,000 μg/m^3, while the 8-hour H1H concentration was 131.56 μg/m^3 compared to the significant impact threshold of 500 μg/m^3. Both CO H1H concentrations occur during operation of the Bypass stack while combusting natural gas.

The H1H concentration for 1-hour SO_2 was 2.76 μg/m^3 compared to the significant impact threshold of 7.9 μg/m^3, while the annual H1H concentration was 0.03 μg/m^3 compared to the significant impact concentration of 1.0 μg/m^3. Both SO_2 H1H concentrations occur during operation of the HRSG stack while combusting ULSD.

Table 4. Significant Impact Modeling Results

Pollutant	Averaging Time	Significant Impact Levels (μg/m^3)	Predicted Concentration (μg/m^3)
CO	1-hour 8-hour	2000 500	111.78 99.97
SO_2	1-hour Annual	7.9 1	1.72 0.00

Because the concentrations for CO and SO_2 for only the project sources and sources being removed were below the significant impact levels, no further modeling was conducted for these pollutant averaging periods. Predicted concentrations for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$, and 24-hour PM_{10} were above the significant impact levels, so the new sources were modeled with the rest of the campus sources to demonstrate NAAQS compliance.

NAAQS Results

Model results for the NAAQS modeling are shown in Table 5. NAAQS modeling included all BYUI campus sources. The maximum predicted design concentrations for the PM_{10} annual and 24-hr averaging periods, NO_2 1-hour and annual averaging periods, and $PM_{2.5}$ 24-hour and annual averaging periods were modeled and background concentrations approved by IDEQ were added to demonstrate compliance with NAAQS.[13]

The predicted concentration for 1-hour NO_2 was 69.3 μg/m^3 with the turbine/HRSG stack is in operation on ULSD and results from concentrations when the turbine/HRSG combines with concentrations from either the Benson building emergency generator or Austin building emergency generator. Adding the background concentration of 73 g/m^3 results in a total concentration of 142.3 μg/m^3 compared to the NAAQS of 188 μg/m^3.

The predicted concentration for annual NO_2 was 41.34 μg/m^3. Adding the background concentration of 17 μg/m^3 results in a total concentration of 58.34 μg/m^3 compared to the NAAQS of 100 μg/m^3. The predicted concentration occurs when using the turbine/HRSG stack on natural gas.

The predicted concentration for 24-hour $PM_{2.5}$ was 10.39 μg/m^3 and results when running Boiler No. 2, Boiler No. 3, and Boiler No. 4 in combination with EG483. Adding the background concentration of 19.3 μg/m^3 results in a total concentration of 29.69 μg/m^3 compared to the NAAQS of 35 μg/m^3. The predicted concentration occurs when the turbine/HRSG stack is in operation.

The predicted concentration for annual $PM_{2.5}$ was 4.29 μg/m^3. Adding the background concentration of 6.3 μg/m^3 results in a total concentration of 10.65 μg/m^3 compared to the NAAQS of 12 μg/m^3. The predicted concentration occurs when the turbine/HRSG stack is operating on ULSD.

The predicted concentration for 24-hour PM_{10} was 18.02 μg/m^3 and results when running Boiler No. 2, Boiler No. 3, and Boiler No. 4 with any of the emergency generators. Adding the background concentration of 81 μg/m^3 results in a total concentration of 99.02 μg/m^3 compared to the NAAQS of 150 μg/m^3. The predicted concentration occurs when the turbine/HRSG stack is operating on ULSD.

[13] Protocol submitted by Mr. Allan Oestmann (Trinity Consultants) to Ms. Cheryl Robinson (IDEQ), dated February 4, 2013. Protocol approval received from Ms. Cheryl Robinson on April 23, 2013.

Table 5. NAAQS Modeling Results

Pollutant	Averaging Time	NAAQS (µg/m³)	Predicted Concentrations (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)
NO_2	1-hour	188	69.3	73	142.3
	Annual	100	41.34	17	58.34
PM_{10}	24-hour	150	18.02	81	99.02
$PM_{2.5}$	24-hour	35	10.39	19.3	29.69
	Annual	15	4.35	6.3	10.65

TAB 17

RESTRICTIONS ON A SOURCE'S POTENTIAL TO EMIT

The information requested in this section is included in the permit to construct under Tab 9. This information was also submit earlier via email and hard copy to Darrin Pampaian, September 12, 2013.

TAB 18

Idaho Rules and Regulations Applicable to This Permit to Construct

IDAPA Section	Title
58.01.01.130	Startup, Shutdown, Scheduled Maintenance, Safety Measures, Upset and Breakdown
58.01.01.131	Excess Emissions
58.01.01.133	Startup, Shutdown and Scheduled Maintenance Requirements
58.01.01.135	Excess Emission Reports
58.01.01.157	Test Methods and Procedures
58.01.01.161	Toxic Substances
58.01.01.200	Procedures and Requirements for Permits to Construct
58.01.01.201	Permit to Construct Required
58.01.01.202	Application Procedures
58.01.01.203	Permit Requirements for New and Modified Stationary Sources
58.01.01.212	Obligation to Comply
58.01.01.213	Pre-Permit Construction
58.01.01.223	Exemption Criteria and Reporting Requirements for Toxic Air Pollutant Emissions
58.01.01.224	Permit To Construct Application Fee
58.01.01.225	Permit To Construct Permit Processing Fee
58.01.01.226	Payment of Fees for Permits To Construct
58.01.01.576	General Provisions for Ambient Air Quality Standards
58.01.01585	Toxic Air Pollutants Non-Carcinogenic Increments
58.01.01.590	New Source Performance Standards
8.01.01.591	National Emission Standards for Hazardous Air Pollutants
58.01.0.1.625	Visible Emissions
58.01.01.675	Fuel Burning Equipment – Particulate Matter
58.01.01.676	Standards for New Sources
58.01.01.725	Rules for Sulfur Content of Fuels

Federal Environment and Safety Codified Regulations
TITLE 40—Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

SUBPART Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source Notes

Source: 42 U.S.C. 7401–7601.

§ 60.40c Applicability and delegation of authority.

60.40c(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).

Brigham Young University – Idaho (BYUI)is proposing to construct three new 55 MMBtu/hr natural gas-fired boilers with distillate oil backup fuel. BYUI is therefore affected by this subpart.

60.40c(b)

In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

60.40c(c)

Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ § 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

60.40c(d)

Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

60.40c(e)

Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

BYUI proposes to install a 30 MMBtu/hr heat recovery steam generator (HRSG) with supplemental duct firing on natural gas only in association with a 40 MMBtu/hr combustion turbine. The HRSG is subject to subpart KKKK of this part.

60.40c(f)

Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

60.40c(g)

Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

60.40c(h)

Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

60.40c(i)

Temporary boilers are not subject to this subpart.

[72 FR page 32759, June 13, 2007, as amended at 74 FR page 5090, Jan. 28, 2009; 77 FR page 9461, Feb. 16, 2012]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.*, the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other

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sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

BYUI has read and understands these definitions and used them in providing this regulatory analysis.

[72 FR page 32759, June 13, 2007, as amended at 74 FR page 5090, Jan. 28, 2009; 77 FR page 9461, Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO_2).

60.42c(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.

BYUI is subject to this standard when firing oil and has provided a documented emission inventory which shows compliance.

60.42c(b)

Except as provided in paragraphs (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

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owner or operator of an affected facility that:

60.42c(b)(1)

Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

60.42c(b)(1)(i)

Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

60.42c(b)(1)(ii)

Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

60.42c(b)(2)

Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

60.42c(b)(2)(i)

Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

60.42c(b)(2)(ii)

Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

60.42c(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, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

60.42c(c)(1)

Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

Percent reduction requirement are not applicable to boilers with a maximum heat input capacity of 55 MMBtu/hr.

60.42c(c)(2)

Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

60.42c(c)(3)

Affected facilities located in a noncontinental area; or

60.42c(c)(4)

Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

60.42c(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.

BYUI will utilize ultra low sulfur diesel (ULSD) oil as backup fuel for these boilers. ULSD has maximum 0.000015 percent weight sulfur.

60.42c(e)

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, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

60.42c(e)(1)

The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

60.42c(e)(1)(i)

Combusts coal in combination with any other fuel;

60.42c(e)(1)(ii)

Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

60.42c(e)(1)(iii)

Has an annual capacity factor for coal greater than 55 percent (0.55); and

60.42c(e)(2)

The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s= SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a= 520 ng/J (1.2 lb/MMBtu);

K_b= 260 ng/J (0.60 lb/MMBtu);

K_c= 215 ng/J (0.50 lb/MMBtu);

H_a= Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b= Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c= Heat input from the combustion of oil, in J (MMBtu).

60.42c(f)

Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

60.42c(f)(1)

Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

60.42c(f)(2)

Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

60.42c(g)

Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

60.42c(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.

60.42c(h)(1)

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

60.42c(h)(2)

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

60.42c(h)(3)

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

60.42c(h)(4)

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

60.42c(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.

60.42c(j)

For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR page 32759, June 13, 2007, as amended at 74 FR page 5090, Jan. 28, 2009; 77 FR page 9462, Feb. 16, 2012]

§ 60.43c Standard for particulate matter (PM).

60.43c(a)

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 commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels 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 contain PM in excess of the following emission limits:

60.43c(a)(1)

22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

60.43c(a)(2)

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43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

60.43c(b)

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 commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) 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 contain PM in excess of the following emissions limits:

60.43c(b)(1)

43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

60.43c(b)(2)

130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

60.43c(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).

These boilers are subject to this standard when firing ULSD and has provided a documented emission inventory which shows compliance.

60.43c(d)

The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

60.43c(e)

60.43c(e)(1)

On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7

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MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

60.43c(e)(2)

As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. 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 commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

60.43c(e)(2)(i)

22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

60.43c(e)(2)(ii)

0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

60.43c(e)(3)

On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis 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 contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

60.43c(e)(4)

An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR page 32759, June 13, 2007, as amended at 74 FR page 5091, Jan. 28, 2009; 77 FR page 9462, Feb. 16, 2012]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

60.44c(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.

60.44c(b)

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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.

60.44c(c)

After the initial performance test required under paragraph (b) of this section and § 60.8, compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

60.44c(d)

If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

60.44c(e)

If coal, oil, or coal and oil are combusted with other fuels:

60.44c(e)(1)

An adjusted E_{ho}(E_{ho}o) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E_{ao}(E_{ao}o). The E_{ho}o is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

E_{ho}o = Adjusted E_{ho}, ng/J (lb/MMBtu);

E_{ho}= Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w= 0.

X_k= Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

60.44c(e)(2)

The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

60.44c(f)

Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

60.44c(f)(1)

If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$= Potential SO_2 emission rate, in percent;

$\%R_g$= SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

60.44c(f)(2)

If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

60.44c(f)(2)(i)

To compute the $\%P_s$, an adjusted $\%R_g$($\%R_g$o) is computed from E_{ao}o from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai}o) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E^o_{ao}}{E^o_{ai}}\right)$$

Where:

$\%R_g$o = Adjusted $\%R_g$, in percent;

E_{ao}o = Adjusted E_{ao}, ng/J (lb/MMBtu); and

E_{ai}o = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

60.44c(f)(2)(ii)

To compute E_{ai}o, an adjusted hourly SO_2 inlet rate (E_{hi}o) is used. The E_{hi}o is computed using the following formula:

$$E_{hi}o = \frac{E_{hi} - E_w (1 - X_k)}{X_k}$$

Where:

$E_{hi}o$ = Adjusted E_{hi}, ng/J (lb/MMBtu);

E_{hi}= Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w= 0; and

X_k= Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

60.44c(g)

For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

BYUI opts to use this method to demonstrate compliance with the SO2 standard.

60.44c(h)

For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

60.44c(i)

The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

60.44c(j)

The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

60.45c(a)

The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

60.45c(a)(1)

Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

60.45c(a)(2)

Method 3A or 3B of appendix A–2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A–3 of this part or 17 of appendix A–6 of this part.

60.45c(a)(3)

Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

60.45c(a)(3)(i)

Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

60.45c(a)(3)(ii)

Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 ° C (320 ° F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

60.45c(a)(3)(iii)

Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

60.45c(a)(4)

The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

60.45c(a)(5)

For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ± 14 ° C (320± 25 ° F).

60.45c(a)(6)

For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

60.45c(a)(7)

For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

60.45c(a)(7)(i)

The O_2 or CO_2 measurements and PM measurements obtained under this section,

60.45c(a)(7)(ii)

The dry basis F factor, and

60.45c(a)(7)(iii)

The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

60.45c(a)(8)

Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

60.45c(b)

The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

60.45c(c)

In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

60.45c(c)(1)

Notify the Administrator 1 month before starting use of the system.

60.45c(c)(2)

Notify the Administrator 1 month before stopping use of the system.

60.45c(c)(3)

The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

60.45c(c)(4)

The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

60.45c(c)(5)

The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

60.45c(c)(6)

Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

60.45c(c)(7)

At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

60.45c(c)(7)(i)

At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

60.45c(c)(7)(ii)

[Reserved]

60.45c(c)(8)

The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

60.45c(c)(9)

All valid CEMS data shall be used in calculating average emission concentrations even if the minimum

CEMS data requirements of paragraph (c)(7) of this section are not met.

60.45c(c)(10)

The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

60.45c(c)(11)

During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

60.45c(c)(11)(i)

For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

60.45c(c)(11)(ii)

For O2 (or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

60.45c(c)(12)

Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

60.45c(c)(13)

When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

60.45c(c)(14)

As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

60.45c(d)

The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR page 32759, June 13, 2007, as amended at 74 FR page 5091, Jan. 28, 2009; 76 FR page 3523, Jan. 20, 2011; 77 FR page 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

60.46c(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_2 concentrations 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.

60.46c(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.

60.46c(c)

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

60.46c(c)(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.

60.46c(c)(2)

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

60.46c(c)(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_2 emission rate of the fuel combusted, and the span value of the SO_2CEMS 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.

60.46c(c)(4)

For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO_2CEMS 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.

60.46c(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.

60.46c(d)(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.

60.46c(d)(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.

60.46c(d)(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).

60.46c(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.

60.46c(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.

§ 60.47c Emission monitoring for particulate matter.

60.47c(a)

Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

60.47c(a)(1)

Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

60.47c(a)(1)(i)

If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

60.47c(a)(1)(ii)

If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

60.47c(a)(1)(iii)

If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

60.47c(a)(1)(iv)

If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

60.47c(a)(2)

If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

60.47c(a)(2)(i)

The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

60.47c(a)(2)(ii)

If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

60.47c(a)(3)

If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

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60.47c(b)

All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

60.47c(c)

Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

60.47c(d)

Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

60.47c(e)

Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

60.47c(e)(1)

You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

60.47c(e)(1)(i)

The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

60.47c(e)(1)(ii)

Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

60.47c(e)(1)(iii)

At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

60.47c(e)(1)(iv)

Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

60.47c(e)(2)

You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

60.47c(e)(3)

You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

60.47c(e)(4)

You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

60.47c(f)

An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

60.47c(f)(1)

The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

60.47c(f)(2)

The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

60.47c(f)(3)

The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in § § 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

[72 FR page 32759, June 13, 2007, as amended at 74 FR page 5091, Jan. 28, 2009; 76 FR page 3523, Jan. 20, 2011; 77 FR page 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

60.48c(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:

60.48c(a)(1)

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

60.48c(a)(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.

60.48c(a)(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.

60.48c(a)(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.

60.48c(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.

60.48c(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.

60.48c(c)(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.

60.48c(c)(1)(i)

Dates and time intervals of all opacity observation periods;

60.48c(c)(1)(ii)

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

60.48c(c)(1)(iii)

Copies of all visible emission observer opacity field data sheets;

60.48c(c)(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.

60.48c(c)(2)(i)

Dates and time intervals of all visible emissions observation periods;

60.48c(c)(2)(ii)

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

60.48c(c)(2)(iii)

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

60.48c(c)(2)(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.

60.48c(c)(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

60.48c(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.

60.48c(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.

60.48c(e)(1)

Calendar dates covered in the reporting period.

60.48c(e)(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.

60.48c(e)(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.

60.48c(e)(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.

60.48c(e)(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.

60.48c(e)(6)

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

60.48c(e)(7)

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

60.48c(e)(8)

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

60.48c(e)(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.

60.48c(e)(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.

60.48c(e)(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.

60.48c(f)

Fuel supplier certification shall include the following information:

60.48c(f)(1)

For distillate oil:

60.48c(f)(1)(i)

The name of the oil supplier;

60.48c(f)(1)(ii)

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

60.48c(f)(1)(iii)

The sulfur content or maximum sulfur content of the oil.

60.48c(f)(2)

For residual oil:

60.48c(f)(2)(i)

The name of the oil supplier;

60.48c(f)(2)(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;

60.48c(f)(2)(iii)

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

60.48c(f)(2)(iv)

The method used to determine the sulfur content of the oil.

60.48c(f)(3)

For coal:

60.48c(f)(3)(i)

The name of the coal supplier;

60.48c(f)(3)(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);

60.48c(f)(3)(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

60.48c(f)(3)(iv)

The methods used to determine the properties of the coal.

60.48c(f)(4)

For other fuels:

60.48c(f)(4)(i)

The name of the supplier of the fuel;

60.48c(f)(4)(ii)

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

60.48c(f)(4)(iii)

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

60.48c(g)

60.48c(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.

60.48c(g)(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.

60.48c(g)(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.

60.48c(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.

60.48c(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.

60.48c(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.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Federal Environment and Safety Codified Regulations
TITLE 40—Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

SUBPART IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source Notes

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

60.4200(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.

60.4200(a)(1)

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

60.4200(a)(1)(i)

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

Brigham Young University – Idaho (BYUI) is proposing to construct two 671 horsepower CI ICE as part of the boiler replacement project. BYUI is therefore affected by this subpart.

60.4200(a)(1)(ii)

The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

60.4200(a)(2)

Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

60.4200(a)(2)(i)

Manufactured after April 1, 2006, and are not fire pump engines, or

60.4200(a)(2)(ii)

Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

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60.4200(a)(3)

Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

60.4200(a)(4)

The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

60.4200(b)

The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

60.4200(c)

If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 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 applicable to area sources.

60.4200(d)

Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

60.4200(e)

Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[Amended at 76 FR page 37967, June 28, 2011]

Emission Standards for Manufacturers

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

60.4201(a)

Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

60.4201(b)

Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-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 to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

60.4201(c)

Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-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 to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

60.4201(d)

Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE 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:

60.4201(d)(1)

Their 2007 model year through 2012 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;

60.4201(d)(2)

Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

60.4201(d)(3)

Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

60.4201(e)

Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

60.4201(e)(1)

Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

60.4201(e)(2)

Their 2014 model year and later 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.

60.4201(f)

Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

60.4201(f)(1)

Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

60.4201(f)(2)

Marine offshore installations.

60.4201(g)

Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[Amended at 76 FR page 37967, June 28, 2011]

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

60.4202(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.

60.4202(a)(1)

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

60.4202(a)(1)(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

60.4202(a)(1)(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.

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60.4202(a)(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.

60.4202(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.

60.4202(b)(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.

60.4202(b)(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.

60.4202(c)

[RESERVED]

60.4202(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.

60.4202(e)

Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE 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:

60.4202(e)(1)

Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

60.4202(e)(2)

Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

60.4202(e)(3)

Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

60.4202(e)(4)

Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

60.4202(f)

Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

60.4202(f)(1)

Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

60.4202(f)(2)

Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

60.4202(g)

Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

60.4202(g)(1)

Areas of Alaska not accessible by the FAHS; and

60.4202(g)(2)

Marine offshore installations.

60.4202(h)

Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[Amended at 76 FR page 37968, June 28, 2011]

§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in § 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR page 37968, June 28, 2011]

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

60.4204(a)

Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder 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 must comply with the emission standards in 40 CFR 94.8(a)(1).

The two CI ICE being installed as part of the boiler replacement project at BYUI must comply with the emission standards in 40 CFR 94.8(a)(1).

60.4204(b)

Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

The two CI ICE being installed as part of the boiler replacement project at BYUI must comply with the emission standards in 40 CFR 94.8(a)(1).

60.4204(c)

Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

60.4204(c)(1)

For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

60.4204(c)(1)(i)

17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

60.4204(c)(1)(ii)

$45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/ HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

60.4204(c)(1)(iii)

9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

60.4204(c)(2)

For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

60.4204(c)(2)(i)

14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

60.4204(c)(2)(ii)

$44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

60.4204(c)(2)(iii)

7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

60.4204(c)(3)

For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

60.4204(c)(3)(i)

3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

60.4204(c)(3)(ii)

$9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

60.4204(c)(3)(iii)

2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

60.4204(c)(4)

Reduce particulate matter (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).

60.4204(d)

Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

60.4204(e)

Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[Amended at 76 FR page 37968, June 28, 2011]

§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?

60.4205(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 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).

The two CI ICE being installed as part of the boiler replacement project at BYUI must comply with the emission standards in Table 1 of this subpart.

60.4205(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.

The two CI ICE being installed as part of the boiler replacement project at BYUI must comply with the emission standards in § 60.4202.

60.4205(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.

60.4205(d)

Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

60.4205(d)(1)

For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

§60.4205(d)(1) is not applicable because these engines are being installed after January 1, 2012.

60.4205(d)(1)(i)

17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

60.4205(d)(1)(ii)

$45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

60.4205(d)(1)(iii)

9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

60.4205(d)(2)

For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

60.4205(d)(2)(i)

14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

60.4205(d)(2)(ii)

$44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

60.4205(d)(2)(iii)

7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

60.4205(d)(3)

Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

60.4205(e)

Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

60.4205(f)

Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[Amended at 76 FR page 37969, June 28, 2011]

§ 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 over the entire life of the engine.

The two engines being installed as part of the boiler replacement project must comply the emission standards in §60.5204 and 60.4205 over the entire life of the engine.

[76 FR page 37969, June 28, 2011]

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?

60.4207(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).

The two engines being installed as part of the boiler replacement project must use diesel fuel that meets the requirements in in 40 CFR 80.510(a).

60.4207(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, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

60.4207(c)

[RESERVED]

60.4207(d)

Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

60.4207(e)

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

[Amended at 76 FR page 37969, June 28, 2011; 78 FR page 6695, Jan. 30, 2013]

Other Requirements for Owners and Operators

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

60.4208(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.

60.4208(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.

60.4208(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.

60.4208(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.

60.4208(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.

60.4208(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.

60.4208(g)

After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

60.4208(h)

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 (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

60.4208(i)

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.

[Amended at 76 FR page 37969, June 28, 2011]

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

<u>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.</u>

<u>**The two emergency diesel generators being installed as part of the boiler replacement project must meet the monitoring requirements specified in § 60.4211.**</u>

60.4209(a)

If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

60.4209(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.

[Amended at 76 FR page 37969, June 28, 2011]

Compliance Requirements

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

60.4210(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.

60.4210(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 (e) and § 60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

60.4210(c)

Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 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, 40 CFR part 94 or 40 CFR part 1042 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.

60.4210(c)(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.

60.4210(c)(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:

60.4210(c)(2)(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.

60.4210(c)(2)(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.

60.4210(c)(2)(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.

60.4210(c)(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.

60.4210(c)(3)(i)

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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 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

60.4210(c)(3)(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 40 CFR parts 89, 94, 1039 or 1042, 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.

60.4210(c)(3)(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.

60.4210(d)

An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 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.

60.4210(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.

60.4210(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.

60.4210(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”.

60.4210(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.

60.4210(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.

[Amended at 76 FR page 37969, June 28, 2011]

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

60.4211(a)

If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

60.4211(a)(1)

Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

60.4211(a)(2)

Change only those emission-related settings that are permitted by the manufacturer; and

60.4211(a)(3)

Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

BYUI must comply with the emission standards specified in this subpart, operate and maintain the CI ICE and control device according to the manufacturer's emission-related written instructions, change only those emission-related settings that are permitted by the manufacturer, and meet the requirements of 40 CFR parts 89, 94, and/or 1068 as applicable.

60.4211(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.

60.4211(b)(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.

60.4211(b)(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.

60.4211(b)(3)

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

60.4211(b)(4)

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

60.4211(b)(5)

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

60.4211(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 emission-related specifications, except as permitted in paragraph (g) of this section.

The two engines being installed as part of the boiler replacement project newer than the 2007 model year and are certified to the emissions standards in § 60.4204(b) or § 60.4205(b) or (c) as applicable.

60.4211(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.

60.4211(d)(1)

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

60.4211(d)(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.

60.4211(d)(2)(i)

Identification of the specific parameters you propose to monitor continuously;

60.4211(d)(2)(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;

60.4211(d)(2)(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;

60.4211(d)(2)(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

60.4211(d)(2)(v)

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

BYUI will conduct the initial performance test to demonstrate initial compliance with the emission standards, establish operating parameters to monitored continuously, identify the specific parameters to monitored continuously, provide discussion the relationship between these parameters and NOx and PM emissions, establish the upper and lower values for these parameters, identify the methods and and instruments used to monitor these parameters.

60.4211(d)(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.

60.4211(e)

If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

60.4211(e)(1)

Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

60.4211(e)(2)

Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

60.4211(f)

If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

BYUI will operate the engines as emergency stationary ICE, and will operate in non-emergency situations for less than 50 hours per year, including testing and maintenance.

60.4211(f)(1)

There is no time limit on the use of emergency stationary ICE in emergency situations.

60.4211(f)(2)

You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

60.4211(f)(2)(i)

Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator 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 calendar year.

BYUI will operate these two CI ICE for less than 100 hours per year for maintenance and testing.

60.4211(f)(2)(ii)

Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

BYUI will not operate these two CI ICE for emergency demand response purposes.

60.4211(f)(2)(iii)

Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

60.4211(f)(3)

Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

BYUI will not operate these two CI ICE for non-emergency situations more than 50 hours per year.

60.4211(f)(3)(i)

The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

60.4211(f)(3)(i)(A)

The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

60.4211(f)(3)(i)(B)

The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

60.4211(f)(3)(i)(C)

The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

60.4211(f)(3)(i)(D)

The power is provided only to the facility itself or to support the local transmission and distribution system.

60.4211(f)(3)(i)(E)

The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

60.4211(f)(3)(ii)

[Reserved]

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60.4211(g)

If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

BYUI will install, configure, operate and maintain the engines according to the manufacturer's instructions, and will not change the emission-related setting in a way not permitted by the manufacturer.

60.4211(g)(1)

If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

60.4211(g)(2)

If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

60.4211(g)(3)

If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[Amended at 76 FR page 37970, June 28, 2011; 78 FR page 6695, Jan. 30, 2013]

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 (e) of this section.

60.4212(a)

The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

60.4212(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.

60.4212(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.

60.4212(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.

60.4212(e)

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Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

BYUI will utilize the procedures listed in § 60.4212.

[Amended at 76 FR page 37971, June 28, 2011]

§ 60.4213 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 greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

60.4213(a)

Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

60.4213(b)

You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

60.4213(c)

You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

60.4213(d)

To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

60.4213(d)(1)

You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i= concentration of NO_X or PM at the control device inlet,

C_o= concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

60.4213(d)(2)

You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\, O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj}= Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2-15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$= Measured O_2 concentration, dry basis, percent.

60.4213(d)(3)

If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

60.4213(d)(3)(i)

Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm ^{3} /J (dscf/10 ^{6} Btu).

F_c= Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm ^{3} /J (dscf/10 ^{6} Btu).

60.4213(d)(3)(ii)

Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2}= CO_2 correction factor, percent.

5.9 = 20.9 percent O_2-15 percent O_2, the defined O_2 correction value, percent.

60.4213(d)(3)(iii)

Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj}= Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$= Measured CO_2 concentration, dry basis, percent.

60.4213(e)

To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d= Measured NO_X concentration in ppm.

$1.912x10^{-3}$= Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

60.4213(f)

To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj}= Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[Amended at 76 FR page 37971, June 28, 2011]

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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?

60.4214(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.

60.4214(a)(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.

60.4214(a)(1)(i)

Name and address of the owner or operator;

60.4214(a)(1)(ii)

The address of the affected source;

60.4214(a)(1)(iii)

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

60.4214(a)(1)(iv)

Emission control equipment; and

60.4214(a)(1)(v)

Fuel used.

60.4214(a)(2)

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

60.4214(a)(2)(i)

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

60.4214(a)(2)(ii)

Maintenance conducted on the engine.

60.4214(a)(2)(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.

60.4214(a)(2)(iv)

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

60.4214(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.

The two emergency CI ICE will meet the standards applicable to non-emergency engines in the applicable model year, and keep records of the operation of the engine in emergency and non-emergency service with a non-settable hour meter.

60.4214(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.

60.4214(d)

If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

BYUI will operate these two CI ICE only for emergency purposes or for testing and maintenance.

60.4214(d)(1)

The report must contain the following information:

60.4214(d)(1)(i)

Company name and address where the engine is located.

60.4214(d)(1)(ii)

Date of the report and beginning and ending dates of the reporting period.

60.4214(d)(1)(iii)

Engine site rating and model year.

60.4214(d)(1)(iv)

Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

60.4214(d)(1)(v)

Hours operated for the purposes specified in § 60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

60.4214(d)(1)(vi)

Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

60.4214(d)(1)(vii)

Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

60.4214(d)(2)

The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

60.4214(d)(3)

The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

[Amended at 78 FR page 6696, Jan. 30, 2013]

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

60.4215(a)

Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in § § 60.4202 and 60.4205.

60.4215(b)

Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

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60.4215(c)

Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

60.4215(c)(1)

For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

60.4215(c)(1)(i)

17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

60.4215(c)(1)(ii)

$45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

60.4215(c)(1)(iii)

9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

60.4215(c)(2)

For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

60.4215(c)(2)(i)

14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

60.4215(c)(2)(ii)

$44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

60.4215(c)(2)(iii)

7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

60.4215(c)(3)

Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[Amended at 76 FR page 37971, June 28, 2011]

§ 60.4216 What requirements must I meet for engines used in Alaska?

60.4216(a)

Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

60.4216(b)

Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections § § 60.4201(f) and 60.4202(g) of this subpart.

60.4216(c)

Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in § 60.4202 and § 60.4205, and not those for non-emergency engines in § 60.4201 and § 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in § 60.4201 and § 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

60.4216(d)

The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

60.4216(e)

The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

60.4216(f)

The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[Amended at 76 FR page 37971, June 28, 2011]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

BYUI will operate these two CI ICE with ultra low sulfur diesel fuel.

[76 FR page 37972, June 28, 2011]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in § § 60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(2)(ii) or (iii) and § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

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Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

BYUI has read and understands these definitions and used them in providing this regulatory analysis.

Subpart means 40 CFR part 60, subpart IIII.

[Amended at 76 FR page 37972, June 28, 2011; 78 FR page 6696, Jan. 30, 2013]

Table 1 to Subpart IIII of Part 60 —Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in § § 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards] **Maximum engine power**	**Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)**				
	NMHC + NO_X	**HC**	**NO_X**	**CO**	**PM**
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8<=KW<19 (11<=HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19<=KW<37 (25<=HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37<=KW<56			9.2 (6.9)		

(50<=HP<75)				
56<=KW<75 (75<=HP<100)		9.2 (6.9)		
75<=KW<130 (100<=HP<175)		9.2 (6.9)		
130<=KW<225 (175<=HP<300)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225<=KW<450 (300<=HP<600)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450<=KW<=560 (600<=HP<=750)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60 —Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in § 60.4202(a)(1), you must comply with the following emission standards] **Engine power**	**Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)**			
	Model year(s)	**NO_X+ NMHC**	**CO**	**PM**
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8<=KW<19 (11<=HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19<=KW<37 (25<=HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

These emission standards apply to the two CI ICE being installed as part of the boiler replacement project.

Table 3 to Subpart IIII of Part 60 —Certification Requirements for Stationary Fire Pump Engines

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	**Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)** [1]
KW<75 (HP<100)	2011
75<=KW<130 (100<=HP<175)	2010
130<=KW<=560 (175<=HP<=750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[76 FR page 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60 —Emission Standards for Stationary Fire Pump Engines

[As stated in § § 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8<=KW<19 (11<=HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19<=KW<37 (25<=HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37<=KW<56 (50<=HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ [1]	4.7 (3.5)		0.40 (0.30)
56<=KW<75 (75<=HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ [1]	4.7 (3.5)		0.40 (0.30)
75<=KW<130 (100<=HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+ [2]	4.0 (3.0)		0.30 (0.22)
130<=KW<225 (175<=HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ [3]	4.0 (3.0)		0.20 (0.15)
225<=KW<450 (300<=HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ [3]	4.0 (3.0)		0.20 (0.15)
450<=KW<=560 (600<=HP<=750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60 —Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19<=KW<56 (25<=HP<75)	2013
56<=KW<130 (75<=HP<175)	2012
KW≥130 (HP≥175)	2011

These labeling and recordkeeping requirements apply these two CI ICE.

Table 6 to Subpart IIII of Part 60 —Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed [1]	Torque (percent) [2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] Engine speed: ± 2 percent of point.

[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ± 2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60 —Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in § 60.4213, you must comply with the following requirements for performance	Complying with the requirement to	You must	Using	According to the following requirements

tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:] **For each**				
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix	(c) Measurements to determine moisture content must be made at the same time as the

	combustion engine exhaust at the sampling port location; and,	A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	measurement for NO_X concentration.
	iv. Measure NO_X at the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
	ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
	iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
	iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
	iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.

	sampling port location; and		
	iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60 —Applicability of General Provisions to Subpart IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and	Yes	

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reporting requirements

Federal Environment and Safety Codified Regulations
TITLE 40—Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

SUBPART KKKK—Standards of Performance for Stationary Combustion Turbines

Source Notes

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

60.4305(a)

If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

60.4305(b)

Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

Brigham Young University – Idaho (BYUI)is proposing to construct a new 40 MMBtu/hr natural gas-fired combustion turbine with distillate oil backup fuel. BYUI is therefore affected by this subpart.

§ 60.4310 What types of operations are exempt from these standards of performance?

60.4310(a)

Emergency combustion turbines, as defined in § 60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in § 60.4320.

60.4310(b)

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Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in § 60.4320 on a case-by-case basis as determined by the Administrator.

60.4310(c)

Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

60.4310(d)

Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?

60.4320(a)

You must meet the emission limits for NO_X specified in Table 1 to this subpart.

BYUI will meet the NOx emission limits specified in Table 1 to this subpart.

60.4320(b)

If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§ 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

BYUI will meet the NOx emission limits specified in Table 1 to this subpart.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

60.4330(a)

If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

60.4330(a)(1)

You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

60.4330(a)(2)

You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

BYUI will fire the combustion turbine only on natural gas with ultra low sulfur diesel as a backup fuel.

60.4330(a)(3)

For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

60.4330(b)

If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

60.4330(b)(1)

You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

60.4330(b)(2)

You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009, eff. May 19, 2009]

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

60.4333(a)

You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

BYUI will operate and maintain the combustion turbine and monitoring equipment in a manner consistent with good air pollution control practices to minimize emissions during startup, shutdown, and malfunction.

60.4333(b)

When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

60.4333(b)(1)

Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

60.4333(b)(2)

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

60.4335(a)

If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

The combustion turbine wil not utilize water or steam injection.

60.4335(b)

Alternatively, you may use continuous emission monitoring, as follows:

60.4335(b)(1)

Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

60.4335(b)(2)

For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

60.4335(b)(3)

For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

60.4335(b)(4)

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For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

60.4340(a)

If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with § 60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

BYUI will either perform annual or biannual performance tests in accordance with § 60.4400 as applicable, or will install continuous monitoring equipment as described in § 60.4335(b) and 60.4345.

60.4340(b)

As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

60.4340(b)(1)

Continuous emission monitoring as described in § § 60.4335(b) and 60.4345, or

60.4340(b)(2)

Continuous parameter monitoring as follows:

60.4340(b)(2)(i)

For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

60.4340(b)(2)(ii)

For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

60.4340(b)(2)(iii)

For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

60.4340(b)(2)(iv)

For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in § 75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_XCEMS is chosen:

60.4345(a)

Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

60.4345(b)

As specified in § 60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

60.4345(c)

Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

60.4345(d)

Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

60.4345(e)

The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

If continuous monitoring is chosen, the requirements of this section will followed as applicable.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to

identify excess emissions?

For purposes of identifying excess emissions:

If continuous monitoring is chosen, the requirements of this section will followed as applicable.

60.4350(a)

All CEMS data must be reduced to hourly averages as specified in § 60.13(h).

60.4350(b)

For each unit operating hour in which a valid hourly average, as described in § 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2(or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2(as applicable) may be used in the emission calculations.

60.4350(c)

Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

60.4350(d)

If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under § 60.7(c).

60.4350(e)

All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

60.4350(f)

Calculate the hourly average NO_X emission rates, in units of the emission standards under § 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

60.4350(f)(1)

For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad (Eq.\ 1)$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$= hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$= hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

60.4350(f)(2)

For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq.\ 2)$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$= electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$= electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (Eq.\ 3)$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 10_6= conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

60.4350(f)(3)

For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \qquad (Eq.\ 4)$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$= NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

60.4350(g)

For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in § 60.4380(b)(1).

60.4350(h)

For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in § 60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

60.4355(a)

The steam or water to fuel ratio or other parameters that are continuously monitored as described in § § 60.4335 and 60.4340 must be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

60.4355(a)(1)

Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

60.4355(a)(2)

Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

60.4355(a)(3)

Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

60.4355(a)(4)

Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

60.4355(a)(5)

Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

60.4355(a)(6)

Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

60.4355(a)(6)(i)

All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

60.4355(a)(6)(ii)

Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

60.4355(b)

For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in § 75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

The requirements of this section will followed as applicable.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used.

BYUI will monitor the total sulfur content of the fuel or use the ASTM or Gas Processors Association Standard as applicable.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

BYUI will utilize ultra low sulfur diesel fuel which will not exceed 0.060 SO_2/MMBtu heat input and is exempted from monitoring total sulfur content of fuel according to 60.4365(a).

60.4365(a)

The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

60.4365(b)

Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

60.4370(a) Fuel oil.

For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

BYUI will use one of the methods listed in 60.4370(a) to determine sulfur content of fuel oil.

60.4370(b) Gaseous fuel.

If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

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BYUI will demonstrate sulfur content using one of the options in § 60.4365.

60.4370(c) Custom schedules.

Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.4330.

If a custom schedule is used to determine total sulfur content of gaseous fuels it will substantiated and approved by the Administrator before use.

60.4370(c)(1)

The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

60.4370(c)(1)(i)

The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

60.4370(c)(1)(ii)

If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

60.4370(c)(1)(iii)

If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

60.4370(c)(1)(iii)(A)

Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

60.4370(c)(1)(iii)(B)

Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

60.4370(c)(1)(iii)(C)

Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

60.4370(c)(1)(iv)

If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

60.4370(c)(2)

The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

60.4370(c)(2)(i)

If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

60.4370(c)(2)(ii)

If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

60.4370(c)(2)(iii)

If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

60.4370(c)(2)(iv)

If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

60.4375(a)

For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

60.4375(b)

For each affected unit that performs annual performance tests in accordance with § 60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

BYUI will either use a continuous emissions monitor and report excess emissions and monitor downtime in accordance with 60.7(c), or perform annual performance tests in accordance with 60.4340(a).

§ 60.4380 How are excess emissions and monitor downtime defined for NO_X?

For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

60.4380(a)

For turbines using water or steam to fuel ratio monitoring:

60.4380(a)(1)

An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

60.4380(a)(2)

A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

60.4380(a)(3)

Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

60.4380(b)

For turbines using continuous emission monitoring, as described in § § 60.4335(b) and 60.4345:

60.4380(b)(1)

An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

60.4380(b)(2)

A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO 2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

60.4380(b)(3)

For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

60.4380(c)

For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

60.4380(c)(1)

An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

60.4380(c)(2)

A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

If continuous emission monitoring is chosen the requirements of 60.4380(b) will be followed.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

60.4385(a)

For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

60.4385(b)

If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

60.4385(c)

A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

BYUI has read and understands the requirements in 60.4385.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

The combustion turbine will not operate as an emergency combustion turbine or research and development turbine.

60.4390(a)

If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

60.4390(b)

Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under § 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

BYUI will comply with the the reporting requirement in 60.4395.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?

BYUI will conduct the initial and subsequesnt NOx performance tests according to one of the methods in § 60.4400

60.4400(a)

You must conduct an initial performance test, as required in § 60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

60.4400(a)(1)

There are two general methodologies that you may use to conduct the performance tests. For each test run:

60.4400(a)(1)(i)

Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7}= conversion constant, in lb/dscf-ppm

$(NO_X)_c$= average NO_X concentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

60.4400(a)(1)(ii)

Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_X emission rate in lb/MWh.

60.4400(a)(2)

Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

60.4400(a)(3)

Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

60.4400(a)(3)(i)

You may perform a stratification test for NO_X and diluent pursuant to

60.4400(a)(3)(i)(A)

[Reserved], or

60.4400(a)(3)(i)(B)

The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

60.4400(a)(3)(ii)

Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

60.4400(a)(3)(ii)(A)

If each of the individual traverse point NO_X concentrations is within ± 10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ± 5ppm or ± 0.5 percent CO_2(or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

60.4400(a)(3)(ii)(B)

For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ± 5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ± 3ppm or ± 0.3 percent CO_2(or O_2) from the mean for all traverse points; or

60.4400(a)(3)(ii)(C)

For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ± 2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ± 1ppm or ± 0.15 percent CO_2(or O_2) from the mean for all traverse points.

60.4400(b)

The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

60.4400(b)(1)

If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

60.4400(b)(2)

For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

60.4400(b)(3)

If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320 NO_X emission limit.

60.4400(b)(4)

Compliance with the applicable emission limit in § 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in § 60.4320.

60.4400(b)(5)

If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405) as part of the initial performance test of the affected unit.

60.4400(b)(6)

The ambient temperature must be greater than 0 ° F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under § 60.4345, then the initial performance test required under § 60.8 may be performed in the following alternative manner:

If BYUI installs a NOx-diluent CEMS the requirements of § 60.4405 will be followed.

60.4405(a)

Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 ° F during the RATA runs.

60.4405(b)

For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

60.4405(c)

Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4335.

60.4405(d)

Compliance with the applicable emission limit in § 60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with § 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.4355.

If continuous monitoring is chosen, monitor parameters will be established using the requirements in § 60.4410.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

60.4415(a)

You must conduct an initial performance test, as required in § 60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

The initial performance test will conducted using one of the methodologies in § 60.4415.

60.4415(a)(1)

If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see § 60.17) for natural gas or ASTM D4177 (incorporated by reference, see § 60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

60.4415(a)(1)(i)

For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see § 60.17); or

60.4415(a)(1)(ii)

For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17).

60.4415(a)(2)

Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see § 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad \text{(Eq. 6)}$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7}= conversion constant, in lb/dscf-ppm

$(SO_2)_c$= average SO_2 concentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

60.4415(a)(3)

Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see § 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

60.4415(b)

[Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in § 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

BYUI has read and understands these definitions.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11862, Mar. 20, 2009, eff. May 19, 2009]

Table 1 to Subpart KKKK of Part 60 —Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	<= 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	<= 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and <= 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	<= 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	<= 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and <= 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	<= 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and <= 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and <= 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 ° F	<= 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 ° F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

TAB 19

BYU IDAHO | Facilities Planning & Construction
283 University Operations Building · Rexburg, ID · 83460-8205 · Phone: (208) 496-2651

Pre-Permit Construction Approval Application

November 20, 2013

Idaho Department of Environmental Quality
Attn: Bill Rogers
1410 North Hilton
Boise, ID 83706-1255

RE: BRIGHAM YOUNG UNIVERSITY – IDAHO
PRE-PERMIT CONSTRUCTION APPROVAL APPLICATION

Dear Bill:

Brigham Young University – Idaho (BYUI) requests approval to begin construction prior to final approval of the permit to construct (PTC) to replace the existing coal boilers at the BYUI Heat Plant with natural gas-fired boilers and a combustion turbine/heat recovery steam generator. BYUI is eligible for pre-permit construction because it is not a major source under Prevention of Significant Deterioration regulations because:

- No netting of emissions to stay below major source levels is being relied upon,
- No use of offsets pursuant to IDAPA 58.01.01.206 is being used,
- No adverse impact on air quality related values of any Class 1 area will occur.

Documentation of this eligibility in contained in the PTC application attached to this letter. BYUI understands that approval to begin construction prior to PTC approval is subject to the following restriction:

- At our own risk,
- All emission limitations addressed in the application are enforceable,
- Emission units subject to the PTC may not be operated until the PTC is approved.

The PTC application for this project is attached, and it is the belief of BYUI that the application is complete. In addition, all public information notices have been published and all public informational meetings required by IDAPA 58.01.01.213 are being held within the required time periods in this regulation. Dispersion modeling has been performed according a modeling protocol submitted to and approved by IDEQ, and a report documenting the methods used and the results of the modeling are also being submitted with this request to begin construction prior to approval of the PTC.

If you have any questions or comments about this application, please do not hesitate to call me at (208) 496-2520, Al Oestmann (563) 260-0838, or Larry Veigel at (801) 322-0487.

Sincerely,

BRIGHAM YOUNG UNIVERSITY – IDAHO

Kyle Williams

Kyle Williams
Facility Manager Maintenance & Operations

cc: Mr. Larry Veigel, Heath Engineering Company (Salt Lake City, UT)
Mr. Al Oestmann, Trinity Consultants (West Burlington, IA)

TAB 20

SUBMIT THE PRE-CONSTRUCTION APPROVAL APPLICATION

The Pre-Permit Construction Approval Application was submitted for review on November 25, 2013:

Department of Environmental Quality
Air Quality Division
Stationary Source Program
Attn: Bill Rogers
1410 North Hilton
Boise, ID 83706-1255