PERMIT BOILERPLATE FOR SMALL BOILERS FIRING RESIDUAL OIL

I. PURPOSE

To specify requirements for permit approval for residual oil-fired boilers having a heat input capacity from 10 through 100 x 10^6 Btu/hr that may or may not also burn gaseous fuels. Boilers burning both residual and distillate oil may use this boilerplate in combination with the permit boilerplate for small gas and distillate oil-fired units provided that all the requirements in this boilerplate are met. This boilerplate may not apply to boilers subject to Prevention of Significant Deterioration (PSD) or Nonattainment permit review. Additional details concerning applicability are given in Section VI.A.

The boilerplate is meant to provide a guideline for the minimum requirements of the Department of Environmental Quality. More stringent requirements may be imposed if necessary to demonstrate compliance with NAAQS or other special requirements.

II. REFERENCES

Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution; Part V, Rules 5-1 (9 VAC 5-50-60 et seq.) through 5-5 (9 VAC 5-50-400 et seq.); Part VIII, 9 VAC 5-80-10; 40 CFR 60.40c through 60.48c (NSPS, Subpart Dc), American Society for Testing and Materials (ASTM) Standards D396, "Standard Specification for Fuel Oils" and D1835, "Standard Specification for Liquefied Petroleum Gasses".

III. DEFINITIONS

The following definitions are for use in this guideline and do not necessarily have the same meaning in other portions of the regulations.

boiler - a steam generating unit that combusts fuel by external combustion to produce steam or to heat any medium.

construction - fabrication or assembly of a new emissions unit. In the NSPS Regulations, the definition of construction includes "installation".

CEMS - continuous emissions monitoring system

COMS - continuous opacity monitoring system

installation - connecting and making an emissions unit that has previously been assembled at another location ready for use at the location of its intended use.

liquid petroleum gas - petroleum gas, including butane and propane, as defined by the American Society for Testing and Materials in ASTM D1835.
modification - see definition of "modification" under 9 VAC 5-80-10 B.3. of State Regulations.

natural gas - (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 D1835-86, "Standard Specification for Liquefied Petroleum Gases". This definition does <u>not</u> include synthetic gases.

process heater - 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.

reconstruction - the replacement of an emissions unit or its components to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital costs required to construct a comparable entirely new unit.

relocation - installation of an emissions unit that has been in service at another off-site location

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 D396-78, "Standard Specification for Fuel Oils". This definition does <u>not</u> include used or waste oil. Although diesel oil has its own ASTM specification, numbers 4, 5, and 6 diesel oil also meet the specifications for numbers 4, 5, and 6 fuel oil and should be considered as such.

steam generating unit - a device that combusts any fuel and produces steam or heats water or any other 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.

IV. <u>FUEL QUALITY SPECIFICATIONS</u>

A. Heat Content

Unless otherwise documented by the applicant, the following average heat content values for fuels may be used to calculate conservative estimates of emissions:

natural gas:	1,000 Btu/ft^3
liquid petroleum gas (butane):	97,000 Btu/gal
liquid petroleum gas (propane):	90,000 Btu/gal
#4 residual oil (including: #4 diesel oil)	144,000 Btu/gal
#5 residual oil (including: #5 diesel oil)	146,000 Btu/gal
#6 residual oil (including: #6 diesel oil)	150,000 Btu/gal

B. Density

Unless documented by the applicant, the following fuel densities may be used to calculate conservative estimates of emissions:

natural gas:	0.042 lb/ft^3
liquid petroleum gas (butane):	4.84 lb/gal
liquid petroleum gas (propane):	4.24 lb/gal
#4 residual oil (including: #4 diesel oil)	7.78 lb/gal
#5 residual oil (including: #5 diesel oil)	7.83 lb/gal
#6 residual oil (including: #6 diesel oil)	7.88 lb/gal

C. Fuel Sulfur Content

Unless specified and documented by specific analyses, the following sulfur content values may be used to calculate conservative estimates of emissions:

liquid petroleum gas (butane):	0.014 %* 15 gr/100 ft^3**
liquid petroleum gas (propane):	0.0185 %* 15 gr/100 ft^3**
#4, #5, and #6 residual oil: (including #4, #5, and #6 diesel oil)	must be certified by applicant not to exceed 0.5%, or be accompanied by emissions controls

* Maximum based on ASTM standards

** For LP gases, the S in the SO_2 emission factor equals the sulfur content expressed in gr/100 ft^3 gas vapor.

V. EMISSIONS CALCULATIONS

Unless specified and well documented by the applicant, the most recent AP-42 emission factors shall be used to calculate uncontrolled emissions. The most current AP-42 emission factors for industrial boilers (1998) are listed in the spreadsheet at K:\agency\dte\permast\dorong.wk4.

VI. REQUIREMENTS

A. Permitting Applicability

This boilerplate applies to construction, reconstruction, installation, modification, or relocation of boilers fired by residual oil having a heat input capability from 10 x 10^6 Btu/hr through 100 x 10^6 Btu/hr that may or may not also burn gaseous fuels. This boilerplate may be used as a guide for, but does not directly apply to boilers subject to the PSD or nonattainment permitting regulations. Also, this procedure could be used to permit boilers below 10 x 10^6 Btu/hr to avoid

PSD/nonattainment review.

B. NSPS Subpart Dc Applicability

NSPS Subpart Dc applies to construction, reconstruction, installation, or relocation of boilers fired by residual oil having a heat input capability from 10 x 10^6 Btu/hr through 100 x 10^6 Btu/hr.

Emissions requirements in this boilerplate are at least as stringent as NSPS Subpart Dc.

C. Permit Limits

1. While current procedure is to establish permit limits for emissions greater than or equal to 0.5 tons/yr, this procedure is under review and is subject to change. However, permit limits are necessary for each criteria pollutant when:

   a. There is an underlying standard. For example, in the Emission Standards for Fuel Burning Equipment, Rule 4-8, there are emission standards for particulate matter and SO_2. Therefore, permit limits should be established for particulate matter and SO_2.

   b. The limit is part of a BACT determination. For example, if low NO_x burners are required as part of a BACT determination then a permit limit for NO_x may be required.

   c. There is an air quality issue. For example, if modeling has indicated a limit is needed to meet a NAAQS then a permit limit may be necessary for that pollutant.

2. For units capable of burning both gas and residual oil, lb/hr limits are based on the higher emission rate of the fuels combusted. Separate emission rates are not necessary for each fuel. TSP, PM-10, SO_2, NO_x, and CO emission rates are generally higher when burning residual oil. VOC emissions are generally higher for gaseous fuels. However, it is recommended that the Environmental Engineer perform emissions calculations to confirm this assumption.

   Annual emissions limits in tons/yr are based on the permitted combination of fuel that produces the highest emission rate. An example is given in Attachment A.

3. An emission limit in lbs/10^6 Btu (0.50 lbs/10^6 Btu) **or lb/hr can be** used for SO_2. **Only one short term limit should be used. The lbs/10^6 Btu limit should be used when the sulfur content of the fuel is greater than 0.5%. When a lbs/10^6 limit is used, it should be calculated daily as a 30 day rolling limit.** Emission limits in lbs/10^6 Btu are not necessary for any other pollutants.

D. Sulfur Dioxide

1. Sulfur dioxide limits for natural gas and liquid petroleum gas are calculated based on the emission factors listed in the dorong.wk4 spreadsheet.

2. Residual oil-fired units must either burn oil with a sulfur content not to exceed 0.5 percent by weight or meet an SO_2 emissions limit of 0.50 lbs/10^6 Btu.

E. Other Criteria Pollutants

Emissions standards for other criteria pollutants are calculated based on the emission factors listed in the dorong.wk4 spreadsheet.

F. Opacity
Visible emissions shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity. This condition applies at all times except during startup, shutdown, or malfunction. This is more stringent than NSPS subpart Dc.

G. Toxic Pollutants

A non-criteria pollutant review may be necessary for residual oil-fired boilers in accordance with approved agency policies and procedures. Toxic pollutants that are not exempt for distillate and residual oil-fired units (up to 100 x 10^6 Btu/hr) are included in the dorong.wk4 spreadsheet. Exempt HAPs are listed in the notes at the bottom of the spreadsheet outside the selected print range. It may also be necessary to perform a toxic pollutant review on a facility-wide basis. Toxic pollutant evaluation and permit requirements should follow the current toxics procedure.

H. Fuel Sulfur Content

1. Liquid petroleum gas is required by ASTM standards to have a maximum sulfur content as stated in Section IV.C.

2. All uncontrolled residual oil-fired boilers must either burn oil not to exceed 0.5 percent sulfur, by weight, on an instantaneous basis, or meet an SO_2 emissions limit of 0.50 lbs/10^6 Btu on a 30-day rolling average.

3. The sulfur content of residual-oil fired units with emissions controls may vary, provided that SO_2 emissions do not exceed 0.50 lbs/10^6 Btu on a 30-day rolling average.

I. Fuel Sampling

1. No fuel sampling is necessary for gaseous fuels.

2. No fuel sampling is necessary for residual oil-fired boilers having a heat input capability of less than 30 x 10^6 Btu/hr. For these units, the permittee must obtain a "fuel supplier certification" that includes the following:

   a. the name of the oil supplier;

   b. 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;

   c. the sulfur content of the oil; and

   d. the method used to determine sulfur content.

3. For residual oil-fired boilers without SO_2 emissions controls having a heat input capacity greater than 30 x 10^6 Btu/hr, the permittee is required to either sample the sulfur content of the oil or demonstrate compliance by continuous emissions monitoring. If sampling is preferred, oil samples shall be taken <u>either</u>:

   a. once per day, in an as-fired condition, at the inlet to the boiler. The oil samples must be analyzed for sulfur content and heat content according to Method 19 (see 40 CFR 60, Appendix A, Method 19, paragraphs 5.2.2.1-3), <u>or</u>

   b. at the oil tank(s) immediately after each shipment of oil is added to the tank(s) and before any oil is combusted.

4. No fuel sampling is necessary for residual oil-fired units with emissions controls. Compliance with SO_2 emissions standards is to be determined by continuous emissions monitoring.

J. Emissions Monitoring (CEMS & COMS)

1. Emissions and opacity monitoring is not necessary for gas-fired units.

2. Residual oil-fired units <u>not</u> having SO_2 emissions controls and having a heat input capability of less than 30 x 10^6 Btu/hr are exempt from emissions and opacity monitoring requirements.

3. Residual oil-fired units <u>not</u> having SO_2 emissions controls and having a heat input capability of 30 x 10^6 Btu/hr or greater shall monitor for opacity. These units have the option of fuel sampling or continuous emissions monitoring to demonstrate compliance with SO_2 emissions limits.

4. Residual oil-fired units having SO_2 emissions controls shall monitor for SO_2, O_2, or CO_2 and opacity. Both SO_2 and opacity monitors shall be installed at the outlet of the applicable emissions control device. The SO_2

emissions monitor shall be used to determine compliance with the SO_2 emissions requirements. The quality assurance and data capture requirements of the NSPS apply (40 CFR 60, Appendix B).

5. Multiple units exhausting through a common stack may use a single opacity monitor, but not a single SO_2 monitor. If a new unit is being added to a common stack with existing units, the entire stack must meet the lowest opacity limit of the units being vented into that stack while the new unit is on line. A single SO_2 monitor is required for each applicable facility.

K. Emissions Testing

1. A three-hour opacity test is required for all residual oil-fired units. This is more stringent than NSPS Subpart Dc which only requires a performance test for units 30 million Btu/hr or greater. The test is usually to be performed by an independent testing consultant within 60 days after achieving maximum operation but no later than 180 days after initial startup. Testing must be done while the unit is firing residual oil. Test results are to be submitted within 45 days after test completion to the regional office and EPA Region III when the unit is 30 million Btu/hr or greater.
2. An opacity test is optional for gas-fired units at the discretion of the regional office.

3. Particulate emissions testing is not required for gas and residual oil-fired units.

4. Sulfur dioxide emissions testing is not necessary for gas- and residual oil-fired units without emissions controls. Sulfur dioxide testing is required for residual oil-fired units with emissions controls.

5. All emissions testing should be conducted at 90 percent of rated capacity or greater. Opacity tests may be performed at various loads.

L. Training, Operation, and Maintenance

All boiler operators must receive training in the operation of the boiler and, if applicable, emissions controls. Training shall consist of review and familiarization of the manufacturer's operating instructions, at minimum. In addition, the permittee must maintain on site operation and maintenance procedures. These procedures shall be based on the manufacturer's recommendations, at minimum.

M. Notification

1. The owner or operator of all facilities subject to this boilerplate must submit notification of the following:

   a. the date of commencement of construction or reconstruction;

b. the anticipated date of start-up;

c. the actual date of start-up;

d. the anticipated date of emissions tests, including opacity; and

e. the anticipated date of the continuous emissions monitor performance evaluation, if applicable.

Each notification shall be submitted to the Regional Office with copies mailed to the NSPS Coordinator, EPA Region III.

Note: NSPS Subpart Dc requires that notification of the actual start-up date for residual oil-fired boilers include the design heat input capacity of the unit, the type of fuel to be combusted, and the expected annual capacity factor for each individual fuel fired. However, this information is included in the permit which is sent to EPA Region III, and it is agency procedure that such notification is redundant. Thus, additional notification is not required.

2. The owner or operator of all facilities must notify the Department of any malfunction causing excess emissions for more than one hour. This notification shall be made by facsimile transmission, telephone, or telegraph within four business hours of the occurrence. Written notification shall be required within 14 days which includes all pertinent facts, including the estimated duration of the breakdown.

N. Record Keeping

1. All facilities operating residual oil-fired units must maintain the following records on site:

a. a statement of the time place, and nature of training provided to each boiler operator,

b. a boiler operating and maintenance procedure, and,

c. a daily record of residual oil and natural gas consumed (kept current for the most recent two years). On a case by case basis, EPA may approve less frequent reporting of fuel consumption for natural gas. The permittee should make the request to EPA, Region III.

2. Residual oil-fired units <u>not</u> having SO_2 emissions controls and having a heat input capability of less than 30 x 10^6 Btu/hr are required to keep all fuel supplier certifications on site for two years.

3. Residual oil-fired units not having SO_2 emissions controls and having a heat input capability of 30 x 10^6 Btu/hr or greater are required to keep fuel sampling records and opacity monitoring data on-site for the most current two years.

4. Residual oil-fired units having SO_2 emissions controls are required to keep SO_2 monitoring data on site for the most current two years.

O. Reporting

1. One copy of emissions testing data and the CEMS performance evaluation reports shall be submitted to the Regional Office with copies mailed to the Chief - Air Enforcement Branch, EPA Region III.

2. All facilities having visible emissions monitors shall submit quarterly excess opacity reports conforming to the Opacity Monitoring Report Format of the permit boilerplate.

3. All facilities operating residual oil-fired units shall submit quarterly SO_2 emissions reports to the Regional Office with copies mailed to the Chief - Air Enforcement Branch, EPA Region III. For applicants that demonstrate compliance with SO_2 emissions limits by fuel sampling, the report shall include the following:

   a. the dates included in the reporting period,

   b. records of the amount of each fuel burned during the calendar quarter,

   c. copies of all fuel supplier certifications (when applicable), or copies of all oil analyses taken from the storage tank after each shipment is received (when applicable),

   d. a signed statement from the owner or operator that the fuel supplier certifications represent all of the fuel burned during the calendar quarter (when applicable).

   If no shipments of residual oil were received during the calendar quarter, the quarterly report shall include item 4a. as listed below and a statement that no oil was received during the calendar quarter.

4. For applicants that demonstrate compliance with the SO_2 emission standard by continuous emissions monitoring, the report shall include the following:

   a. the dates included in the reporting period;

   b. each 30-day average SO_2 emissions rate (in lbs/10^6 Btu) calculated daily for the periods during which the boiler burned residual oil, reasons for each noncompliance with emissions standards and a description of corrective actions taken;

c. identification of any steam generating unit operating days for which SO_2, O_2, or CO_2 data have not been obtained by an approved method for at least 75 percent of operating hours, reasons for not obtaining sufficient data and corrective actions taken;

d. 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 action taken if data have been excluded for periods other than when oil was not combusted in the unit;

e. identification of the F factor used in calculations, method of determination for each type of fuel combusted, and type of fuel combusted;

f. if a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS;

g. if a CEMS is used, description of any modifications to the CEMS that could effect the ability of the CEMS to comply with Performance Specifications 2 or 3, Appendix B, 40 CFR 60; and

h. if a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1, 40 CFR 60.

5. If the unit does not have emissions controls and the applicant chooses to demonstrate compliance by continuous emissions monitoring, the quarterly report shall also include each 3-hr average when SO_2 is in excess of 0.50 $lbs/10^6$ Btu.

P. Modeling

Modeling should follow current agency guidelines.

Q. Permit Approval

In accordance with the current Delegations of Authority Memorandum, approval authority has been delegated to the Regional Office. The Regional Permit Manager may sign for the Executive Director.

ATTACHMENT A
CALCULATION OF PERMIT LIMITS FOR MULTIPLE FUELS

Example:

An applicant proposes to install a 15.0 x 10^6 Btu/hr boiler firing # 6 residual oil with 0.5 % sulfur and natural gas. The applicant request the following fuel use rates:

Maximum #6 oil consumption:	100 gallons/hr
	500,000 gallons/yr
Equivalent operation on oil:	5000 hours/year
Maximum gas consumption:	15,000 ft^3/hr
	75 x 10^6 ft^3/yr
Equivalent operation on gas:	5000 hours/yr

CRITERIA POLLUTANTS

Based on the assumed emission factors and fuel characteristics in Sections IV and V and the NSPS standard for SO_2, short term emissions are calculated as follows:

TSP

#6 residual oil:

0.1 x 10^3 gal/hr x (9.19 x 0.5%S + 3.22) lbs/10^6 gals = 0.78 lbs/hr

natural gas:

0.015 x 10^6 ft^3/hr x 7.6 lbs/$10^6$$ft^3$ x = 0.11 lbs/hr

worst case fuel: residual oil

PM-10

#6 residual oil

0.1 x 10^3 gal/hr x (8.03 x 0.5%S + 2.65) lbs/10^6 gals = 0.68 lbs/hr

natural gas:

0.015 x 10^6 ft^3/hr x 7.6 lbs/$10^6$$ft^3$ x = 0.11 lbs/hr

worst case fuel: residual oil

SO_2

#6 residual oil

0.1 x 10^3 gal/hr x 158.6 x (0.5%S) lbs/10^3 gals = 7.93 lbs/hr,

natural gas:

0.015 x 10^6 ft^3/hr x 0.6 lbs/$10^6$$ft^3$ = 0.01 lbs/hr

worst case fuel: residual oil

NO_x

#6 residual oil:

0.1 x 10^3 gal/hr x 55.0 lbs/10^3 gals = 5.50 lbs/hr

natural gas:

0.015 x 10^6 ft^3/hr x 100.0 lbs/10^6 ft^3 = 1.50 lbs/hr

worst case fuel: residual oil

CO
#6 residual oil:
0.1×10^3 gal/hr x 5.0 lbs/10^3 gals = 0.50 lbs/hr
natural gas:
0.015×10^6 ft3/hr x 84.0 lbs/10^6 ft^3 = 1.26 lbs/hr
worst case fuel: natural gas

VOC
#6 residual oil:
0.1×10^3 gal/hr x 0.28 lbs/10^3 gals = 0.03 lbs/hr
natural gas:
0.015×10^6 ft^3/hr x 5.5 lbs/10^6 ft^3 = 0.08 lbs/hr
worst case fuel: natural gas

Lead
natural gas: assumed negligible
#6 residual oil:
0.1×10^3 gal/hr x 0.00151 lbs/10^3 gals = 0.000151 lbs/hr
worst case fuel: residual oil

Using the dorong.wk4 spreadsheet, all toxics are below the corresponding exemption level on an hourly basis.

Calculation of annual emissions may be a bit more difficult. Obviously, the applicant cannot burn residual oil for 5000 hours and natural gas for 5000 hours in the same year. He can, however, burn 5000 hours of gas or 5000 hours of residual oil in any one year. Therefore it is feasible to write a permit limit that allows the consumption of both 500,000 gallons of oil (5000 hours) and 75×10^6 ft^3 of gas (5000 hours) per year. By limiting the hourly rated capacity of the boiler, the Department has a means of ensuring that both 500,000 gallons oil and 75×10^6 ft^3 of gas are not burned in the same year.

Under these conditions, the annual emissions limit must be based on the worst case annual emissions. In this example, the worst-case TSP, PM-10, SO_2, NO_x, and lead emissions occur while the boiler is operating at full load for 5000 hours (500,000 gals/yr) on residual oil and the remainder of the year, 3760 hours (56.4×10^6 ft^3/yr), on natural gas. Worst case CO and VOC emissions occur when the boiler is operating at full load for 5000 hours (75×10^6 ft^3/yr) on natural gas and for 3760 hours (376,000 gals/yr) on residual oil.

In general, a natural gas/residual oil boiler emits more TSP, PM-10, NO_x, SO_2, and lead while burning oil and more VOC while burning gas. CO may be higher for either fuel. In any case, calculations should be done to determine the worst-case fuel.

Annual emissions are calculated as follows:

TSP

#6 residual oil:
500×10^3 gal/yr x [9.19 x(0.5%S)+ 3.22] lbs/10^3 gals / 2000 lbs/ton = 1.95 tons/yr
natural gas:
56.4×10^6 ft^3/yr x 7.6 lbs/$10^6 ft^3$ / 2000 lbs/ton = 0.21 tons/yr
total:
1.95 + 0.21 = 2.16 tons/yr

PM-10
#6 residual oil:
500×10^3 gal/yr x [8.03 x(0.5%S)+ 2.65] lbs/10^3 gals / 2000 lbs/ton = 1.70 tons/yr
natural gas:
56.4×10^6 ft^3/yr x 7.6 lbs/$10^6 ft^3$ / 2000 lbs/ton = 0.21 tons/yr
total:
1.70 + 0.21 = 1.91 tons/yr

SO_2
#6 residual oil:
500×10^3 gal/yr x 158.6 (0.5 %S) lbs/10^3gal / 2000 lbs/ton = 19.83 tons/yr
natural gas:
56.4×10^6 ft^3/yr x 0.6 lbs/$10^6 ft^3$ / 2000 lbs/ton = 0.02 tons/yr
total:
19.83 + 0.02 = 19.85

NO_x
#6 residual oil:
500×10^3 gal/yr x 55.0 lbs/10^3 gals / 2000 lbs/ton = 13.75 tons/yr
natural gas:
56.4×10^6 ft^3/yr x 100.0 lbs/10^6 ft^3 / 2000 lbs/ton = 2.82 tons/yr
total:
13.75 + 2.82 = 16.57 tons/yr

CO
natural gas:
75×10^6 ft^3/yr x 84.0 lbs/10^6 ft^3 / 2000 lbs/ton = 3.15 tons/yr
#6 residual oil:
376×10^3 gal/yr x 5.0 lbs/10^3 gals / 2000 lbs/ton = 0.94 tons/yr
total:
3.15 + 0.94 = 4.09 tons/yr

VOC
natural gas:
75×10^6 ft^3/yr x 5.5 lbs/10^6 ft^3 / 2000 lbs/ton = 0.21 tons/yr
#6 residual oil:
376×10^3 gal/hr x 0.28 lbs/10^3 gals / 2000 lbs/ton= 0.05 lbs/hr
total:
0.21 + 0.05 = 0.26 tons/yr

Lead
#6 residual oil:

0.000151 lb/hr x 5000 hr/yr / 2000 lbs/ton = 0.0004 tons/yr
natural gas: assumed negligible
total:
0.0004 + 0 = 0.0004

Using the spreadsheet for oil-fired boilers, all toxics are exempt on an annual basis.

Considering the Department's procedure of not writing permit limits for calculated criteria pollutant emissions of less than 0.5 tons/yr, the suggested permit limits are as follows.

Fuel Consumption Limits:
#6 residual oil: 500,000 gallons/yr
natural gas: 75 x 10^6 ft/year

Short term limits:

Pollutant	Limit	Comment
TSP	0.8 lbs/hr	based on residual oil
PM-10	0.7 lbs/hr	based on residual oil
SO_2	0.50 lb/10^6 Btu	based on residual oil, 0.5%sulfur
NO_x	5.5 lbs/hr	based on residual oil
CO	0.5 lbs/hr	based on natural gas
VOC	None	emissions < 0.5 tons/yr
Lead	None	emissions < 0.5 tons/yr
Toxics	per current agency procedure	

Annual limits:

Pollutant	Limit	Comment
TSP	2.2 tons/yr	5000 hours oil, 3760 hours gas
PM-10	1.9 tons/yr	5000 hours oil, 3760 hours gas
SO_2	19.9 tons/yr	5000 hours oil, 3760 hours gas
NO_x	16.6 tons/yr	5000 hours oil, 3760 hours gas
CO	4.1 tons/yr	5000 hours gas, 3760 hours oil
VOC	None	emissions < 0.5 tons/yr
Lead	None	emissions < 0.5 tons/yr
Toxics	per current agency procedure	

NON-CRITERIA POLLUTANTS

Limits are to be calculated and enforced according to approved agency procedures.

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