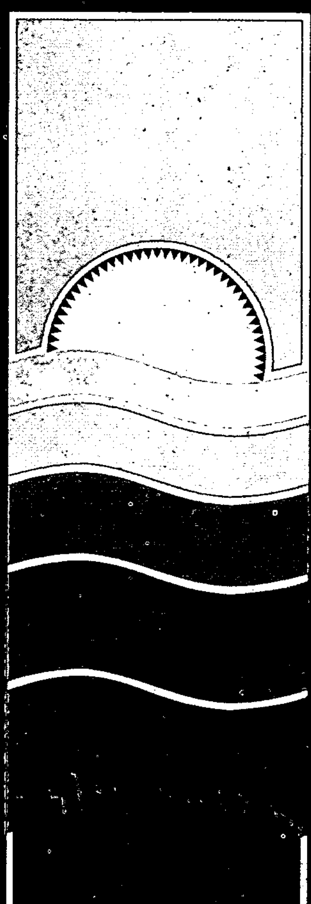

CCME

Canadian Council of Ministers of the Environment

Le Conseil canadien des ministres de l'environnement

NATIONAL EMISSION GUIDELINE

FOR

COMMERCIAL/INDUSTRIAL BOILERS AND HEATERS

Initiative N306
March 1998
PN 1286

The Canadian Council of Ministers of the Environment (CCME) is the major intergovernmental forum in Canada for discussion and joint action on environmental issues of major national, international and global concern. The 13 member governments work as partners in developing nationally consistent environmental standards, practices and legislation.

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Table of Contents

Glossary of Terms

Within the context of this guideline, the meaning of certain terms is as described below.

Actual Thermal Efficiency: The thermal efficiency of a boiler measured in accordance with section vii) b) of this Guideline.

Applied Emission Limit: The emission limit that a boiler or heater is expected to meet having taken into account, where applicable, measures to increase thermal efficiency.

Blast Furnace Stove (steel sector): A stove used to preheat ambient air for use in blast furnace ironmaking chemical reactions. The stove is a vertical cylindrical refractory filled regenerator. Multiple stoves are used at a single blast furnace to maintain a continuous flow of hot air. Stove technology is specific to the steel sector.

Boiler: Any combustion equipment fired with fossil fuel, biomass or a by-product derived from fossil fuel, for the purpose of generating hot water or steam. This definition excludes equipment that:

i) has a thermal input capacity in excess of 73 megajoules per second (megawatts thermal) (this is approximately equal to 250 million British thermal units per hour) and is used by an electric power utility for the generation of electricity;

or

ii) recovers sensible heat from the exhaust of combustion equipment that is designed primarily for purposes other than to generate hot water or steam.

By-product Fuel: A fuel derived from any primary process (or operation) but not intentionally produced for commercial purposes that contains constituents that carry a certain caloric value and that may or may not contain sensible or latent heat. Thermal oxidation (or combustion) of the by-product fuel is required to release the caloric content of the fuel in the form of heat.

By-product Fuel Boiler: A combustion appliance that burns by-product fuel(s) to produce steam or hot water.

Capacity: The maximum rate of energy input to a boiler or heater, as specified by the nameplate of the boiler or heater, or the sum of the energy input ratings of all the burners used for firing the boiler or heater, whichever is less. (Where a boiler has been derated, it is the responsibility of the owner to provide evidence to the provincial or regional environmental authority supporting any deviation from the boiler nameplate or burner ratings.)

Cat Cracker (refining sector): A petroleum refining process (catalytic cracker) unit designed to convert medium gravity hydrocarbon feedstocks into lighter hydrocarbons. High temperature and catalysts are used to "crack" the heavier hydrocarbons.

Chemical Recovery Boiler : (pulp and paper sector) A boiler in which the fuel fired includes spent pulping liquor and which functions to recover chemical components from the pulping liquor.

Coker (refining sector): A petroleum refining process unit designed to upgrade heavier hydrocarbons in crude oil into lighter hydrocarbons and petroleum coke by applying heat to break up the heavier hydrocarbons.

Coke-Fired Boiler (refining sector): A boiler whose primary fuel is the petroleum coke produced in a coker unit.

Coke Oven (steel sector): A coke oven is used to convert coal to coke through distillation. Multiple banks of ovens and heating chambers are alternated to form a coke battery. Finished coke is pushed through the oven and collected out the back side. Coke ovens are highly specialized within the steel sector.

Current Total Erected Costs: Costs of total replacement (purchased, constructed and installed), expressed in current dollars, of the boiler or heater, including burners, burner management and control systems but excluding the stack, flue gas ducting, feedwater system and fuel delivery system.

Distillate Oil: Any fuel oil that complies with the specifications of fuel oils #1, 2 or 3, as defined by the American Society for Testing and Materials (ASTM) burner fuel specification D396-78.

Glossary of Terms (continued)

Fossil Fuel:	Natural gas, petroleum, coal or any form of gaseous, liquid or solid fuel derived from such and used for creating useful heat.
Gaseous Fuel:	A fuel that, at atmospheric conditions, is a gas, and that is composed of natural gas, propane, carbon monoxide, coke oven gas, refinery fuel gas or any combination of these gases, except where the hydrogen content is greater than 10% by volume.
Heater:	Any combustion equipment fired with fossil fuel, or a by-product derived from fossil fuel, for the purpose of transferring heat directly or indirectly to material being processed, excluding equipment that comes under the definition of a "boiler." A "heater" does not include any kiln or oven used for drying, baking, cooking, calcining or vitrifying; or any process used to chemically transform ore or intermediate products into bulk metallic products.
Modified Boiler or Heater:	The precise definition of a modified boiler or heater is left to the implementing province. See discussion under "Application."
New Boiler or Heater:	Any boiler or heater that receives final provincial or regional regulatory environmental approval for construction on or after a date two years subsequent to the publication of this Guideline.
Nitrogen Oxides (NO_x):	The sum of nitric oxide (NO) and nitrogen dioxide (NO_2) expressed collectively as a nitrogen dioxide equivalent.
Primary Fuel:	Any fuel used as the main source of energy input to the boiler or heater for more than 500 hours per year.
Pyrolysis Heater (petrochemical sector):	Process type heater with a tubular reactor that serves a dual purpose: to absorb the heat from combustion; and to complete the desired cracking reaction in the furnace.
Reconstruction:	Regular maintenance and repairs; does not deal with upgrading/downsizing a unit.
Reference Emission Limit:	An emission limit, assigned in section ii) or iii) of this Guideline, judged to be achievable for new sources on a national basis through application of a reasonable level of emission control technology, exclusive of measures designed specifically to increase thermal efficiency.
Reference Thermal Efficiency:	A thermal efficiency, assigned in section iv) of this Guideline, judged to be readily achievable by a representative commercially available boiler.
Reheat Furnaces (steel sector):	A reheat furnace is used to "reheat" steel (slabs, billets, etc.) for rolling/processing into final shape. The reheat furnace is generally a large, long horizontally designed unit through which charged steel is moved continuously. Slab reheat furnaces are unique to the steel sector.
Residual Oil:	Any fuel oil that complies with the specifications of fuel oils #4, 5 or 6, as defined by the American Society for Testing and Materials (ASTM) burner fuel specification D396-78.
(Steam) Cracking Heater (refining sector):	A type of pyrolysis heater designed for thermal cracking (decomposition) of hydrocarbons.
Standby Fuel:	Any fuel used as the main source of energy input to the boiler or heater for less than or equal to 500 hours per year.
(Steam) Reformer Heater (refining sector):	A type of pyrolysis heater designed for a catalytic reforming process that produces hydrogen and carbon oxides from steam and hydrocarbons under the influence of heat in the presence of a catalyst.
Thermal Efficiency:	The thermal efficiency of a boiler or heater is a measure of the amount of energy extracted and utilized by the system in relation to the amount of energy in the fuel, measured at steady-state operation. This is normally measured by the indirect (heat/stack loss) method. Refer to section vii) b) of this document.
Wood/Biomass:	(to be determined)

Abbreviations

CCME	Canadian Council of Ministers of the Environment
CEM	Continuous emissions monitoring
CEPA	*Canadian Environmental Protection Act*
g/GJ_I	grams of substance emitted per gigajoule of energy input, on a higher heating value basis
GJ/hr	gigajoules per hour
kPa	kilopascals
MMBtu/hr	million British thermal units per hour
NO_x	nitrogen oxides, including nitric oxide and nitrogen dioxide, expressed collectively as a nitrogen dioxide equivalent
NO_2	nitrogen dioxide
O_2	oxygen
ppmv	parts per million by volume
VOCs	volatile organic compounds

Preface

In May 1991, the Canadian Council of Ministers of the Environment (CCME) issued Phase 1 of the Management Plan for Nitrogen Oxides (NO_X) and Volatile Organic Compounds (VOC). The aim of the Plan is consistent attainment of the Canadian maximum acceptable one-hour air quality objective for ozone of 82 parts per billion by the year 2005. This Guideline responds to initiative N306 of the Plan, one of a series of initiatives aimed at preventing future increases in emissions through emission limits for new sources. Initiative N306 calls for the development of a national emission guideline defining NO_X emission limits for new commercial/ industrial boilers and heaters, effective 1994. While this Guideline establishes maximum broad national emission limits, it is acknowledged that federal, provincial or regional environmental authorities may impose more stringent limits in response to regional or local problems.

Other initiatives under the NO_X/VOC Management Plan (Smog Plan) have identified that additional efforts will be required to meet the original ambient air quality objective for ozone and, further, that there is a need to set a more stringent ozone objective. A Phase 2 Federal Smog Plan was released in November 1997, and regional smog plans are also forthcoming in several provinces. These developments will have implications for the implementation of this guideline as well as treatment of existing sources.

This Guideline was developed by a multistakholder consultation process involving representatives from industry, manufacturers, environmental groups, and regional, provincial and federal governments. During the process, participants considered the development of NO_X emission limits for all boilers and heaters in all sectors of the economy. However, they concluded that national emission limits constitute a reasonable mechanism for pollution prevention for larger new and modified boilers and heaters of a capacity > 10.5 GJ/hr (10 MMBtu/hr), and developed the limits presented in this Guideline for these sources only. At the same time, they concluded that for other sources there exist more practical, effective and economical means of controlling emissions. These sources include:

i) existing boilers and heaters;
ii) the very large numbers of smaller new boilers and heaters (capacity < 10.5 GJ/hr [10 MMBtu/hr]);
iii) other stationary combustion sources not addressed under this or other national guidelines.

For these sources it is recommended that the following action be taken:

1. Existing Sources

To deal efficiently with controlling NO_X emissions from existing sources in areas where remedial action is required:

a) Larger existing facilities should undertake a program of emission reduction targets applied to the total annual emissions from all sources within a facility. Such a program would account for emission reduction options that could not be encompassed by a national guideline. These could include site-specific opportunities for energy conservation, process changes and emission reductions from sources other than boilers and heaters. This program would begin with a voluntary effort, after which NO_X emission reductions would be enforced only where necessary. A range of emission reduction program alternatives, including emission trading should be investigated.

b) For all large and small existing boilers and heaters, an inspection and maintenance program should be developed by boiler and heater manufacturers, industry associations, service companies and/or fuel supply utilities to optimize performance and minimize fuel consumption.

2. New Boilers and Heaters of less than 10.5 GJ/hr (10 MMBtu/hr) Capacity

Boilers and heaters with a heat input capacity of less than 10.5 GJ/hr (10 MMBtu/hr) account for an estimated 98% of the total number of units (estimated at 600 000), 50% of capacity and close to 40% of NO_x emissions from boilers and heaters in Canada. Pollution prevention measures for these boilers and heaters are therefore believed to be essential. Provincial resources are not adequate to deal with this number of sources through conventional regulatory and permitting processes. However, the Standards Council of Canada oversees a number of design standards for small boilers and heaters that are implemented efficiently and independently of the provincial environmental regulatory/permit process. It is therefore recommended that a design standard for minimizing the NO_x emissions of boilers and heaters of less than 10.5 GJ/hr (10 MMBtu/hr) capacity be developed under the auspices of the Standards Council of Canada. The first steps toward this were taken in October 1996 by federal and provincial governments and other stakeholders.

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Introduction

This National Emission Guideline for Commercial/ Industrial Boilers and Heaters was developed to provide a consistent national basis for reducing emissions of nitrogen oxides (NO_X), while encouraging greater energy efficiency in the operation of new and modified commercial/ industrial boilers and heaters. During the consultation process for the development of the Guideline, a Technical Background Document was developed to provide the following information:

- a description of the industrial utilization of boilers and heaters;
- an inventory of boilers and heaters in Canada;
- a review of NO_X emission reduction options;
- a review of options for emission verification measurements;
- comparative standards for NO_X emissions from other jurisdictions.

This document is available from Environment Canada.

All commonly available and applicable methods of NO_X emission reduction have been assessed as part of the development of the Guideline. These include combustion technologies that reduce or prevent emissions at their point of generation, and post-combustion controls that reduce emissions after generation. The methods considered included the following:

- combustion operation modifications, such as the use of low excess air and the reduction of combustion air temperature;
- low NO_X burners;
- flue gas recirculation;
- staged combustion;
- selective non-catalytic and catalytic reduction.

The Guideline recognizes that efficient combustion operation is an effective way to reduce emissions from most industrial boilers and heaters, and that it will also address emissions of other pollutants, including greenhouse gases. The reference emission limits set out in the Guideline are based on proven compatibility with efficient combustion operation and the use of cost-effective technology such as low NO_X burners. Only in isolated cases might it be necessary to employ a post-combustion control technology, such as selective non-catalytic or catalytic reduction, to meet the reference emission limits.

The Guideline incorporates a system of energy-efficiency credits that allow the reference emission limits to be adjusted upward in recognition of the reduction in overall net emissions achieved through increased thermal efficiency of the boiler or heater. Increasing other operating efficiencies beyond the boundary of the boiler or heater is also recognized as an effective way to reduce emissions. However, the scope of these opportunities was too broad to enable their inclusion in this Guideline.

The application of this Guideline to new sources is based on the rationale that the design and specification process is generally the point in the life cycle that offers the greatest flexibility in meeting emission targets. Pollution prevention measures applied at this point are the least costly and most efficient means of reducing emissions.

The application of this Guideline to modified sources is based on the rationale that major modifications present an opportunity to implement pollution prevention measures at relatively low cost, and to reduce the need for more costly remedial programs. Where the life span of existing sources can be extended indefinitely, the time of modification may represent the only real opportunity for emission reduction. If emission reduction measures were applied only to new equipment, investment decisions would be biased toward keeping older, more polluting equipment operating.

It was originally intended that this Guideline include emission limits for boilers and heaters burning all commonly used fuels. However, delays were encountered in developing provisions for wood and biomass-fired units. Work will continue on this and provisions for these units will be incorporated into the Guideline at a later date.

Emission Limits

i) Application

a) **Effective date:** The Guideline applies to a boiler or heater that receives final provincial or regional regulatory environmental approval for construction on or after a date two years subsequent to the publication of this Guideline (as per the glossary definition "New Boiler or Heater").

b) **Capacity**: The Guideline applies to all new and modified fossil fuel-fired boilers and heaters with a capacity equal to or greater than 10.5 GJ/hr (10 MMBtu/hr). The unit capacity to which wood/biomass limits apply is to be determined.

c) **Fuel:** The Guideline applies where a fossil fuel-fired boiler or heater is fired with a primary fuel and does not apply where a boiler or heater is fired with a standby fuel. Application according to fuel for wood/biomass units is to be determined.

d) **Modified boilers and heaters:** The application of this Guideline to modified sources will be determined by the implementing province. A suggested approach to defining a "modified source" for fossil fuel-fired boilers and heaters is as follows:

An existing source would be defined as "modified" when subject to one or both of two types of work that can be done on conventional boilers or heaters, namely:

i) **Type 1 Work** would relate to process or capacity change or improvement such that the work would constitute "modification" if it exceeded 12.5% of the current total erected costs and involved a burner change.

ii) **Type 2 Work** would relate to reconstruction such that the work would constitute "modification" if it exceeded 50% of the current total erected costs.

The application of this Guideline to modified boilers and heaters should account for and avoid the creation of obstacles to modifications where the primary intent and result is energy conservation.

The application of the Guideline to modified sources firing wood/biomass is to be determined.

ii) Reference Emission Limits for New Fossil Fuel-Fired Boilers and Heaters

a) **Nitrogen oxides (NO_X):** Emissions of NO_X as nitrogen dioxide, in units of g/GJ_i, from new boilers and heaters, according to primary fuel, should not exceed the following:

Capacity		NO_x Emission Limit (g/GJ_i)			
(GJ/hr)	(MMBtu/hr)	Gaseous Fuel	Distillate Oil	Residual Oil <0.35% Nitrogen	Residual Oil ≥ 0.35% Nitrogen
10.5 - 105	(10 - 100)	26	40	90	110
> 105	(> 100)	40	50	90	125

b) Carbon monoxide: The emission limit for carbon monoxide for all units is 125 g/GJi,

iii) Reference Emission Limits for Wood/ Biomass Fuel-Fired Boilers

Emission limits for wood/biomass-fired boilers are to be determined.

iv) Energy Efficiency Credits

Where it can be demonstrated by the proponent that a new boiler or heater is designed and operated to achieve enhanced energy efficiency, an emission allowance or credit should be considered. Such a credit would recognize the reduction in overall net emissions achieved through energy efficiency.

In cases where energy efficiency measures have been implemented, the limits for NO_X emissions (reference limits) should be adjusted by applying energy efficiency credits according to the formula:

$$\begin{array}{c}\text{Applied } NO_X\\ \text{Emission Limit}\end{array} = \begin{array}{c}\text{Reference } NO_X\\ \text{Emission Limit}\end{array} \times \begin{array}{c}\text{Energy Efficiency}\\ \text{Credit}\end{array}$$

Boilers

For boilers, the energy efficiency credit would be calculated using a reference thermal efficiency at "rated capacity," where:

$$\begin{array}{l}\text{Energy}\\ \text{Efficiency}\\ \text{Credit}\end{array} = \frac{\begin{array}{c}\text{Actual Thermal Efficiency of Boiler}\\ \text{(determined as described in vii b))}\end{array}}{\text{Reference Thermal Efficiency}}$$

Recommended reference thermal efficiency values, according to primary fuel, are as follows:

Primary Fuel	Reference Thermal Efficiency (%)
Gaseous fuel	78
Distillate oil	81
Residual oil < 0.35% nitrogen	83
Residual oil ≥ 0.35% nitrogen	83
Wood/biomass	to be determined

If the actual thermal efficiency of a boiler is less than the reference thermal efficiency, a negative credit would result. However, it is not the intention of this Guideline to penalize inefficiency. Therefore only positive credits should be considered. Where a negative credit would result or no efficiency measures have been taken, the energy efficiency credits are assigned a value of one, and the recommended reference NO_X emission limits become the applied NO_X emission limits.

Heaters

For heaters, efficiency credits may be gained where stack losses have been reduced through the use of combustion air preheat as outlined on page 7. Credits for intermediate conditions could be determined by interpolation.

Efficiency Credits for Heaters at 10% Excess Air

Heater Exit Temperature (°C)	Combustion Air Preheat Temperature (°C)				
	100	200	300	400	500
1 300	1.07	1.17	1.25	1.32	1.37
1 200	1.06	1.15	1.22	1.29	1.34
1 100	1.05	1.14	1.21	1.27	1.32
1 000	1.05	1.13	1.19	1.25	1.30
900	1.04	1.12	1.18	1.24	1.29
800	1.04	1.11	1.17	1.22	1.27
700	1.04	1.11	1.16	1.21	1.26
600	1.04	1.10	1.16	1.20	1.25
500	1.03	1.09	1.15	1.19	
400	1.03	1.09	1.14		
300	1.03	1.09			
200	1.03				

Efficiency Credits for Heaters at 50% Excess Air

Heater Exit Temperature (°C)	Combustion Air Preheat Temperature (°C)				
	100	200	300	400	500
1 300	1.15	1.31	1.42	1.50	1.56
1 200	1.11	1.25	1.35	1.43	1.49
1 100	1.08	1.21	1.31	1.39	1.45
1 000	1.07	1.19	1.28	1.35	1.41
900	1.06	1.17	1.26	1.33	1.38
800	1.06	1.16	1.23	1.30	1.36
700	1.05	1.14	1.22	1.28	1.34
600	1.05	1.13	1.20	1.26	1.32
500	1.04	1.12	1.19	1.25	
400	1.04	1.12	1.18		
300	1.04	1.11			
200	1.04				

Efficiency Credits for Heaters at 100% Excess Air

Heater Exit Temperature (°C)	Combustion Air Preheat Temperature (°C)				
	100	200	300	400	500
1 300	1.67	1.84	1.90	1.92	1.94
1 200	1.28	1.53	1.65	1.72	1.77
1 100	1.17	1.39	1.52	1.60	1.66
1 000	1.13	1.32	1.44	1.52	1.58
900	1.11	1.27	1.38	1.46	1.52
800	1.09	1.23	1.33	1.41	1.47
700	1.08	1.20	1.30	1.38	1.44
600	1.07	1.18	1.27	1.34	1.40
500	1.06	1.16	1.25	1.32	
400	1.05	1.15	1.23		
300	1.05	1.14			
200	1.04				

The above efficiency credits are based on the reduction of fuel input that results from the corresponding level of combustion air preheat. The use of these efficiency credits will ensure that heaters operating with combustion air preheat will emit no more NO_x than similar heaters operating with no combustion air preheat.

The combustion air preheat efficiency credits are not related to the effect of combustion air temperature on the formation of NO_x emissions. At high combustion air temperatures, the formation of NO_x may increase at a greater rate than the increase in the emission limit obtained by applying the combustion air preheat efficiency credits. Consequently, a small number of heaters, characterized by high operating temperature and high combustion air temperature, would have emission rates above the Guideline emission limits, even if equipped with the best combustion modification emission control technology available at present. These units would require a reduction in combustion air preheat temperature, or the installation of post-combustion emission control equipment, to comply with the Guideline emission limits. Therefore, for such units the approach presented in the Guideline may discourage energy-efficient operation and increase the costs of emission control. Exempting units operating with high combustion air preheat from the Guideline emission limits and establishing emission limits in a different manner for these units should be considered.

v) Sources for Which Reference Emission Limits Are not Intended

It is recognized that reference emission limits may not be appropriate for all new boilers and heaters. Exceptions include sources designed to service unique needs and circumstances that affect their NO_x emission performance and that are unlikely to be duplicated in other locations. Low NO_x technologies for such sources have not advanced as rapidly as those applied to more standardized designs for boilers and heaters, and this situation is not expected to change in the immediate future. The use of coal to fire non-utility boilers and heaters in Canada is not common, and the practicality of reference NO_x emission limits has not been adequately assessed.

The new source reference emission limits contained in this Guideline are not intended for application to the following sources:

Pyrolysis heaters	(petrochemical sector)
Steam reformer heaters	(refining sector)
Steam cracking heaters	(refining sector)
Coke ovens	(steel sector)
Blast furnace stoves	(steel sector)
Reheat furnaces	(steel sector)
By-product fuel boilers	(multiple sectors)
Coal-fired boilers and heaters	(multiple sectors)
Chemical recovery boilers	(pulp and paper sector)

New source emission limits for the above sources should be developed on a case-specific basis through consultation between the proponent and the environmental authority having jurisdiction.

vi) Modified Boilers and Heaters

Emission limits for modified boilers and heaters should be developed on a case-specific basis through consultation between the proponent and the relevant provincial environmental authority. Practical considerations to be used in determining limits should include:

a) The use of new source emission limits as targets or starting points for consultation, recognizing that it may not be practical to achieve this level of emission control in all cases.

b) Recognition of the potential value of alternative approaches to reducing/minimizing NO_X emissions including:
- application of a bubble concept to a total facility;
- voluntary emission reduction plans;
- implementation of the Canadian Industrial Program for Energy Conservation (CIPEC) initiatives;
- NO_X emission trading.

vii) Measurement and Monitoring

a) NO_X Emission Verification

Schedule: The following schedule should be used to verify that the performance of NO_X control technologies is consistent with this Guideline.

Capacity		
(GJ/hr)	**(MMBtu/hr)**	**Verification Requirement ***
10.5 - 105	10 - 100	An initial verification test to be conducted at the time the new boiler or heater is commissioned.
105 - 264	100 - 250	Initial verification test plus an annual test of compliance with emission limits.
> 264	> 250	Initial verification test plus an annual test of compliance with emission limits plus some form of continuous verification.

*Notes

1. Verification should be conducted under normal operating conditions at an operating level of 75% to 100% of capacity.

2. Initial verification and individual annual testing should be conducted using an automated system meeting the monitoring methodology specified in EPS 1/RM/15, *Reference Method for the Monitoring of Gaseous Emissions from Fossil Fuel-Fired Boilers* (Environment Canada, 1990).

3. Continuous verification should be based on methods presented in Section 5 of the Background Document. These include:
   - continuous measurement (e.g., continuous emissions monitoring);
   - process capability methods;
   - surrogate methods;
   - parametric methods:
     - predictive emissions monitoring
     - compliance optimization

   The method(s) should be selected at the option of the operator and subject to approval by the regulatory authority.

Reporting: The findings of verification measurements should be reported on a "need to know basis" whereby data are kept by the operator for a prescribed period and subject to random audit by the regulating authority.

b) Energy Efficiency Verification

Proponents who intend to seek energy efficiency credits should refer to methods outlined in the *Combustion Handbook for Canadian Fuels* (*Volume I: Fuel Oils; Volume II: Gaseous Fuels*), by F. D. Friedrich and A.C.S. Hayden, Energy, Mines and Resources Canada, 1973; and the *Power Test Code for Steam Generating Units* (ASTM PTC 4.1-1964/ANSI PTC4.1-1974, reaffirmed 1991) by the American Society for Mechanical Engineers, United Engineering Center, 1991. Other equivalent methods may also be used.

Verification of energy efficiency should coincide with the verification of NO_X emissions as outlined in section vii) a).

Parts of the *Combustion Handbook* are reproduced in Appendix A to assist in the determination of thermal efficiency.

Appendix A

Examples of Methodology for the Determination of Thermal Efficiency[1]

Introduction

The thermal efficiency of a boiler or heater is a measure of the amount of energy extracted and utilized by the system in relation to the amount of energy in the fuel, measured at steady-state operation.

In other words, Thermal Efficiency = $\frac{\text{Heat Output}}{\text{Heat Input}^2}$

However, in most combustion systems, accurate measurement of heat output is not straightforward and can be prone to error.

It is usually more accurate (and easier) to use what is known as the indirect method to determine thermal efficiency. With this method, heat losses from the system are established and subtracted from 100% to arrive at the efficiency.

The prime heat losses to be concerned with are dry flue gas loss and hydrogen loss, as defined below.

Dry Flue Gas Loss Expressed in % of fuel heat input,[2] dry flue gas loss is the sensible heat in the dried (moisture-removed) flue gas. It is primarily dependent on the excess air and the difference in temperature between the flue gas and the combustion air.

Hydrogen Loss Expressed in % of fuel heat input,[2] hydrogen loss consists of the heat of evaporation of the water vapour in the flue gas due to the combustion of hydrogen in the fuel plus superheat. For a fuel with fixed hydrogen content, it depends only on flue gas temperature and combustion air temperature.

In general, the expression for thermal efficiency is as follows:

Thermal Efficiency	=	100%
	-	Dry Flue Gas Loss
	-	Hydrogen Loss

Examples

1. Natural Gas

Figures A1 and A2 represent graphical curves of dry flue gas loss and hydrogen loss for combustion of a typical Canadian natural gas. For a boiler operating at a carbon dioxide (CO_2) level of 8.2%, a stack temperature of 250°C, and a combustion temperature of 15°C, determine the thermal efficiency.

NOTE: Stack temperature and CO_2 concentration (or oxygen [O_2] concentration) are determined during the verification of NO_X emissions as outlined in section vii) a) of the Guideline.

From Figure A1, at CO_2 = 8.2%,
Total Combustion Air = 140% (Excess Air = 40%)

Stack Temperature - Combustion Air Temperature
= 250° - 15° = 235°C

1 Source: *Combustion Handbook for Canadian Fuels* (*Volume I: Fuel Oils; Volume II: Gaseous Fuels*), by F. D. Friedrich and A.C.S. Hayden, Energy, Mines and Resources Canada, 1973.

2. The heat input means the energy in the fuel, expressed in terms of the higher heating value, otherwise known as gross calorific value.

From Figure A1, going down the 235 line to 140% Total Air gives
Dry Flue Gas Loss = 9.8%

From Figure A2, with Stack Temperature = 250°C and Combustion Air Temperature = 15°C
Hydrogen Loss = 11.65%

Assuming no casing loss and no combustibles loss, Thermal Efficiency = 100.0% - 9.8% - 11.65% = 78.55%

2. Distillate Oil

Figures A3 and A4 represent graphical curves of dry flue gas loss and hydrogen loss for combustion of a typical Canadian distillate oil. For a boiler operating at a CO_2 level of 12.6%, a stack temperature of 250°C, and a combustion temperature of 25°C, determine the thermal efficiency.

NOTE: Stack temperature and CO_2 concentration (or O_2 concentration) are determined during the verification of NO_X emissions as outlined in section vii) a).

From Figure A3, at CO_2 = 12.6%,
Total Combustion Air = 120% (Excess Air = 20%)

Stack Temperature - Combustion Air Temperature = 250° - 25° = 225°C

From Figure A3, going down the 225 line to 120% Total Air gives
Dry Flue Gas Loss = 8.6%

From Figure A4, with Stack Temperature = 250°C and Combustion Air Temperature = 25°C
Hydrogen Loss = 7.57%

Assuming no casing loss and no combustibles loss, Thermal Efficiency = 100.0% - 8.6% - 7.57% = 83.63%

3. Residual Oil

Figures A5 and A6 represent graphical curves of dry flue gas loss and hydrogen loss for combustion of a typical Canadian residual oil. For a boiler operating at a CO_2 level of 12.0%, a stack temperature of 200°C, and a combustion temperature of 25°C, determine the thermal efficiency.

NOTE: Stack temperature and CO_2 concentration (or O_2 concentration) are determined during the verification of NO_X emissions as outlined in section vii) a) of the Guideline.

From Figure A5, at CO_2 = 12.%,
Total Combustion Air = 130% (Excess Air = 30%)

Stack Temperature - Combustion Air Temperature = 200° - 25° = 175°C

From Figure A5, going down the 175 line to 130% Total Air gives
Dry Flue Gas Loss = 7.5%

From Figure A6, with Stack Temperature = 200°C and Combustion Air Temperature = 25°C
Hydrogen Loss = 6.52%

Assuming no casing loss and no combustibles loss, Thermal Efficiency = 100.0% - 7.5% - 6.52% = 85.98%

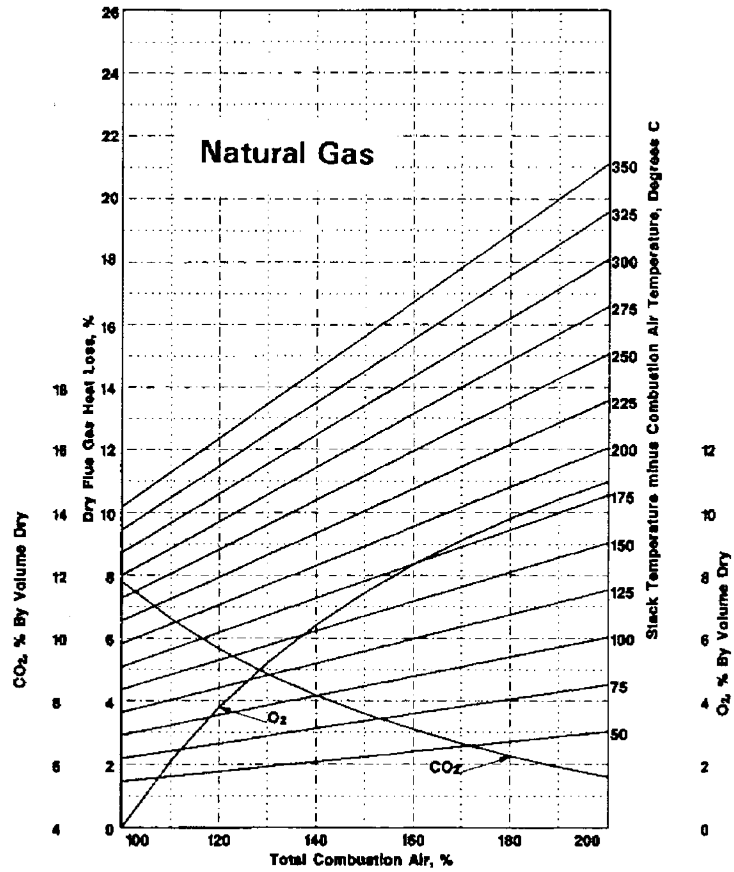


Figure A1 - Dry Flue Gas Loss for a Range of Temperature Differentials

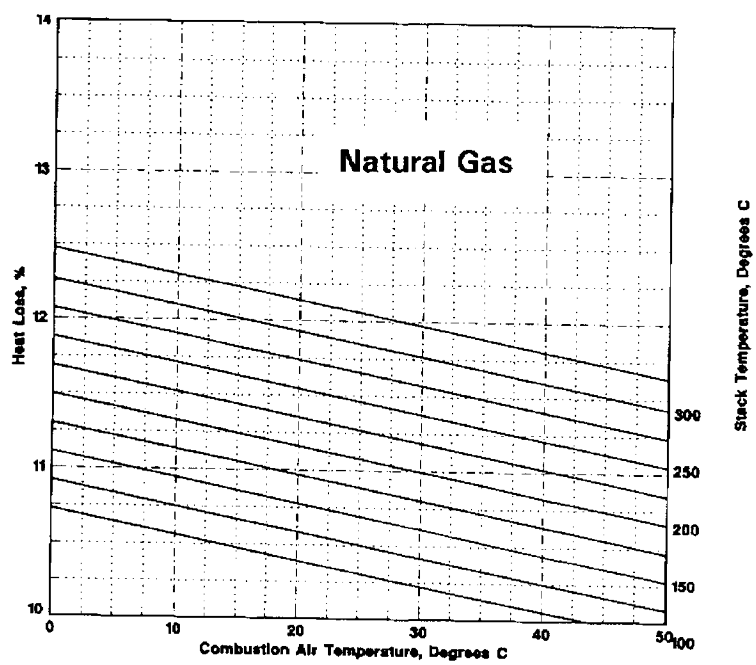


Figure A2 - Hydrogen Loss for a Range of Stack Temperatures

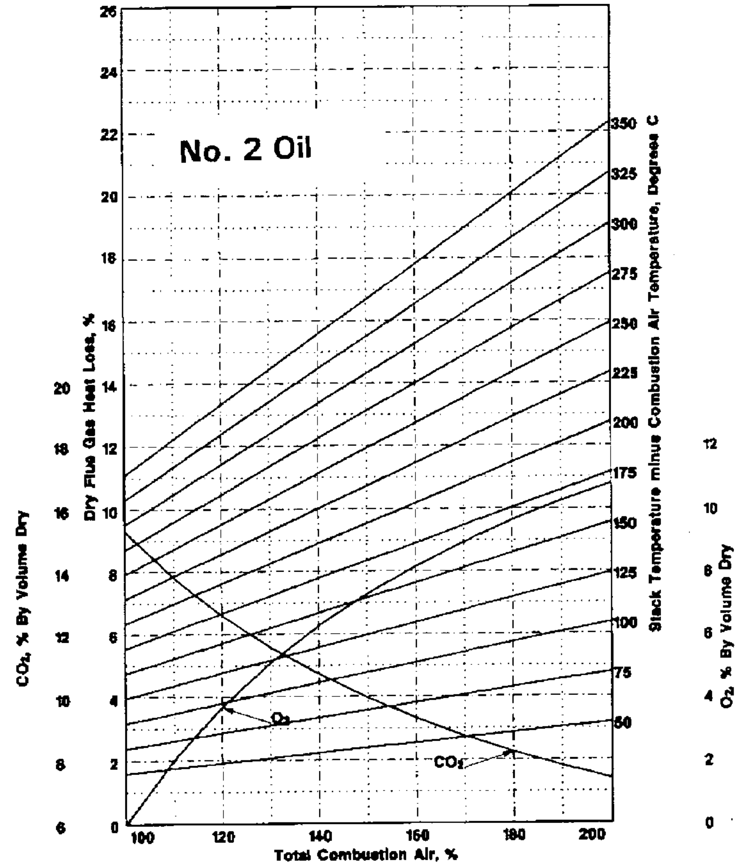


Figure A3 - Dry Flue Gas Loss for a Range of Temperature Differentials

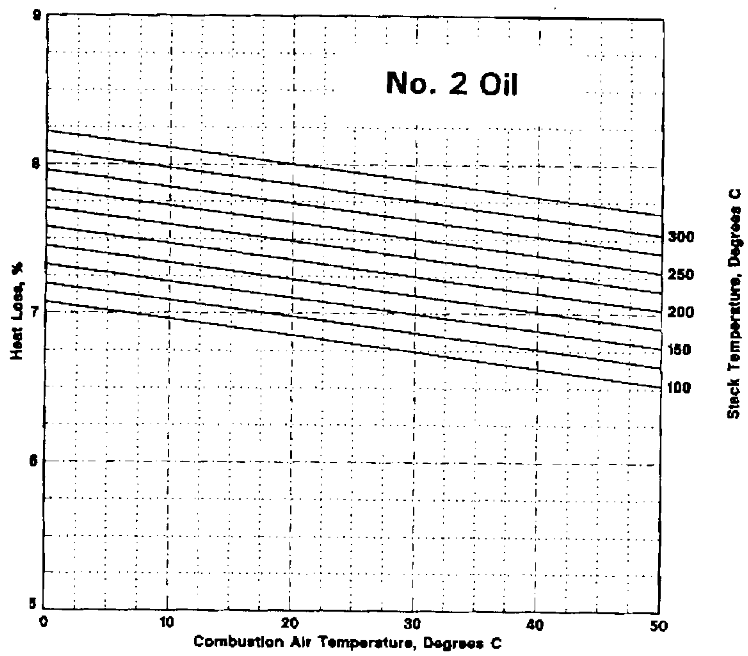


Figure A4 - Hydrogen Loss for a Range of Stack Temperatures

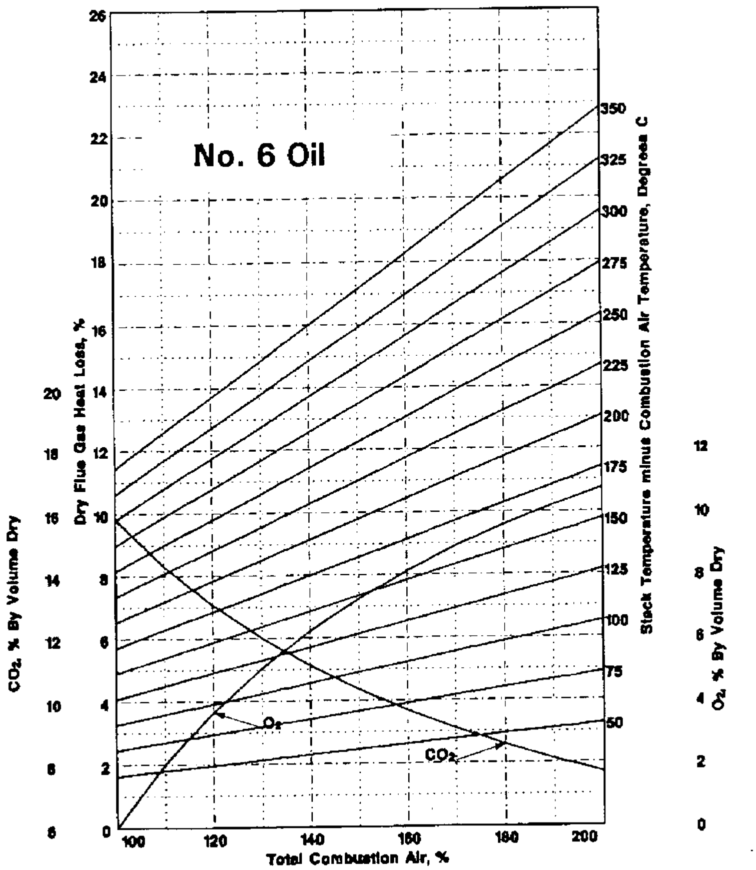


Figure A5 - Dry Flue Gas Loss for a Range of Temperature Differentials

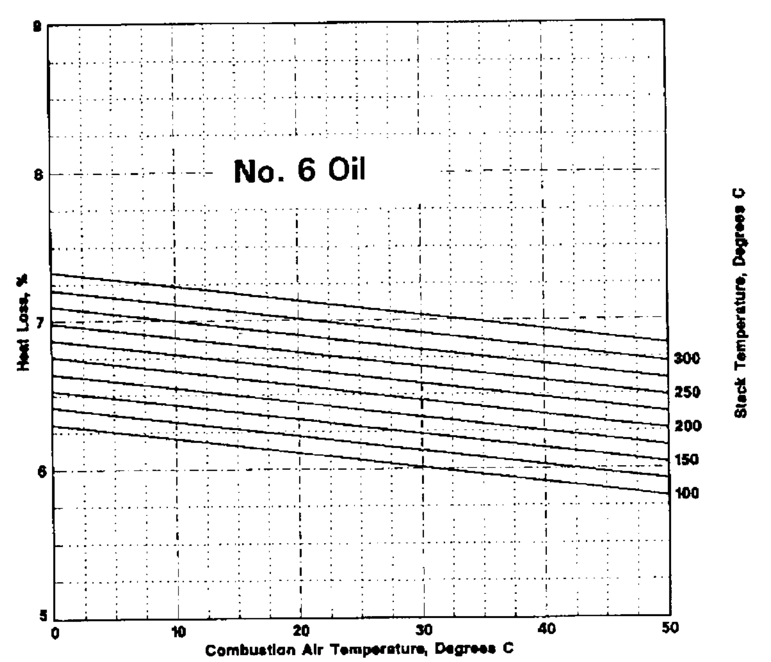


Figure A6 - Hydrogen Loss for a Range of Stack Temperatures

Appendix B

Conversion Factors

Multiply	by	to obtain
Boiler Horsepower (BHP)	0.0335	Million British Thermal Units per Hour (MMBtu/hr) (output)
Gigajoules per hour (GJ/hr)	0.9483	Million British Thermal Units per Hour (MMBtu/hr)
Megawatts (MW)	3.414	Million British Thermal Units per Hour (MMBtu/hr)
Grams NO_X (as NO_2) per Gigajoule (g/GJ) (Natural Gas)	1.907	Parts per million by volume* (ppmv) NO_X as (NO_2) @ 3% O_2
Grams NO_X (as NO_2) per Gigajoule (g/GJ) (Light Fuel Oil)	1.808	Parts per million by volume* (ppmv) NO_X as (NO_2) @ 3% O_2
Grams NO_X (as NO_2) per Gigajoule (g/GJ) (Heavy Fuel Oil)	1.808	Parts per million by volume* (ppmv) NO_X as (NO_2) @ 3% O_2
Grams per Gigajoule (g/GJ)	0.00233	Pounds per Million British Thermal Unit (lb/MMBtu)

* dry, at 25 °C and 101.32 kPa

Appendix C

Working Group #1 Members

Industry

Jake Brooks	Independent Power Producers Society of Ontario
Jim Campbell	Canadian National Railways
Gary Deans	Dofasco Incorporated (Canadian Steel Producers Association)
Tom Hewitt	Imperial Oil (Canadian Petroleum Products Institute)
King Ma	Novacor Chemicals (Canada) Limited (Canadian Petroleum Products Institute)
Ron Polidori	Miura Boiler Company, Limited (Canadian Boiler Society)
Claude Roy(1)	Canadian Pulp and Paper Association
Al Schuldt	Stelco Incorporated (Canadian Steel Producers Association)
Garry Scott	Dow Chemical Incorporated (Canadian Chemical Producers Association)
Lorne Smith	Waterloo Manufacturing Company, Limited (Canadian Boiler Society)
Murray Smith	Union Gas Limited (Canadian Gas Association)
Hugh Sprague	Stelco Incorporated (Canadian Steel Producers Association)
Brent Steele	Dofasco Incorporated (Canadian Steel Producers Association)
Bill Van Nieuwenhuizen	Babcock and Wilcox (Canadian Boiler Society)

Environmental Non-Governmental Organization

Bruce Walker	STOP

Provincial and Regional Government

Kamal Bhattacharyya	Greater Vancouver Regional District
Denis Perras (2)	Saskatchewan Environment Resource Management
Randy Dobko	Alberta Environmental Protection
Scott Grant	Ontario Ministry of the Environment
Doug Harper	Ontario Ministry of the Environment
Richard Johns	Manitoba Environment
Jean Lavergne	Ministère de l'Environnement et de la Faune, Québec
Jane MacNeill (3)	Nova Scotia Department of Environment
John Nwoke	Newfoundland Environment and Labour
Virginia Bulgar	P.E.I. Energy and Forestry
Denis Marquis (4)	New Brunswick Department of Environment
Frank Witthoeft (5)	British Columbia Ministry of Environment

Federal Government

Michael Burke	Natural Resources Canada
A.C.S. Hayden	Natural Resources Canada
Geoff Ross	Environment Canada
Kin Mah	Environment Canada

(1) Replaces Mike Frost
(2) Replaces Earl Craig
(3) Replaces David Blair
(4) Replaces Michael Murphy
(5) Replaces Jai Qu Zhang

Appendix D

Background Document for the Development of a National Guideline for NO_X Emissions from New or Modified Commercial/Industrial Boilers and Heaters

Executive Summary

As part of the Canadian Council of Ministers of the Environment (CCME) Management Plan for Nitrogen Oxides (NO_X) and Volatile Organic Compounds (VOCs), Environment Canada is to coordinate a multistakeholder consultative process, referred to in the Plan as Initiative N306, to develop national emission guidelines for new and modified commercial/industrial boilers, heaters and cement kilns. Under N306, three working groups were formed to deal with (1) fossil fuel-fired boilers and heaters, (2) wood and biomass-fired boilers and (3) cement and lime kilns. This report summarizes the technical background document prepared by working group 1 (fossil fuel-fired boilers and heaters). The full technical background report is available from Environment Canada on request.

The CCME NO_X/VOCs Management Plan (1990) estimates that 8% or 145 kilotonnes per year (kt/yr) of total national NO_X emissions originated from commercial/industrial boilers and heaters in 1985. This was forecast to increase to 10% of the total or 207 kt/yr by 2005. Achievement of the Plan's target NO_X reductions would entail a reduction of 66 kt/yr or 32% from the forecast year 2005 emissions from commercial/industrial boilers and heaters. This would result from a combination of the new boiler and heater (preventive) initiative N306 and the existing boiler and heater (remedial) initiative N603. Accordingly, the scope of this background document was expanded to address both new and existing boilers and heaters, including heaters in the iron and steel sector (initiative N604). The information on existing boilers and heaters is intended to support provinces implementing remedial measures, whereas only new and modified boilers and heaters are to be addressed in the N306 guideline.

Included in this report is a description of the characteristics and uses of the commercial/industrial boilers and heaters (section 2), followed by a national inventory according to capacity, sector, fuel type, fuel utilization and NO_X emission rate, which was used to establish where reduction options can be effectively applied (section 3). NO_X emission reduction technology options are reviewed and assessed in terms of effectiveness, cost and impact on energy consumption and other pollutants (section 4). Options for verifying emission reduction performance, and for the form of NO_X emission limits (input-based, output-based) are considered (section 5). NO_X emission standards in other jurisdictions (Europe and the United States) are also examined (section 6). Possible emission reduction approaches are assessed (section 7). Based on the preceding sections, the rationale (section 8) for the recommendations (section 9) by working group 1 for the Guideline are presented.

Description and Industrial Usage of Boilers and Process Heaters

Purchased fuels commonly used in boilers and fired heaters include natural gas, #2 fuel oil and #6 fuel oil. These fuels conform to certain specifications stipulated by the Canadian General Standards Board. Coal is also used in Canada, but less often. Biomass-fired units are dealt with by working group 2. Other fuels are produced as by-products of industrial processes and are generally consumed on site in the refining, petrochemical, pulp and paper and iron and steel sectors. The properties of a by-product fuel can vary substantially over time, so that equipment utilizing these fuels must be designed with sufficient flexibility.

Fossil fuel-fired boilers are defined as any device used to produce steam or hot water using fossil fuel combustion as a heat source. In this document, boilers fired with purchased fuels such as natural gas, #2 fuel oil or #6 fuel oil are referred to as *conventional* boilers. All of the industrial sectors considered utilize conventional boilers to some extent. Other types of boilers that fire by-product streams are referred to as *specialty* boilers.

Industry-specific fuels, boilers and heaters, developed to accommodate the different needs of each sector, were examined.

1. *Commercial, Institutional and Manufacturing Sectors*
   These sectors fire mainly conventional boilers with either natural gas or #2 fuel oil.

2. *Oil-Refining Sector*
   Larger conventional boilers are found in the refineries themselves. The fuels used are predominantly refinery fuel gas and residual fuel oil. Steam is also generated by fluid catalytic cracking unit waste heat and CO boilers firing petroleum coke. Smaller boilers are used in other facilities operated by the oil companies, such as distribution terminals, large retail outlets and large office buildings. The fuel used in these smaller units would be #2 fuel oil or natural gas, if it is available. In the upstream oil sector, the use of thermal enhanced oil recovery steam generators, mainly fuelled by natural gas, is expected to grow significantly as production of heavy oil increases.

   Significant differences between boiler and process heater designs arise because of the different properties of process fluids compared with water. Refinery heaters are used in the following applications:
   - preheating feed to a reactor or a fractionation column;
   - reboiling of a fractionation column;
   - heating a transfer fluid in a circulating heating belt;
   - reaction heaters.

3. *Chemical and Petrochemical Sector*
   In general, with the possible exception of olefin plants, plants in this sector produce significantly less by-product fuel and rely more on purchased natural gas. Steam requirements in this sector are satisfied by process waste heat sources, flue gas waste heat and utility boilers. The contribution from each source varies considerably depending on the type of chemical or petrochemical complex. In ammonia and ethylene plants, for example, process and flue gas waste heat provides a significant percentage of the normal steam requirements. Conventional boilers, however, are still required for start-up and emergency standby. Almost all the fired heaters in this sector are found in petrochemical rather than chemical applications. The configuration and use of these heaters are, for the most part, the same as in the oil refining sector. Two notable exceptions are:
   - pyrolysis furnaces for olefins production, and
   - steam reformers for producing hydrogen from natural gas or light hydrocarbons.

4. *Pulp and Paper Sector*
   By-product fuels in the pulp and paper industry are bark and wood chips and the lignin in black liquor. Most boilers in this industry are specialty boilers fuelled by wood and wood products such as black liquor in combination with purchased fuels such as #6 fuel oil. Some conventional boilers are used in limited capacity.

5. *Iron and Steel Sector*
   The integrated steel producers must use a variety of fuels. The important by-product fuels are coke oven gas, blast furnace gas, and basic oxygen furnace offgas. The source of the energy contained in these by-product fuels is coal. Supplementary fuels are natural gas and #6 fuel oil.

   Fuel-use flexibility requires burner and combustion chamber design for multifuel firing. These burners are unique to the industry, and their performance is often compromised to accommodate fuels with different and widely varying combustion characteristics. Redesigning and developing new burners for these applications to reduce NO_x emissions is a challenge not yet undertaken by burner manufacturers.

Roughly 30-40% of the fuel consumption reported for the iron and steel integrated mills is ascribed to boilers. Small conventional boilers fired with purchased fuels are used by some of the mini mills and steel specialty producers. The large integrated steel mills use conventional boilers only to a limited extent and in facilities located outside the major processing areas. Specialty boilers include those whose main fuel is blast furnace gas. Coke oven gas is also widely used, and purchased fuel, which is brought in to keep the fuel system in balance, makes up the remainder. Blast furnace gas is a difficult fuel to deal with because of its low heating value and low pressure. This has led to the development of boilers specific to the iron and steel industry. Other specialty boilers are fired with basic oxygen furnace offgas.

Heaters in this sector differ radically from those discussed above. Outlined below are the major differences that may result from processes specific to the iron and steel sector:

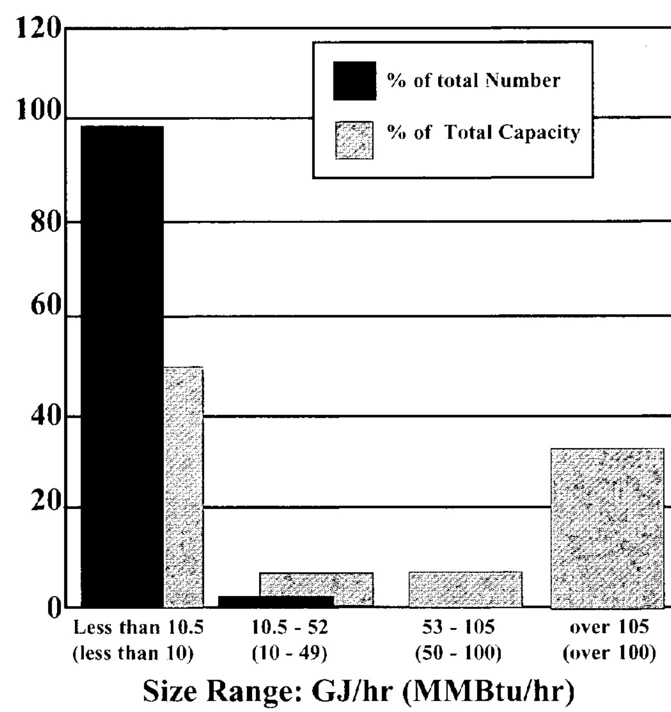
- some heaters heat solid materials (e.g., coke in coke ovens, steel in reheat and heat-treat furnaces);
- some heaters entail batch processes rather than continuous processes (e.g., coke ovens, blast furnace stoves, soaking pits);
- some heaters are direct-fired (e.g., reheat furnaces);
- process temperatures in these heaters are very high.

Three iron and steel processes utilizing fired heaters account for about 60% of the fuel consumption in this sector. These are cokemaking, ironmaking and hot rolling, each of which consumes about the same quantity of fuel.

Inventory of Boilers and Heaters

There are estimated to be between 350 000 and 600 000 active non-utility boilers in Canada with a total combined heat input capacity of approximately 1 160 000 gigajoules per hour (GJ/hr) (1 100 billion British thermal units per hour). It is apparent from Figure D1 that approximately 98% of boilers in Canada, which make up 50% of the total boiler capacity, have heat input capacities of less than 10.5 GJ/hr (10 million British thermal units per hour [MMBtu/hr]). In addition, units with capacities greater than 105 GJ/hr (100 MMBtu/hr) represent less than 0.5% of the total number of boilers but approximately 35% of the total capacity.

Figure D1 — Distribution of Boilers in Canada by Size, Percent of the Number of Boilers and Percent of Total Capacity

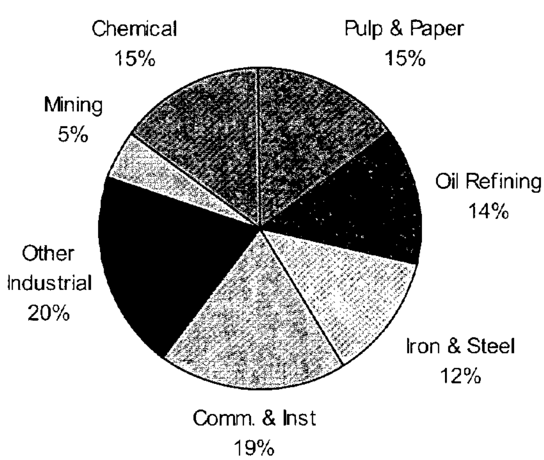


A number of industrial sectors contribute to NO_x emissions from fossil fuel firing in boilers *and* fired heaters. Figure D2 indicates that, for 1991, the largest contributors of NO_x emissions were the "Commercial & Institutional" and "Other Industrial" sectors, with a combined total of approximately 39%. The majority of boilers in these two sectors are in the less than 10.5 GJ/hr (10 MMBtu/hr) range.

Table D1 — Uncontrolled Emission Factors for Estimating Boiler NO_x Emissions

Fuel Type	Capacity (GJ/hr)	Capacity (MMBtu/hr)	Uncontrolled NO_x Emission Factor Range (tonnes/petajoule)	Uncontrolled NO_x Emission Factor Weighted Average (tonnes/petajoule)
Natural Gas	< 10.5	< 10	29 - 54	43
	10.5 - 105	10 -100	13 - 133	54
	> 105	>100	17 - 194	97
Distillate Oil	< 10.5	< 10	49 - 70	59
	10.5 - 105	10 -100	34 - 106	65
	> 105	> 100	77 - 99	92
Residual Oil	< 10.5	< 10	132 - 167	145
	10.5 - 105	10 - 100	86 - 340	145
	> 105	> 100	133 - 258	166

Figure D2 — NO_X Emissions in Canada by Sector for Fossil Fuel-Fired Boilers and Heaters (1991)



NO_X emission estimates are based upon the use of NO_X emission factors for boilers (summarized in Table D1) and fossil fuel usage data from StatsCan.

NO_X emissions (as nitrogen dioxide) for fossil fuel firing in boilers and fired heaters for all sectors were estimated to be 161 kt for 1991. However, this is a "weighted average" estimate between a relatively broad range of NO_x emission estimates (98-326 kt) that depend on the selection of emission factors.

NO_X Emission Reduction Options

A number of NO_X control methods are considered for application to boilers and heaters. These can be categorized as combustion controls or post-combustion controls. Combustion controls attempt to prevent NO_X formation by controlling flame temperature, reducing the oxygen level at critical points in the combustion, and reducing the residence time during which the nitrogen is oxidized. Combustion control methods considered in this study include:

- low excess air;
- reduction of combustion air temperature;
- low NO_X burners;
- ultra-low NO_X burners;
- flue gas recirculation;
- water or steam injection;
- staged combustion;
- reburning.

Post-combustion processes remove NO_x after its formation by converting it to nitrogen gas and oxygen. Possible technologies include:

- selective non-catalytic reduction;
- selective catalytic reduction;
- combined sulphur oxides/nitrogen oxides (SO_x/NO_x) control methods:
  - wet scrubbing,
  - irradiation,
  - adsorption,
  - alkali injection,
  - catalytic methods.

Other more direct NO_x reduction methods include fuel switching and energy conservation.

A summary of the effectiveness of both combustion and post-combustion controls, based on data reported in the literature, is given in Table D2. With the exclusion of low excess air control technology, the minimum overall effectiveness is 50%, 45% and 35% for natural gas, distillate oil and residual oil respectively.

Table D2 — Approximate Achievable Effectiveness of NO_x Control Technologies

Control Measure	Overall Effectiveness (%)		
	Natural Gas	Distillate Oil	Residual Oil
Low Excess Air	20	18	16
Low NO_x Burners			
- Air-staged	50	45	37
- Fuel-staged	60	52	37
- Ultra-Low NO_x Burners	75	74	73
- Radiant	85	-	-
Flue Gas Recirculation	57	49	35
Flue Gas Recirculation and Low NO_x Burners	70	60	45
Selective Non-catalytic Reduction	50	50	50
Selective Catalytic Reduction	80	80	90

As indicated in Table D3, the cost effectiveness of combustion controls for new boilers and heaters is relatively low at less than $600 per tonne of NO_x removed. The cost effectiveness of post-combustion controls is dramatically higher.

Table D3 — Cost Comparison of NO_x Controls for New and Retrofitted Boilers and Heaters

Control Measure	Capital Cost ($K)		Cost Effectiveness ($/tonne)	
	For New Boiler/Heater	For Retrofit	For New Boiler/Heater	For Retrofit
Low NO_x Burners	54.5	329.4	309	3 821
Ultra-Low NO_x Burners	92.0	366.9	418	3 298
Flue Gas Recirculation	64.0	243.4	557	3 006
Selective Non-catalytic Reduction	363.6	424.3	5 451	7 168
Selective Catalytic Reduction	708.1	1 365.8	3 993	9 219

From the evidence in Tables D2 and D3, it was concluded that the NO_x reductions presented in Table D4 are achievable at a reasonable cost:

Table D4 — NO_X Reduction Achievable at Reasonable Cost

Fuel	% NO_X Reduction	Technologies	% NO_X Reduction	Technologies
Natural Gas	50	Low NO_X Burners	70	Ultra-Low NO_X Burners or Flue Gas Recirculation & Low NO_X Burners
Distillate Oil	40	Low NO_X Burners	60	Ultra-Low NO_X Burners or Flue Gas Recirculation & Low NO_X Burners
Residual Oil	25	Low NO_X Burners	45	Ultra-Low NO_X Burners or Flue Gas Recirculation & Low NO_X Burners

In Table D4, the NO_X reduction effectiveness of low NO_X burners for distillate and residual oil was lowered compared to values derived from the literature (see Table D2). This was done in response to stakeholder concerns relating to uncertainties in the data available on the performance of this technology for these fuels.

Options for Verifying Emission Reduction Performance

Verification is intended to provide assurance to industry, regulators and the public that control of emissions is being achieved and maintained. For the purposes of N306, verification is defined as an ongoing activity addressing the objective that NO_X emissions are maintained at or below the applicable emission limit, as outlined in the Guideline. Note that verification differs from emission monitoring, which involves quantifying actual emissions and therefore places greater demands on data quality.

The following verification options were examined:

- Direct Measurement Methods
  - Periodic measurement using manual methods;
  - Periodic measurement using automated methods;
  - Continuous measurement.
- Process Capability, Surrogate and Parametric Methods
  - Process Capability: based on quality assurance and quality control principles applied to NO_X reduction technologies;
  - Surrogate: based on measurements of routine process conditions;
  - Parametric: ranging from simple linear algorithms to "self -taught" expert systems.

The advantages and disadvantages of the above options relate primarily to their costs and the quality and quantity of data generated. Periodic measurement may be inexpensive but leaves emission performance unverified in the intervals between tests. Continuous measurement (e.g., continuous emissions monitoring [CEM]) is costly but capable of providing a high (continuous) quantity and quality of data. The process capability, surrogate and parametric options may provide a comparable quantity of data, but the quality is likely to vary with the cost of the system. Advanced parametric systems are expected to provide high-quality data but at costs approaching those of CEM. Process capability, surrogate and simple parametric systems are expected to be less expensive. Although the data quality of these systems is not as high as that of CEM, these options may be appropriate for verification that imposes less stringent demands than emission monitoring.

The frequency of periodic measurement and the averaging times for any of the continuous options influence the ability to achieve an emission limit. Frequent periodic measurement (e.g., monthly) or a continuous system with short averaging times (e.g., hourly) will make it more difficult to meet a given emission limit than will less frequent measurement (e.g., yearly) or longer averaging times (e.g., monthly). These aspects of verification must be determined in conjunction with the setting of the emission limits.

The form of an in-stack emission limit will have an impact on the monitoring requirements. Emissions based on the mass of NO_X per unit of energy input can be established by direct measurement of emission concentration. However, this does not encourage or credit the reduction of NO_X emissions, or other emissions, achieved through energy efficiency improvements. It is recognized that energy efficiency improvements may lower *net* NO_X emissions by reducing the quantity of fuel consumed even though the *rate* of NO_X emissions, on an energy input basis, may remain constant or increase. In an effort to address this issue, alternative forms of stack emission limits were considered:

- emission limits in the form of mass of NO_X emitted per unit of energy output from the boiler (output-based);
- an output-based limit as above but considering overall system efficiency;
- emission limits in the form of mass of NO_X emitted per unit of product output;
- input-based emission limits that can be adjusted according to credits for the measured efficiency of the boiler or heater.

Emission Standards in Other Jurisdictions

This section examines emission limits that have been implemented, generally as legal requirements, in Europe and the United States. It does not examine the ambient environmental quality concerns that the standards address nor the level of enforcement. Therefore the section provides an indication of the emission levels that are technically feasible but should not be taken as an indication of the emission limits which are appropriate for dealing with current ambient environmental quality concerns in Canada.

NO_X emission limits vary widely among different countries in Europe and within the United States. Many European countries have NO_X reduction obligations under the United Nations Economic Commission for Europe Convention on Long-Range Transboundary Air Pollution, which was originally signed in 1979. Recent additions have made it necessary for member countries to develop policies and strategies which will limit NO_X emissions to 1987 or previous levels. Furthermore, the European Community (EC) has issued a directive that is designed to achieve a global NO_X emission reduction of 10% by 1994 and 30% by 1998. These standards are the minimum requirements for the EC, and some countries have chosen to submit to these requirements only. However, most countries are pursuing more aggressive NO_X reductions and have adopted more stringent standards.

In the United States, the Environmental Protection Agency (EPA) established new source performance standards for industrial-commercial-institutional boilers in 1986 (amended 1989). Under the Clean Air Act Amendments of 1990, the EPA is required to review and revise these standards and is currently in the process of doing so. Much of the responsibility for the implementation of NO_X standards has been delegated to individual states. Twenty-eight states have levels of ozone non-attainment high enough to require action. The classifications for ozone non-attainment range from marginal to extreme and any state with an area classified as moderate or higher is required by the Clean Air Act Amendments of 1990 to implement reasonable available control technology (RACT). The results of this review are summarized in Table D5. Standards included in Table D5 include the more stringent European standards and those of the South Coast district of California, which has the most stringent standards in the United States. The Louisiana standards were selected as "representative" of NO_X RACT standards.

Table D5 — NO_X Emission Standards for Boilers in Other Jurisdictions

Country	Fuel	Capacity (GJ/hr)	Capacity (MMBtu/hr)	New Source NO_X Standard (g/GJ)	Existing Source NO_X Standard (g/GJ)
Austria	Natural Gas	10.5 - 1 080	10 - 1 024	25 - 50	38 - 76
	Distillate Oil	10.5 - 180	10 - 171	66	-
	Residual Oil	10.5 - 180	10 - 171	119	-
Germany	Natural Gas	36 - 1 080	34 - 1 024	25 - 50	38 - 88
	Distillate Oil	18 - 180	17 - 171	66	66
	Residual Oil	3.2 - 180	3 - 171	80	119
Netherlands	Natural Gas	> 0	> 0	15	15
	Oil	< 1 080	< 1 024	29	29
		> 1 080	> 1 024	80	80
Switzerland	Natural Gas	3.2 - 1 080	3 - 1 024	-	50
	Distillate Oil	3.2 - 1 080	3 - 1 024	-	66
	Residual Oil	180 - 1 080	171 - 1 024	80	80
U.S. (EPA)	Natural Gas	> 105	> 100	43 - 86	-
	Distillate Oil	> 105	> 100	43 - 86	-
	Residual Oil	> 105	> 100	130 - 170	-
Louisiana	Gas	preheat	preheat		
		< 98°C	< 200°F	-	43 - 86
		93 - 204°C	200 - 400°F	-	64 - 103
		> 204°C	> 400°F	-	86 - 120
	Oil			-	86 - 129
California (South Coast)	All Fuels	> 5.3	> 5	22	22

Possible Emission Reduction Approaches

Although the primary mandate of N306 was to develop an emission guideline for new and modified boilers and heaters, it was agreed at the outset to assemble technical supporting information for existing boilers, heaters and related equipment. This was intended to assist provinces dealing with remedial measures in ozone non-attainment areas. Therefore N306 working group 1 evaluated a variety of possible approaches for both the new and existing source initiatives for fossil fuel-fired commercial/ industrial boilers and heaters in terms of their possible applicability, form of requirements and implementation. Both the "top-down best available control technology" approach and the "in-stack limits for existing boilers and heaters" were excluded from further consideration because they were judged inferior in a number of respects to various alternatives. No one option was consistently rated as advantageous or disadvantageous across a majority of the criteria. Therefore, it was concluded that, where remedial measures are to be taken, the approach to minimizing emissions from boilers and heaters should not involve an either/or selection of alternatives but should involve a combination of approaches that could be implemented as a package. These are presented in the final section of this Executive Summary, under "Recommendations."

Considerations in the Development of a National New Source Guideline

This section draws together the various factors discussed in the previous sections to illustrate the rationale for the recommendations for development of the Guideline.

1. *Capacity Limit*
The issue of upper and lower limits on the thermal capacity of boilers and heaters to be addressed by the Guideline has considerable impact on the practicality and benefits of its implementation. The following issues are of particular concern:

- Cost/effectiveness: Based on the boiler inventory outlined previously, a lower capacity limit of > 10.5 GJ/hr (10 MMBtu/hr) would mean that the total boiler capacity under the Guideline was large in relation to the total number of boilers to be addressed. Any further lowering of the capacity limit would mean a small increase in total boiler capacity relative to the large number of additional boilers to be addressed.
- Demand on provincial resources: As the lower capacity limit is reduced from > 105 GJ/hr (100 MMBtu/hr) to > 10.5 GJ/hr (10 MMBtu/hr), the increase in the number of new boilers and heaters to be addressed each year is relatively small. Any further reduction in the capacity limit results in a large increase in the number of new boilers and heaters to be addressed.
- Consistency with other NO_X reduction options: The recommended design standard for small boilers and heaters would most likely address only boilers and heaters smaller than 10.5 GJ/hr (10 MMBtu/hr) (see Item 3 of the "package" outlined in the Recommendations section of this Executive Summary). By selecting 10.5 GJ/hr (10 MMBtu/hr) as the lower capacity limit for the N306 Guideline, there would be no "gap" in coverage.

2. *Emission Limits for New Boilers and Heaters*
The following emission factors presented in Table D6 are assumed to represent the average performance of uncontrolled boilers and heaters:

Table D6 — Average Performance of Uncontrolled Boilers and Heaters

Capacity		NO_X Emission Limit (g/GJ)		
(GJ/hr)	(MMBtu/hr)	Gaseous Fuel	Distillate Oil	Residual Oil
10.5 - 105	10 - 100	54	65	145
> 105	> 100	97	92	166

Applying the emission reduction levels from Table D4 yields the achievable emission limits in Table D7:

Table D7 — Achievable Emission Limits

Capacity		NO_X Emission Limit (g/GJ)		
(GJ/hr)	(MMBtu/hr)	Gaseous Fuel	Distillate Oil	Residual Oil
10.5 - 105	10 - 100	16 - 27	26 - 39	80 - 109
> 105	> 100	29 - 49	37 - 55	91 - 125

These possible ranges of derived emission limits were compared with other relevant data (draft guidelines for federal boilers, CANMET data, U.S. EPA data) and the emission limits in other jurisdictions. The derived emission limits at the lower ends of these ranges were in most cases felt to be too stringent because they were not well supported by demonstrated performance of boilers in Canada and emission limits in other jurisdictions. Less stringent limits are recommended for larger boilers and heaters in consideration of the higher emission factors reported for these capacities. The achievable emission limits for residual oil are strongly influenced by the nitrogen content of the oil.

Based on the above findings and considerations, and except as noted below,[1] consensus was reached among working group members that the emission limits set out in Table D8 should be recommended for the Guideline.

3. *Approach to Modified Boilers and Heaters*
   The following possible options for defining "modified" were examined:
   - any change that would increase emissions more than some percentage above the baseline;
   - any change whose cost would exceed some percentage of the capital cost or replacement cost of the equipment;
   - any change to or replacement of equipment that would directly affect environmental performance.

   Alternatives for applying the Guideline to modified boilers and heaters included:
   - applying new source emission limits to modified sources;
   - applying less stringent emission limits to modified sources;
   - providing for case-specific limits for modified sources, using the new source limits as examples or "targets";
   - inserting a clause in the Guideline such that by some future date, or after some years of operation, all boilers and heaters would be considered as "new."

Table D8 — Recommended Emission Limits

Capacity		**NO_X Emission Limit (g/GJ)**			
(GJ/hr)	**(MMBtu/hr)**	**Gaseous Fuel**	**Distillate Oil**	**Residual Oil < 0.35% Nitrogen**	**Residual Oil ≥ 0.35% Nitrogen**
10.5 - 105	10 - 100	26	40	90	110
> 105	> 100	40	50	90	125

1 Bruce Walker of STOP did not support the consensus view, maintaining that the recommended NO_X limit for gaseous fuels should be 22 g/GJ rather than 26 g/GJ for units with capacities between 10.5 and 105 GJ/hr.

All of the above alternative definitions and applications have advantages and disadvantages. Since some are already part of some provinces' policies on modified sources, selecting one option for the Guideline may conflict with provincial policy. In addition, owners of boilers and heaters do not have the same degree of flexibility in meeting quantitative emission limits on modified sources as they do on new sources. Costs of emission reductions are expected to be much higher and more variable for modified sources. Thus, fixed, quantitative emission limits for modified sources may be problematic.

It was recommended that the Guideline should:

- contain a discussion of the objective and rationale for dealing with modified sources, and the possible definitions of "modified";
- recommend approaches to the definition of "modified." However, the Guideline should recognize that the mandate for defining "modified" remains with the implementing province;
- recommend that the emission limits for new sources be used as "targets" for modified sources, acknowledging that it may not be practical to achieve this level of control in all cases. Although emission levels may be case-specific, provinces should ensure that modified boilers and heaters will achieve significant reductions in NO_x emissions.

4. *Verification of Emission Limits*

The working group devoted considerable effort to the assessment of verification needs, frequency and methods. The objective was to avoid, if possible, the arbitrary, up-front application of verification requirements to all boilers and heaters commonly seen in existing emission standards. It was postulated that a statistical approach could be developed that would determine the verification requirements for any individual unit based on the magnitude and variability of its emissions. This would provide a certain level of confidence that emissions were being maintained at or below the guideline emission limit by assigning more strict verification requirements to units having higher and more variable NO_x emissions and less strict requirements to units having lower and more consistent emissions. This would provide the incentive of reduced monitoring costs if improved NO_x control performance can be demonstrated.

Although the statistical approach was agreed to have merit, it was ultimately felt to be too complex. Instead, it was agreed to assign straightforward verification requirements in the Guideline based on simplicity and the following considerations:

- the stringency of verification requirements should be based on the capacity (and thus the potential magnitude of emissions) of the boiler or heater;
- for lower capacity units, the cost of continuous verification or even regular periodic monitoring may not be justified by the resulting improvement in emission control;
- for continuous verification, there should be the flexibility to select potentially less costly verification methods.

The verification provisions in the draft Guideline (section 9 of the Technical Background Document) are indicative of the foregoing considerations.

5. *Energy Efficiency*

The working group agreed that consideration of energy efficiency should be incorporated into the emission limits. In an effort to address this issue, the alternative forms of stack emission limits, described previously (page 27), were evaluated according to the following criteria:

- effectiveness;
- comprehensiveness;
- verification;
- simplicity;
- applicability.

It was determined that using credits proportional to efficiency improvements was the best option for incorporating energy efficiency into the Guideline. The energy efficiency provisions of the Guideline (section 9 of the Technical Background Document) are consistent with this decision.

Recommendations

The evaluation, described previously (section 7 of the Technical Background Document), of possible emission reduction approaches for new and existing boilers and heaters has resulted in the recommendation of the following "package" of approaches:

1. *NO_x Emission Guideline for New and Modified Large Boilers and Heaters*

2. *Voluntary NO_x Emission Reduction Program*
   Larger existing sources should undertake a program of emission reduction targets applied to the total annual emissions from all sources within a facility. This program would begin with a voluntary effort, after which NO_x emission reductions would be enforced only where necessary. A range of emission reduction program alternatives, including emission trading, should be investigated.

3. *Development of Design Standards Using a Standards Council of Canada Organization*
   To deal efficiently with large numbers of small new boilers and heaters, design standards for minimizing the NO_x emissions of off-the-shelf boilers and heaters should be developed by boiler and heater manufacturers and the appropriate national standards organizations.

4. *Voluntary Boiler and Heater Inspection and Maintenance Program*
   For all large and small existing boilers and heaters, an inspection and maintenance program should be developed by boiler and heater manufacturers, service companies, owners/ operators and fuel supply utilities to optimize performance and minimize fuel consumption.

The recommendations related to item 1 of the package are encompassed in the draft Guideline. The Guideline is not duplicated here but is normally found attached to this executive summary or can be found in section 9 of the Technical Background Document. Further development of items 2, 3 and 4 is recommended, depending on provincial/regional needs but is deferred to other initiatives. However, it was agreed that items 2, 3 and 4 should be included in the preface to the Guideline to emphasize that they represent more practical, effective and economical means of controlling emissions from those boilers and heaters not covered in the Guideline and that they, together with item 1, should be used as a "package."