Guideline A-5

Atmospheric Emissions from Stationary Combustion Turbines

Current Revision Date:

July 2020

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1. Introduction

The purpose of Guideline A-5: Atmospheric Emissions from Stationary Combustion Turbines is to establish the minimum expectations necessary to control air emissions from stationary combustion turbines (SCT) in Ontario. The primary objective is to control emissions of nitrogen oxides (NOx) which is a key ground level ozone precursor.

The main section of this Guideline supersedes the original version published in 1994 for New[1] and Modified SCTs fuelled with Gaseous or Liquid fuels, such as natural gas, renewable natural gas (RNG), biogas, landfill gas, hydrogen, diesel, biodiesel, biodiesel blends, distillate fuel oil and pyrolysis bio-oil. Exemptions from this Guideline for New and Modified SCTs are described in Section 4 (Applicability of the Guideline). The main section of this Guideline does not apply to Existing SCTs that are unmodified or have been subject to a physical or operational change which is intended to: 1) increase the thermal efficiency without changing the emission rate of an air pollutant, or 2) decrease the emission rate of NOx (i.e., grams per second at the maximum power output capacity). In these cases, the guidance in Appendix A of this Guideline, which is based on the original 1994 version of the Guideline, is expected to be applied. This approach is meant to encourage upgrades in thermal efficiency and technology modernization of Existing SCTs that are intended to increase efficiency or reduce emissions but without expecting the more stringent emission limits of New SCTs to be met.

For any SCT, only one guidance format, either in the main section or Appendix A, is to be applied since the definitions of terms and calculation procedures used to determine the concentration-based in-stack limits for NOx are different between the two guidance formats. This is applicable to the use of definitions set out in Section 2 (Definitions) which are only applicable for the content contained in the main section of this Guideline and should not be confused with the definitions set out in Section A2 of Appendix A which are only applicable for the guidance contained in Appendix A.

The main section of this Guideline is primarily based on the “Guidelines for the Reduction of Nitrogen Oxide Emissions from Natural Gas–fuelled Stationary Combustion Turbines” published by Environment and Climate Change Canada in 2017[2].

The intended audience for this Guideline includes persons:

- engaging in an activity mentioned in Section 9 of the Environmental Protection Act, R.S.O. 1990 (the “EPA”) for which a permission such as an environmental compliance approval (ECA) is required (i.e., use, operate, construct, alter, extend or replace with respect to a stationary combustion turbine),

[1] Capitalized terms “New”, “Modified” and “Existing” combustion turbines in the main section of this Guideline are defined in Section 2 and are capitalized throughout the Guideline for clarity (excluding Appendix A).
[2] https://www.canada.ca/content/dam/eccc/documents/pdf/cepa/CEPA-Guidelines-CombustionTurbines-2-en.pdf

- operating an SCT which may be the subject of an Order under the EPA with respect to air emissions,
- engaging in an activity mentioned in Section 47.3 of the EPA for which a permission such as a renewable energy approval (REA) is required (i.e., construction, installation, use, operation, changing or retiring of a renewable energy generation facility with respect to an SCT that generates electricity using a renewable fuel source), and
- manufacturing, distributing or providing engineering or consulting services with respect to an SCT.

During the review of an application for a permission and when considering issuing an Order, the Director or other Ministry official such as a Provincial Officer considers the requirements set out in relevant regulations as well as all applicable Ministry guidelines and policies. To the extent that this document sets out that something is “expected” or “should” be done or sets out a “limit”, it does so only to identify minimum expectations, the application of which remain subject to the discretion of the Director or Provincial Officer. The expectations set out in this Guideline are compulsory to the extent that they are contained in the conditions of a permission such as an ECA or REA or other legally binding instrument, such as a Director’s Order. The Ministry may also consider this Guideline for a person engaging in the installation, use, operation, replacement or modification of an SCT where that activity is a prescribed activity for the purposes of section 20.21 (1) of the EPA under Part II.2 registrations but where the person has been issued a Director’s Order pursuant to Section 20.18 of the EPA and thereby remains under the authority of a permission and is not permitted to register under the Environmental Activity Sector Registry.

While every effort has been made to ensure the accuracy of the information contained in this Guideline, it should not be construed as legal advice. In the event of a conflict with requirements of the EPA or a regulation made under the EPA, the requirements provided for in the legislation and applicable regulations shall be relied upon to determine the appropriate approach.

2. Definitions

The following definitions are provided for use within this Guideline (excluding Appendix A):

"ASTM D6522-20" means the standard ASTM D6522-20, published by ASTM International in 2020 and is entitled *Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers*[3].

"Auxiliary burner" means a combustion device equipped to burn gaseous fuel to reheat the stationary combustion turbine exhaust gases.

"Biogas" has the same meaning as in Ontario Regulation 160/99 made under the *Electricity Act, 1998*.

"Cogeneration" means the integrated operation of one or more stationary combustion turbines that produces mechanical or electrical power and associated devices that recover any heat from the stationary combustion turbine exhaust gases to supply heat (e.g., steam or hot water) for useful purposes other than electricity generation (e.g., to a heating system or an industrial process). For clarity, cogeneration is also commonly referred to as combined heat and power (CHP) and may be configured as part of a simple cycle or combined cycle combustion turbine system.

"Combined cycle" means the integrated operation of one or more stationary combustion turbines, Rankine cycle turbines and auxiliary burners (if applicable) for the co-production of electricity using the same source of thermal energy.

"Combustion turbine" has the same meaning as in Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions) made under the *Environmental Protection Act*. For clarity, this also means stationary combustion turbine (SCT).

"Combustion turbine system" means, where applicable, the stationary combustion turbine(s), Rankine cycle turbine(s), auxiliary burner(s), fuel handling equipment, air pollution controls, flue gas handling equipment, and heat exchangers that are all designed to be operated as an integrated system. It excludes any downstream equipment that receives or uses the mechanical drive, electricity or heat extracted from the combustion turbine system.

"Commissioning date" means the first day on which a stationary combustion turbine begins to produce electricity or mechanical drive power.

"Commissioning period" means the 90-day period following the commissioning date.

[3] https://www.astm.org/Standards/D6522.htm

"CEMS" means Continuous Emissions Monitoring System that is equipment for the sampling, conditioning and analyzing of air emissions from a point source and recording of the data related to those emissions.

"Director" means a Director appointed under section 5 of the EPA for the purpose of a section authorizing the issuance of an Order or permission.

"Emergency combustion turbine" means a stationary combustion turbine that operates only in emergency situations for 100 hours or less within a calendar year, including to produce power for critical networks or equipment during electrical power interruptions, to pump water in the case of fire or flood, or for equipment or facility re-start. For clarity, this is not to be confused with a standby power generating device, which is typically a reciprocating engine.

"ECA" means Environment Compliance Approval and has the same meaning as in the *Environmental Protection Act*.

"EPA" means the Environmental Protection Act, R.S.O. 1990 as amended from time to time.

"EPL" means the expected performance level of a combustion turbine system with regards to thermal efficiency; this value is expected to be met when the combustion turbine system is either newly installed or after a major overhaul and cleaning.

"Existing combustion turbine" means a combustion turbine for which the Ministry received an original application for permission before [date to align with filing of amendments to Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions) made under the *Environmental Protection Act* if approved and filed with the Registrar of Regulations for Ontario] and includes those that subsequently seek an amendment to the permission granted as a result of the original application that have been subject to a physical or operational change which is intended to decrease the emission rate of nitrogen oxides (i.e., grams per second at the maximum power output capacity). For clarity, this definition applies to a combustion turbine that has been subject to routine maintenance (e.g., replacement of turbine blades) or a physical or operational change that is intended to increase the thermal efficiency without increasing the emissions of nitrogen oxides (e.g., by recovering more heat from the exhaust gases).

"Gaseous fuel" means a fuel that is gaseous (such as natural gas, renewable natural gas, hydrogen, biogas and landfill gas) at a temperature of 15 degrees Celsius and an absolute pressure of 101.3 kiloPascals. For clarity, this definition does not apply to gaseous fuels that are derived from the gasification of solid fuels such as biomass and that have not been upgraded to renewable natural gas.

"GPL" means the guaranteed performance level of a combustion turbine system with regards to thermal efficiency; this value is always expected to be met regardless of the age or condition of the combustion turbine system.

"HI" means the gross heat input provided by the fuel to a combustion turbine system reported on a higher heating value basis in gigajoules per hour (may also be expressed as kilowatts or megawatts). For clarity, the HI should be reported for the stationary combustion turbine separately from an auxiliary burner (if applicable) when reporting the total HI for the combustion turbine system.

"HHV" means the higher heating value of the fuel, which is the total amount of heat released during combustion including the latent heat content of the water vapour component of the flue gas.

"HO" means the net heat output produced (i.e., recovered for useful purposes other than electricity generation) by the combustion turbine system (if the combustion turbine system is configured for cogeneration) reported in gigajoules per hour (may also be expressed as kilowatts or megawatts).

"ISO 14687:2019" means the International Standard ISO 14687:2019 published by the International Organization for Standardization (ISO) in 2019 and entitled *Hydrogen fuel quality – Product specification*.

"ISO/TR 15403-2:2006" means the Technical Report ISO/TR 15403-2:2006 published by the International Organization for Standardization (ISO) in 2006 and entitled *Natural gas — Natural gas for use as a compressed fuel for vehicles - Part 2: Specification of the quality.*

"Licensed engineering practitioner" has the same meaning as in Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions) made under the *Environmental Protection Act*.

"Liquid fuel" means a fuel which, as received, at atmospheric conditions is a liquid (such as diesel, biodiesel, biodiesel blends, distillate fuel oil and pyrolysis bio-oil).

"Maximum power output capacity" means the reported maximum continuous rating (in megawatts) of a stationary combustion turbine at the International Organization for Standardization (ISO) 3977-2 environmental design point conditions of ambient air: 15 degrees Celsius, 60 percent relative humidity and 101.3 kiloPascals barometric pressure. For clarity, this means electrical power or mechanical power and can also be referred to as "power rating" or "nameplate capacity" and only applies to a stationary combustion turbine, not a combustion turbine system (see definition for "PO"). The reported value is expected to be corrected for any increase or decrease resulting from the use of in-situ methods to control nitrogen oxides such as steam injection or lean burn fuel firing.

"Modified combustion turbine" means a previously Existing combustion turbine which has been subjected to a physical or operational change which results or may result in:

- an increase in emissions (in grams per second at maximum power output capacity) of nitrogen oxides; or,
- the emission of an air pollutant which was not previously emitted and is not caused by the addition of nitrogen oxides emission reduction measures.

For clarity, this definition does not apply to an Existing combustion turbine that has been subject to routine maintenance (e.g., replacement of turbine blades) or a physical or operational change that is intended to increase the thermal efficiency without increasing the emissions of nitrogen oxides (e.g., recovering more heat from the exhaust gases).

"Natural gas" means a gaseous fuel that is at least 90 percent methane by volume and has an energy content of at least 35 megajoules per cubic metre. The total sulphur content of natural gas is expected to be less than 120 milligrams per cubic metre as per ISO/TR 15403-2:2006.

"New combustion turbine" means a combustion turbine for which the Ministry received an original application for permission on or after [date to align with filing of amendments to Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions) made under the *Environmental Protection Act* if approved and filed with the Registrar of Regulations for Ontario].

"Non-peaking combustion turbine" means a combustion turbine that is not used as a Peaking combustion turbine.

"Operator" means a person who has the charge, management or control of a combustion turbine system who may or may not be the owner.

"NOx" means nitrogen oxides as prescribed in Ontario Regulation 419/05.

"Part-load operation" means the operation of the stationary combustion turbine below 70 percent of its maximum power output capacity.

"Peaking combustion turbine" means a stationary combustion turbine that is operated for 1,500 hours or less within a calendar year.

"PO" means the gross mechanical power output and, as the case may be, the gross electrical power output of the combustion turbine system - where the combined values from these devices should provide the total power output (mechanical and/or electrical) of the combustion turbine system reported in gigajoules per hour (may also be expressed as kilowatts or megawatts). This is an equivalent term to "nominal power output" for a combustion turbine system (see definition for "Maximum power output capacity"). For clarity, the PO includes the electrical power output of a Rankine cycle turbine (where applicable if the combustion turbine system is configured for combined cycle) and is to be corrected for any increase or decrease resulting from the use of in-situ methods to control NOx such as steam injection or lean burn fuel firing.

“POSC” means a power-only, simple cycle stationary combustion turbine that does not harness the stationary combustion turbine exhaust heat for any purpose.

“Pre-test plan” means a summary of the sampling protocols and testing methods, as approved by the Ministry, to be employed by the operator during source testing of the combustion turbine system.

“RATA” means relative accuracy test audit, which is the on-site certification of a continuous emission monitoring system (CEMS) to measure emissions accurately by comparing measured values concurrently with an independently operated CEMS.

“Rankine cycle turbine” means a turbine that uses heat from the stationary combustion turbine exhaust gases and auxiliary burner (if applicable) to generate electrical power as part of a combined cycle combustion turbine system. In general, the Rankine cycle turbine can use either steam or organic, high molecular mass fluid as the heat transfer fluid and are referred to as steam turbines and Organic Rankine Cycle turbines, respectively.

“Reference conditions” means flue gas measurements corrected to 15 degrees Celsius, dry basis (no moisture) and 101.3 kiloPascals barometric pressure.

“RNG” means renewable natural gas, which is a gaseous fuel that has been derived from biogas or biomass and that meets the expectations for natural gas as set out in this Section.

“SCT” means stationary combustion turbine and has the same meaning as “combustion turbine”.

“Shut-down” has the same meaning as in subsection 11(2) of Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions) made under the *Environmental Protection Act*.

“Simple cycle” means a combustion turbine system that does not include the operation of a Rankine cycle turbine.

“Start-up” has the same meaning as in subsection 11(2) of Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions) made under the *Environmental Protection Act*.

“Thermal efficiency” means the ratio of delivered useful energy output (e.g., PO and HO) to the energy input (HI), expressed as a percentage on a higher heating value basis. Refer to Equation 10 in Section 8.2 of this Guideline for expression as a formula.

3. Abbreviations

LEP	licenced engineering practitioner
SCT	stationary combustion turbine
RNG	renewable natural gas
MW	megawatt (equal to 3.6 GJ/hr)
g	gram
GJ	gigajoule (equal to 0.278 MWhr)
GJ/hr	gigajoules per hour (equal to 0.278 MW)
ppmv @15% O_2	parts per million by volume corrected to 15 percent oxygen at reference conditions
NOx	nitrogen oxides (expressed as total equivalent of nitrogen dioxide)
CO	carbon monoxide
SO_2	sulphur dioxide
kPa	kiloPascal
°C	degree Celsius
EPL	expected performance level
GPL	guaranteed performance level

4. Applicability of the Guideline

This Guideline (except for Appendix A) applies to all New and Modified SCTs that use Gaseous or Liquid fuels, except for the following exemptions:

- emergency combustion turbines,
- combustion turbines used solely for purposes of research and development and field demonstration (e.g., a pilot plant with a limited operational timeframe), and
- combustion turbines under repair, those being tested during their commissioning period or during verification of repairs.

There are several key design parameters that are needed to describe the applicability of a combustion turbine system, including:

- maximum power output capacity,
- fuel type(s) and specification(s),
- thermal efficiency (including descriptions of HI, PO and HO),
- peaking or non-peaking,
- mechanical drive or electrical power,
- power-only, simple cycle (POSC) SCT or SCT with heat recovery included,
    - if heat recovery is included, describe if the heat is used for additional electricity generation (e.g., combined cycle with Rankine cycle turbine), purposes other than electricity production (e.g., simple cycle with cogeneration) or both (e.g., combined cycle with Rankine cycle turbine and cogeneration)
- auxiliary burner(s), and
- orientation of exhaust gas ductwork, describe if one or more than one SCT is connected to a common stack.

A definition for natural gas is provided in Section 2 (Definitions) to recognize that in Ontario the conventional pipeline natural gas supply is now a mixture of methane from fossil fuel sources, RNG derived from biogas and biomass as well as hydrogen from “Power-to-gas” systems being directly injected. For clarity, any natural gas that is delivered to a facility through a pipeline: 1) by a gas distributor or gas transmitter whose rates are set under section 36 of the *Ontario Energy Board Act, 1998*, or 2) that is regulated under Part 3 of the *Canadian Energy Regulator Act,* or 3) by Utilities Kingston or Kitchener Utilities is considered to have met the intent of the natural gas definition. If natural gas is not delivered to a facility through such a pipeline as described above, then it is expected that the operator will be able to demonstrate that the natural gas used in an SCT meets the expectations of the parameters set out in the definition.

The expectations of this Guideline primarily apply to biogas / landfill gas that has been processed to have impurities removed comparable to natural gas as defined in Section 2 (Definitions) but has not had the carbon dioxide removed and therefore is not considered to be RNG. It is expected that the methane content will be less than 90 percent, the energy content less than 35 megajoules per cubic metre and the total sulphur content less than 120 milligrams per cubic metre. Should the sulphur content of the Gaseous fuel exceed 120 milligrams per cubic metre then source testing will be expected for sulphur dioxide (SO_2).

The quality of RNG will only be recognized as equivalent to natural gas where the RNG meets the expectations for natural gas as defined in Section 2 (Definitions).

Where hydrogen gas is to be used as a fuel (whether blended with natural gas or not), it is expected that the hydrogen gas will meet the requirements set out for at least one of the types and grades of hydrogen fuel as prescribed in ISO 14687:2019. Should the sulphur content of the hydrogen gas exceed 120 milligrams per cubic metre then source testing will be expected for SO_2.

The applicable fuel sulphur limit for diesel, biodiesel and biodiesel blends is 0.0015 percent by mass. The applicable fuel sulphur limit for distillate fuel oils and pyrolysis biofuels is 0.05 percent by mass. For pyrolysis biofuels, only the ASTM D 7544-12 standard is to be used (current edition to be referenced at the time of application for permission). For the purposes of this Guideline, it is considered best practice to use fuel standards published by ASTM International or the Canadian General Standards Board (CGSB) for Liquid fuels as these industry standards are widely recognized and used throughout Ontario. Should the total sulphur content of a Liquid fuel exceed the limits described above, then source testing will be expected for SO_2.

In summary, if the concentration of total sulphur in the Gaseous fuel does not meet the expectations for natural gas or where the total sulphur content of Liquid fuels does not meet the limits described above then source testing will be expected for SO_2.

5. Emission Limits

The methods available for determining compliance with the expected emission limits are the **output-based method** and the **concentration-based method** as described below:

- According to the **output-based method**, emission limits are expressed as emission intensity (e.g., mass of emission per unit output of shaft or electrical energy with an allowance for recovered heat, if applicable for cogeneration). The emission limits take into consideration the quantity of energy produced by the combustion turbine system (including heat if applicable for cogeneration), calculated in gigajoules (GJ) as well as the emissions calculated in grams (g).
- According to the **concentration-based method**, emission limits are expressed as a concentration in parts per million by volume (ppmv) in the flue gas at reference conditions. This method is not typically used for NOx emission limit compliance assessment where the combustion turbine system is configured for combined cycle, cogeneration or both. However, for SCTs with a maximum power output capacity of less than 25 MW that are configured for combined cycle, cogeneration or both and that use natural gas and/or hydrogen as fuels, concentration-based NOx limits are provided.

The emission limits are expected to apply to the combustion turbine system, inclusive of auxiliary burners, at the point of discharge to the environment, downstream of any air pollution control equipment where each SCT is exhausted either through its own stack or a common stack for multiple SCTs. Where two (2) or more SCTs of different PO are combined in a combustion turbine system, the most stringent in-stack limit of any SCT in the system is expected to apply to the combustion turbine system.

The output-based NOx limits should generally be used and validated with a thermal efficiency measurement. However, for SCTs with a maximum power output capacity of less than 25 MW that use only natural gas and/or hydrogen as a fuel, the use of concentration-based NOx limits can be applied directly.

The emission limits are expected to apply at all times when applicable combustion turbine systems are operating, except during start-up periods, shut-down periods or when the ambient temperature at the point of air intake is less than -18°C.

5.1 Emission Limits for Nitrogen Oxides for Gaseous Fuels

The NOx emission limits for Gaseous fuels are a function of the combustion turbine system application and SCT maximum power output capacity (expressed in MW) as described below:

- Table 1 provides the output-based method emission limits that are applicable in all scenarios but requires interpretation to convert to a concentration-based limit and a thermal efficiency measurement to confirm the limit. The concentration-based limits listed in Tables 2 and 3 are derived from these limits for specific applications.
- Table 2 provides the concentration-based method emission limits for POSC SCTs.
- Table 3 provides concentration-based emission limits for SCTs with a maximum power output capacity of less than 25 MW that use only natural gas and/or hydrogen as fuels. These limits are the same as Table 2 where the thermal efficiency is less than 60 percent.

Table 1: Emission Limits for NOx – output-based method for Gaseous fuels

Application of Combustion Turbine System	SCT Maximum Power Output Capacity (MW)	NOx Emission Limits (g/GJ energy output)
Non-peaking – mechanical drive	< 4	500
Non-peaking – electricity generation	< 4	290
Peaking (1)	< 4	not applicable (2)
Non-peaking and peaking (1)	≥ 4 and ≤ 70	140
Non-peaking (1)	> 70	85
Peaking (1)	> 70	140

Notes:

(1) Combustion turbine system used for either mechanical drive or electricity generation

(2) Although there is not an emission limit for this application, facilities using these devices are subject to the point of impingement limits in Local Air Quality Regulation O. Reg. 419/05

Table 2: Emission Limits for NOx – concentration-based method for Gaseous fuels for POSC SCT

Application of Combustion Turbine System	SCT Maximum Power Output Capacity (MW)	NOx Emission Limits (ppmv @ 15% O_2)
Non-peaking – mechanical drive	< 4	75
Non-peaking – electricity generation	< 4	42
Peaking (1)	< 4	not applicable (2)
Non-peaking and peaking (1)	≥ 4 and ≤ 70	25
Non-peaking (1)	> 70	15
Peaking (1)	> 70	25

Notes:

(1) Combustion turbine system used for either mechanical drive or electricity generation
(2) Although there is not an emission limit for this application, facilities using these devices are subject to the point of impingement limits in Local Air Quality Regulation O. Reg. 419/05

Table 3: Emission Limits for NOx – concentration-based method for SCT that use natural gas and/or hydrogen as fuels with a maximum power output capacity of less than 25 MW

Application of Combustion Turbine System	SCT Maximum Power Output Capacity (MW)	Thermal Efficiency (%)	NOx Emission Limits (ppmv @ 15% O_2)
Non-peaking – mechanical drive	< 4	< 60	75
Non-peaking – mechanical drive	< 4	≥ 60	100
Non-peaking – electricity generation	< 4	< 60	42
Non-peaking – electricity generation	< 4	≥ 60	60
Peaking (1)	< 4	not applicable	not applicable (2)

Application of Combustion Turbine System	SCT Maximum Power Output Capacity (MW)	Thermal Efficiency (%)	NOx Emission Limits (ppmv @ 15% O_2)
Non-peaking and peaking (1)	≥ 4 and < 25	< 60	25
Non-peaking and peaking (1)	≥ 4 and < 25	≥ 60	34

Notes:

(1) Combustion turbine system used for either mechanical drive or electricity generation
(2) Although there is not an emission limit for this application, facilities using these devices are subject to the point of impingement limits in Local Air Quality Regulation O. Reg. 419/05

5.2 Emission Limits for Nitrogen Oxides for Liquid Fuels

The NOx emission limits for Liquid fuels are a function of the combustion turbine system application and SCT maximum power output capacity (expressed in MW) and are provided in Tables 4 and 5 below for the output-based method and concentration-based method, respectively for Liquid fuels.

Table 4: Emission Limits for NOx – output-based method for Liquid fuels

Application of Combustion Turbine System	SCT Maximum Power Output Capacity (MW)	NOx Emission Limits (g/GJ energy output)
Non-peaking – mechanical drive	< 4	750
Non-peaking – electricity generation	< 4	435
Peaking (1)	< 4	not applicable (2)
Non-peaking and peaking (1)	≥ 4 and ≤ 70	210
Non-peaking (1)	> 70	128
Peaking (1)	> 70	210

Notes:

(1) Combustion turbine system used for either mechanical drive or electricity generation

(2) Although there is not an emission limit for this application, facilities using these devices are subject to the point of impingement limits in Local Air Quality Regulation O. Reg. 419/05

Table 5: Emission Limits for NOx – concentration-based method for Liquid fuels for POSC SCT

Application of Combustion Turbine System	SCT Maximum Power Output Capacity (MW)	NOx Emission Limits (ppmv @ 15% O_2)
Non-peaking – mechanical drive	< 4	113
Non-peaking – electricity generation	< 4	63
Peaking (1)	< 4	not applicable (2)
Non-peaking and peaking (1)	$\geq$ 4 and $\leq$ 70	38
Non-peaking (1)	> 70	23
Peaking (1)	> 70	38

Notes:

(1) Combustion turbine system used for either mechanical drive or electricity generation
(2) Although there is not an emission limit for this application, facilities using these devices are subject to the point of impingement limits in Local Air Quality Regulation O. Reg. 419/05

5.3 Emission Limit for Carbon Monoxide

The carbon monoxide (CO) emission limit for combustion turbine systems of all sizes and fuel types is 50 ppmv, corrected to 15% O_2 at reference conditions.

6. Calculation of Emission Levels

The methodology that is expected to be used to calculate emission rates in order to determine emission limits is described in this Section. Sample calculations results are provided in Appendix B.

6.1 Quantification of Energy Production

The operator of a combustion turbine system is expected to install, operate and maintain continuous monitoring devices to measure the quantities (where applicable) of heat input (HI), heat output (HO) and power output (PO) and record the integrated averages on an hourly basis with a known date and time reference. The use of advanced electronic instruments and devices together with a computer-controlled data recording and processing system is expected to achieve the highest level of accuracy for measured data and resulting recorded values according to the known date and time reference. For example, the devices could measure values such as natural gas fuel input (cubic metres per second – m^3/s), natural gas HHV (megajoules per cubic metre – MJ/m^3), electrical PO (MW), steam flow (kilograms per second – kg/s), steam pressure (kiloPascals - kPa), steam temperature (degrees Celsius - °C), ambient air temperature (°C), barometric pressure (kPa) and other parameters as necessary to quantify the HI, HO and PO.

In configurations with multiple SCTs and/or multiple Rankine cycle turbines, the PO of each Rankine cycle turbine(s) should be proportionately allocated to the PO of each SCT, according to its contribution to the input energy of each Rankine cycle turbine.

Likewise, in configurations with multiple SCTs and/or multiple Rankine cycle turbines, the HO of each Rankine cycle turbine should be proportionally allocated to each SCT according to its contribution to the input energy of each Rankine cycle turbine.

6.2 NOx Emissions - Output-Based Method

The NOx emission rate can be calculated using the output-based method using either Equation 1 or Equation 2 as described below.

$$\mathbf{E_{NOx} = C \times 1.88 \times 10^{-3} \times Q_s} \qquad \textbf{Equation 1}$$

where: E_{NOx} is the NOx emission rate (g NOx/hr)

C is the measured NOx concentration in the flue gas (ppmv, dry basis)

1.88×10^{-3} is the conversion factor for NOx, from ppmv to g/m^3

Q_s is the stack gas flow rate (m^3/hr, reference conditions)

E_{NOx} = C x F_d x HI x 1.88 x 10^{-3} x 20.9 / (20.9 - %O_2) **Equation 2**

where: E_{NOx} is the NOx emission rate (g NOx/hr)

C is the measured NOx concentration in the flue gas (ppmv, dry basis)

F_d is the fuel factor (F-factor) of 240 DSm³/GJ for natural gas (other F_d must be used for fuels other than natural gas, to be calculated according to Federal reference method[4])

1.88 x 10^{-3} is the conversion factor for NOx, from ppmv to g/m³

HI is the gross heat input provided by the fuel to the combustion turbine system (GJ/hr)

%O_2 is the oxygen concentration in the flue gas (volume percentage, dry basis)

6.3 NOx Emissions - Concentration-Based Method

The NOx emission concentration can be calculated using the concentration-based method using Equation 3 as described below.

C_{15} = C x (20.9 - 15) / (20.9 - %O_2) **Equation 3**

where: C_{15} is the concentration of NOx in the flue gas corrected to 15% O_2 (ppmv, dry basis)

C is the measured NOx concentration in the flue gas (ppmv, dry basis)

%O_2 is the oxygen concentration in the flue gas (volume percentage, dry basis)

6.4 CO Emissions - Concentration-Based Method

The CO emission concentration can be calculated using the concentration-based method using Equation 4 as described below.

CO_{15} = CO x (20.9 - 15) / (20.9 - %O_2) **Equation 4**

where: CO_{15} is the concentration of CO in the flue gas corrected to 15% O_2 (ppmv, dry basis)

CO is the measured CO concentration in the flue gas (ppmv, dry basis)

[4] http://ec.gc.ca/doc/cc/COM1343/a_a-eng.htm#a_a_3

$\%O_2$ is the oxygen concentration in the flue gas (volume percentage, dry basis)

7. Verification of Emission Limits

The methods that are expected to be used to verify compliance with emission limits presented in Section 5, using the information developed in Section 6, are described in this Section. There are multiple methods but applicability is SCT specific as identified in Equations 5 through 9. Sample calculations results are provided in Appendix B.

7.1 NOx Emissions - Output-Based Method for Power Generation

For combustion turbine systems configured for mechanical or electrical power generation (e.g., POSC or combined cycle), the verification of compliance can be determined using the output-based method with Equation 5 as described below.

$$\mathbf{E_{NOx} \leq PO \times A} \qquad \textbf{Equation 5}$$

where: E_{NOx} is the NOx emission rate (g NOx/hr) calculated using either Equation 1 or Equation 2

PO is the gross power output (GJ/hr)

A is the applicable emission limit in either Table 1 or Table 4, depending on fuel type (g/GJ)

7.2 NOx Emissions - Output-Based Method for Cogeneration

For combustion turbine systems configured for cogeneration (e.g., simple cycle or combined cycle), the verification of compliance can be determined using the output-based method with Equation 6 for Gaseous fuels or Equation 7 for Liquid fuels, respectively as described below.

$$\mathbf{E_{NOx} \leq (PO \times A) + (HO \times 40)} \qquad \textbf{Equation 6}$$

where: E_{NOx} is the NOx emission rate (g NOx/hr) calculated using either Equation 1 or Equation 2

PO is the gross power output (GJ/hr)

A is the applicable emission limit in Table 1 (g/GJ)

HO is the net heat output (GJ/hr)

40 is the cogeneration coefficient for Gaseous fuels (g/GJ)

$E_{NOx} \leq (PO \times A) + (HO \times 60)$ **Equation 7**

where: E_{NOx} is the NOx emission rate (g NOx/hr) calculated using either Equation 1 or Equation 2

PO is the gross power output (GJ/hr)

A is the applicable emission limit in Table 4 (g/GJ)

HO is the net heat output (GJ/hr)

60 is the cogeneration coefficient for Liquid fuels (g/GJ)

7.3 NOx Emissions - Concentration-Based Method

For combustion turbine systems configured for POSC with applicable limits set out in Table 2 for Gaseous fuels or Table 5 for Liquid fuels or otherwise those with applicable limits set out in Table 3 for natural gas and/or hydrogen fuels, the verification of compliance can be determined using Equation 8 as described below.

$C_{15} \leq A$ **Equation 8**

where: C_{15} is the concentration of NOx in the flue gas corrected to 15% O_2 (ppmv, dry basis) calculated using Equation 3

A is the applicable emission limit in either Table 2, 3 or 5 (ppmv)

7.4 CO Emissions - Concentration-Based Method

The verification of compliance with the CO emission limit can be determined using the concentration-based method with Equation 9 as described below.

$CO_{15} \leq 50$ **Equation 9**

where: CO_{15} is the concentration of CO in the flue gas corrected to 15% O_2 (ppmv, dry basis) calculated using Equation 4

50 is the emission limit (ppmv, dry basis)

8. Emission Testing and Monitoring

The emission testing and monitoring methods to be used for assessing either combustion turbine system compliance or performance are described in this Section. The design performance characteristics of an SCT depend upon the type and model of SCT, the location at which it is installed, the ambient conditions under which it operates, the fuel it uses and the NOx reduction methods. For example, an SCT delivers less PO at higher elevations, whereas the PO and thermal efficiency both decrease at higher ambient temperatures.

When an SCT is new, no physical degradation of the mechanical components has yet occurred, such as: fouling of the compressor blades due to air-borne dust; fouling or degradation of the combustion system or turbine blades due to contact with hot combustion gases; fouling of the inlet air filters; or change in exhaust backpressure due to fouling of the exhaust system or heat exchanger. The SCT's expected performance level (EPL) should be achieved when new whereas the guaranteed performance level (GPL) will be lower and account for decreased performance due to normal use over time.

It is expected that the GPL of an SCT will continue to be met despite any wear and tear from normal use, whereas the EPL may only be achievable when the SCT is new or potentially after a major overhaul and cleaning. As a general best practice, the GPL should not be less than 5 percent below the EPL.

8.1 Operating Conditions and Measurement Methods

8.1.1 Operating Conditions

For emission testing and monitoring of a combustion turbine system under steady state operating conditions, the data collected should only be considered valid under the following conditions:

- the load level should be as close to 100% of the maximum power output capacity as possible and is expected to be above 70%,
  - if the load level is below 70%, the emissions results should be considered interim (for information purposes only) and a follow-up emission test should be scheduled when the unit can achieve above 70% load level of the maximum power output capacity
  - periods of start-up, shut-down and malfunction are not expected to be included in any testing results. For clarity, the operator of an SCT may choose to conduct emission testing activities during these periods for other purposes which are beyond the expectations of this Guideline
- the ambient air temperature is greater than or equal to -18°C,
- the emission samples are expected to be taken from a sampling port that meets the specifications set out in the Ontario Source Testing Code[5],
- when more than one SCT is venting through a common stack, the emission samples taken from that stack should take place with one SCT operating at a time and the other SCT's exhaust ductwork isolated from the common stack so the SCT's flue gas is not diluted

[5] https://www.ontario.ca/document/ontario-source-testing-code-0

- if more than one SCT shares air emission control equipment, one emission test can be considered for all SCTs when taken downstream of the air emission control equipment.

8.1.2 Measurement Methods

Measurement devices used for collecting data, including combustion turbine system operating data and emission data, should be calibrated either at the frequency recommended by the manufacturer, as specified in the test methods for the devices or at least once every two calendar years, whichever is the most frequent. Measurement devices should be accurate within ± 5 percent.

8.2 Installation Test

Before the end of the commissioning period of any combustion turbine system with a maximum power output capacity of less than 25 MW using only natural gas and/or hydrogen as a fuel, an installation test is expected to be performed to determine if the combustion turbine system is operating below the appropriate emission concentration limits of the permission. For clarity, the installation test is an assessment of equipment performance and is not to be considered a determination of compliance (i.e., not equivalent to source testing as described in Section 8.4 of this Guideline).

The combustion turbine system should be operated for a minimum of one (1) hour according to the operating conditions set out in Section 8.1.1 of this Guideline and emissions of NOx, CO and O_2 measured according to the methodology described in ASTM D6522-20 and with a portable combustion gas analyzer that meets the requirements of ASTM D6522-20. Emission levels should be compared with the appropriate emission concentration limits of the permission and documented.

If the combustion turbine system exhaust ventilation ductwork is combined for two or more SCTs, then the installation test is expected to be verified by an LEP to ensure that the operating conditions set out in Section 8.1.1 of this Guideline are met. When a report is prepared to document the emission data from an installation test, it is expected to be dated, signed and sealed by an LEP and set out the practitioner’s name and licence number. The information in the report is expected to be accurate as of the date it is signed and sealed. If the SCT discharges to its own dedicated exhaust stack and has a maximum power output capacity of less than 1 MW then this additional oversight by an LEP is not expected although the operating conditions set out in Section 8.1.1 of this Guideline are expected to be met.

The thermal efficiency is expected to be determined on an hourly basis using the continuously monitored energy parameters described in Section 6.1 and calculated as per Equation 10 below:

TE = 100 x (PO + HO) / HI **Equation 10**

where: TE = thermal efficiency (%)

PO = power output (GJ/hr)

HO = heat output (GJ/hr)

HI = heat input (GJ/hr)

Thermal efficiency on-site testing is expected to verify the correct operation of the energy quantification devices set out in Section 6.1 and the operator is expected to follow the recommendations of the technology provider of the combustion turbine system to ensure the GPL is achieved. The thermal efficiency is expected to be verified by an LEP during the installation test. If the SCT discharges to its own dedicated exhaust stack and has a maximum power output capacity of less than 1 MW then this additional oversight by an LEP is not expected.

For combustion turbine systems with a PO of 5 MW or greater, the Ministry considers it a best practice to quantify the thermal efficiency using one of the following standards:

- ISO 2314:2009 entitled “Gas turbines – acceptance tests”, or
- ISO 18888:2017 entitled “Gas turbine combined cycle power plants – Thermal performance tests”.

A report is expected to be prepared to document the emission data performance assessment and thermal efficiency verification from the installation test, whether oversight by an LEP is expected or not. The report is expected to be dated, signed and sealed by an LEP and set out the practitioner’s name and licence number where oversight by an LEP is expected. The information in the report is expected to be accurate as of the date it is signed and sealed.

8.3 Emission Monitoring

For a Non-peaking combustion turbine system with a PO equal to or greater than 25 MW, a Continuous Emissions Monitoring System (CEMS) is expected to be designed, installed, operated and maintained to verify compliance with the appropriate emission concentration limits of the permission. The CEMS is expected to include an oxygen monitor to correct the emission rate to 15% O_2 and a flue gas temperature and pressure monitor to correct the reported emissions to reference conditions.

The CEMS is expected to record the emission data averages on an hourly basis along with a date and time reference. The use of advanced electronic instruments and devices together with a computer-controlled data recording and processing system is expected to achieve the highest level of accuracy for measured data and resulting reported values according to the known date and time reference. The date and time reference for the CEMS data is expected to be synchronized with the date and time reference for the energy quantification data described in Section 6.1.

For combustion turbine systems equipped with CEMS, compliance is expected to be demonstrated if the monitored contaminant emission results, on a 24-hour rolling average calculated on an hourly basis, are less than the appropriate emission concentration limits of the permission. The emission limits are expected to apply at all times when an applicable combustion turbine system is operating except during start-up periods, shut-down periods or when the ambient temperature at the point of air intake is less than -18°C.

Upon receipt of a permission from the Ministry that requires a CEMS for a New combustion turbine, it is expected that the operator will submit a CEMS plan to the Ministry for review and approval prior to procurement and installation of a CEMS as approved by the Ministry[6]. The CEMS plan is expected to include a provision to perform a Relative Accuracy Test Audit (RATA) at least once every two (2) years so that the RATA measurements and accompanying reports can be used to assess air emission levels in lieu of source testing for NOx and CO.

8.4 Source Testing Parameters

The expectations for source testing used to verify compliance with the appropriate emission concentration limits of the permission are a function of the operating conditions described in Section 8.1.1 of this Guideline, the combustion turbine system application and PO (expressed in MW), including the PO from a Rankine cycle turbine if configured as combined cycle and are provided in Table 6 below.

Table 6: Source Testing Parameters

Category Number	Application of Combustion Turbine System (1)	Combustion Turbine System Power Output (MW)	Source Testing Parameters (2)
1	Peaking and non-peaking using natural gas and/or hydrogen only as a fuel	< 25	Not applicable (3)
2	Peaking and non-peaking using fuels other than natural gas and/or hydrogen only	< 25	NOx, CO, SO_2 within 6 months of commissioning period and then every 2 calendar years (4)
3	Peaking	$\geq$ 25	NOx, CO within 6 months of commissioning period and then every 2 calendar years

[6] These expectations may be applied to an Existing or Modified combustion turbine if the Ministry considers it appropriate.

Category Number	Application of Combustion Turbine System (1)	Combustion Turbine System Power Output (MW)	Source Testing Parameters (2)
4	Non-peaking	≥ 25	Not applicable (5)

Notes:

(1) Combustion turbine system used for either mechanical drive or electricity generation
(2) Source testing is expected to be performed in accordance with a Pre-test plan that has been approved by the Ministry for the initial source testing campaign and the Ontario Source Testing Code[7]
(3) Source testing parameters are expected to be applied as per category 2 for any SCT using a fuel other than natural gas and/or hydrogen only, if: 1) an auxiliary burner(s) is included that has a maximum fuel input capacity greater than that of the SCT, 2) if the auxiliary burner(s) uses any fuel other than natural gas or hydrogen only regardless of the maximum fuel input capacity, or 3) if the natural gas and/or hydrogen fuel has a total sulphur concentration of greater than 120 milligrams per cubic metre
(4) Source testing is only expected to be performed for SO_2 where fuel sulphur limits are not met, as described in Section 4 of this Guideline, in an SCT and/or auxiliary burner(s)
(5) Where CEMS is expected for these SCTs, a RATA is expected to be conducted at least once every two years so that source testing would not be expected. If a RATA is not performed at least once every two years, source testing would be expected to be applied as per category 3

For combustion turbine systems that are expected to conduct source testing according to an approved Pre-test plan, compliance is expected to be demonstrated where the average of the three source test runs is less than the appropriate emission concentration limits of the permission.

The thermal efficiency is expected to be determined during each source testing program on an hourly basis using the continuously monitored energy parameters as described in Section 6.1 and calculated as per Equation 10 in Section 8.2. Thermal efficiency on-site testing is expected to verify the correct operation of the energy quantification devices set out in Section 6.1 and the operator is expected to follow the recommendations of the technology provider of the combustion turbine system to ensure the GPL is achieved.

For combustion turbine systems with a PO of 5 MW or greater, the Ministry considers it a best practice to quantify the thermal efficiency using one of the following standards:

- ISO 2314:2009 entitled “Gas turbines – acceptance tests”, or

[7] https://www.ontario.ca/document/ontario-source-testing-code-0

- ISO 18888:2017 entitled “Gas turbine combined cycle power plants – Thermal performance tests”.

8.5 Performance Assessment

It is typical for the performance of a combustion turbine system to decrease over time due to fouling and erosion of the gas flow path and general wear and tear experienced during normal operation. Some of this performance may not be recoverable or remediated by regular preventive maintenance activities such as compressor cleaning, turbine cleaning and filter cleaning. As such, an SCT will no longer deliver the same performance as a newly installed system after normal use, unless it has recently had a major overhaul and cleaning. Therefore, all combustion turbine systems are expected to conduct a performance assessment at least once every 2 years to ensure that the equipment is continuing to operate in a manner which is consistent with the GPL from the technology provider (whether source testing or CEMS is expected or not) and this performance assessment is expected to be done concurrently with source testing or a CEMS RATA test where it is required.

During performance assessment testing, the combustion turbine system should be operated for a minimum of one (1) hour according to the operating conditions set out in Section 8.1.1 of this Guideline with emissions of NOx, CO and O_2 measured with either a CEMS, source test or portable combustion gas analyzer (if source testing or CEMS is not required). Portable combustion gas analyzers should be selected and operated according to the methodology and equipment requirements described in ASTM D6522-20. Emission levels are to be compared with the appropriate emission concentration limits of the permission and documented. Similar to the installation test, any testing activity performed with a portable combustion gas analyzer is considered to be an assessment of equipment performance and is not to be considered a determination of compliance (i.e., only source testing and CEMS are considered to be activities that determine compliance with emission limits).

For combustion turbine systems that do not require source testing or CEMS and where the combustion turbine system exhaust ventilation ductwork is combined for two or more SCTs, then the performance assessment is expected to be verified by an LEP to ensure that the operating conditions set out in Section 8.1.1 of this Guideline are met. A report is expected to be prepared to document the emission data from a performance assessment and it must be dated, signed and sealed by an LEP and set out the practitioner’s name and licence number. The information in the report is expected to be accurate as of the date it is signed and sealed. If the SCT discharges to its own dedicated exhaust stack and has a maximum power output capacity of less than 1 MW then this additional oversight by an LEP is not expected. The operating conditions set out in Section 8.1.1 of this Guideline are expected to be met in any case.

The thermal efficiency is expected to be determined as described in Section 8.2 where source testing is not required and Section 8.4 where source testing is required. Where source testing is not required, the thermal efficiency is expected to be verified by an LEP during the performance assessment as described in Section 8.2 unless the SCT has a maximum power output capacity of less than 1 MW then this additional oversight by an LEP is not expected.

A report is expected to be prepared to document the emission data and thermal efficiency from the performance assessment, whether oversight by an LEP is expected or not. Where source testing is not required, the report is expected to be dated, signed and sealed by an LEP and set out the practitioner’s name and licence number. The information in the report is expected to be accurate as of the date it is signed and sealed.

The expectations described above should be considered the minimum amount of work to ensure continued reliable and efficient operation of the combustion turbine system and should not be used in lieu of any recommendations by the manufacturer to maintain the continued optimal performance of the equipment.

9. Record Keeping Parameters

This Chapter sets out the records that are expected to be kept by the operator of a combustion turbine system. The following information will assist the Director in assessing whether the combustion turbine system meets the expectations set out in this Guideline (where applicable).

9.1 Description of Combustion Turbine System and Facility

This Section sets out the information that is expected to be submitted in an application for a permission with respect to a combustion turbine system and, with respect to a new SCT, documented prior to the installation of a new SCT.

1. SCT manufacturer’s name, model number and series designation
2. Maximum power output capacity of the SCT (report both gross and net values)
3. Facility elevation (metres above sea level)
4. Application of combustion turbine system:
    a. peaking or non-peaking,
    b. mechanical drive or electrical power, and
    c. POSC SCT or SCT with heat recovery included
        - if heat recovery is included, describe if the heat is used for additional electricity generation (e.g., combined cycle with Rankine cycle turbine), purposes other than electricity production (e.g., simple cycle with cogeneration) or both (e.g., combined cycle with Rankine cycle turbine and cogeneration).
5. Fuel type(s) and specification(s) - separately for the SCT and the auxiliary burner(s)
6. HI (report SCT and auxiliary burner separately, in addition to total)

7. PO (report both gross and net values separately for the SCT and Rankine cycle turbine as well as the total for the combustion turbine system)
8. HO (report both gross and net values)
9. Thermal efficiency (report both gross and net values):
   a. expected performance level, and
   b. guaranteed performance level.
10. Abatement methods for control of NOx
11. Expected emission concentrations and emission rates for NOx and CO (corrected to reference conditions)
12. Exhaust stack design configuration:
   a. describe which SCTs are discharging into which exhaust stack,
   b. describe the location of air pollution control equipment used for more than one SCT within an exhaust stack,
   c. describe where the emission sampling port(s) are located within the exhaust stack, and
   d. exhaust gas flowrate and temperature of each exhaust stack.

9.2 Data and Reports

This Section sets out the expectations regarding the data and reports that are expected to be created and kept (as applicable) by this Guideline.

1. Quantification of energy production (HI, PO and HO) as described in Section 6.1:
   a. hourly basis with known date and time reference (expected to match date and time reference with CEMS where applicable),
   b. electronic format (e.g., excel spreadsheet), and
   c. kept for at least 5 years.
2. Installation test as described in Section 8.2:
   a. signed and sealed by an LEP if the PO is 1 MW or greater (subject to two or more SCT discharging into one common stack),
   b. electronic format (e.g., PDF document), and
   c. kept for at least 10 years.
3. Performance assessment as described in Section 8.5:
   a. signed and sealed by an LEP if the PO is 1 MW or greater (subject to two or more SCT discharging into one common stack) and where source testing or CEMS is not required by the Ministry,
   b. electronic format (e.g., PDF format), and

   c. kept for at least 10 years.

4. Source testing as described in Section 8.4:
   a. Pre-test plan approved by the Ministry,
   b. electronic format (e.g., PDF format), and
   c. kept for at least 10 years.

5. CEMS data as described in Section 8.3:
   a. CEMS Plan approved by the Ministry,
   b. hourly basis with known date and time reference (expected to match date and time reference with quantification of energy production),
   c. 24-hour rolling average calculated on an hourly basis,
   d. electronic format (e.g., excel spreadsheet), and
   e. kept for at least 10 years.

Appendix A - Original 1994 Guidance for Stationary Combustion Turbines

The guidance provided in this Appendix applies to Existing[8] stationary combustion turbines (SCT) using gaseous, liquid or solid-derived fuels for which the guidance in the main section of this Guideline does not apply. For any SCT, only one guidance format is to be applied since the definitions of terms and calculation procedures used to determine the concentration-based in-stack limits for nitrogen oxides (NOx) are different between the two guidance formats.

A1. Introduction

The document "National Emission Guidelines for Stationary Combustion Turbines" was published in December, 1992. The Ministry adopted these national guidelines as the basis for Policy A-5. The implementation of this policy is defined in this Appendix, as adapted for compatibility with the main section of this Guideline, from the original published in March 1994 by the Ministry as Guideline A-5.

A2. Definitions

The use of these definitions are only applicable for the content contained in Appendix A and should not be confused with the definitions set out and used in the main section of this Guideline.

Auxiliary Burners: this refers to the use of equipment to burn various types of fuel to reheat the combustion turbine exhaust gases.

Combustion Turbine: A combustion turbine is an engine which operates according to the Brayton thermodynamic cycle, in which fuel is burned and the products of combustion at a high temperature are allowed to expand through a rotating power turbine thus producing a net amount of motive power.

Combustion Turbine Facility: A combustion turbine facility includes the combustion turbine, the steam turbine (if applicable), the fuel handling equipment, related pollution control and flue gas handling equipment, and equipment required to directly recover energy from the exhaust gases. For simplification of thermal energy measurement, it excludes the downstream heating, cooling and industrial processes which utilize thermal energy recovered from the facility.

Contaminant: Means, for the purposes of this guideline, oxides of nitrogen of the form NO_X (NO and NO_2), oxides of sulphur of the form SO_X and measured as sulphur dioxide (SO_2) and the compound carbon monoxide.

[8] Capitalized terms “Existing” and “Modified” combustion turbines in Appendix A of this Guideline are defined in Section A2 and are capitalized throughout Appendix A for clarity.

Existing Combustion Turbine: Means a combustion turbine for which the Ministry received an original application for permission before [date to align with filing of amendments to Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions) made under the *Environmental Protection Act* if approved and filed with the Registrar of Regulations for Ontario] and includes those that have been subject to a physical or operational change which is intended to decrease the emission rate of an air pollutant (i.e., grams per second at the maximum power output capacity).

Gaseous Fuel: A fuel which, as received, at atmospheric conditions is a gas.

Liquid Fuel: A fuel which, as received, at atmospheric conditions is a liquid.

Lower Heating Value: Lower Heating Value (LHV) of the fuel is the energy released during combustion of the fuel, excluding the latent heat content of the water vapour component of the products of combustion.

Modified Combustion Turbine: Means a combustion turbine facility which has been subjected to physical change or change in method of operation which results or may result in:

- an increase in emissions (in grams per second at maximum capacity) of any contaminant; or,
- the emission of a contaminant which was not previously emitted.

Oxides of Nitrogen (NO_X): NO_X refers collectively to nitric oxide (NO) and nitrogen dioxide (NO_2) expressed as a nitrogen dioxide equivalent.

Peaking Combustion Turbine: A peaking combustion turbine is a combustion turbine which is ordinarily used to supply electric or motive power at periods of high demand or during unforeseen outages. Such a unit will not usually operate more than 7,500 hours in any 5 year period and, in those years, a total of no more than 3,000 hours during the months of May, June, July, August and September.

Pre-Test Plan: A summary of the sampling protocols and testing to be employed by the proponent during emission source testing of the Combustion Turbine.

Reference Conditions: refers to a reference state of 15 degrees Celsius ambient temperature, 60 percent relative humidity and 101.3 kiloPascals barometric pressure.

Solid-Derived Fuel: A fuel which, as burned, is derived from biomass or by some process such as gasification or liquefaction of coal.

Stand-By Combustion Turbine: A stand-by combustion turbine refers to a combustion turbine which operates less than 100 hours per year and is not required for the supply of energy or motive power to meet normal system operational requirements.

Thermal Efficiency: thermal efficiency is the fraction of the total energy input which is transformed into net useful energy output, usually expressed as a percentage on a lower heating value basis.

A3. Abbreviations

Abbreviation	Definition
ECA	Environmental Compliance Approval
MW	Megawatt of power
g	gram
GJ	gigaJoule, (10^9) Joules of Energy
ppmv @ 15% O_2	parts per million, on a volume basis, at 15 percent oxygen content in the exhaust gases
NO_X	Oxides of nitrogen
CO	Carbon monoxide
SO_2	Sulphur dioxide

A4. Applicability of the Appendix

This Appendix applies to Existing and, under certain circumstances, Modified combustion turbines as defined in the Definitions, Section A2. The following are exempt from this Appendix:

- stand-by combustion turbines;
- combustion turbines used for emergency duty;
- combustion turbines used in research, development, and field demonstrations;
- combustion turbines under repair (including temporary replacement units being used while the original unit is under repair) or being tested;
- peaking combustion turbines smaller than 3 MW.

General Notes

1. In the case where multiple Existing small combustion turbines are installed instead of a single large unit, the applicable unit size for the purposes of this Appendix will be the sum of the individual unit power ratings (for all Existing Combustion Turbines). While it is recognized that operational requirements may dictate the use of several units, multiple small units should not be used to evade the more stringent limits applicable to larger units.
2. In the case where a combustion turbine facility uses auxiliary burners, the Appendix limits apply to all fuel consumed by the combustion turbine facility. The fuel used in the auxiliary burners should be treated as if it had been burned in the combustion turbine. However, this is not intended to apply to situations where the downstream burners have a larger heat input

than the combustion turbine such as the case when a combustion turbine provides combustion air to a large utility boiler.

3. To determine the useful energy output over and above electrical or shaft power production, it is only necessary to measure the difference between the energy of the thermal fluids leaving and returning to the combustion turbine facility, and to demonstrate that the bulk of this energy is extracted in a useful application. This avoids having to individually measure the energy consumed by each downstream thermal energy application process in determining the heat output allowance.

A5. Emission limits

A5.1 Emission Limits for NO_X

The emission limits for various types of combustion turbines are determined by calculation of the allowable mass of NO_X (grams) per unit output of shaft or electrical energy (gigaJoules), as well as an allowance for an additional quantity of NO_X emitted if useful energy is recovered from the exhaust gas as heat. Allowable emissions equal:

$$(\text{Power output x A}) + (\text{Heat output x B}) = \text{grams of } NO_2 \text{ equivalent}$$

where, Power output is the electricity and shaft power energy production of the combustion turbine, expressed in gigaJoules on an hourly basis (3.6 GJ per MW-hour).

Heat output is the total useful heat energy recovered from the combustion turbine as heat, expressed in gigaJoules (hourly basis).

"A" and "B" are the allowable emission rates, expressed in grams per gigaJoule, for the facility's power and heat recovery components respectively, as summarized below.

Table A1: Power output allowance "A" (g/GJ) Non-Peaking Turbines

Range	Natural Gas	Liquid Fuel
Less than 3 MW	600	1,250
3 – 20 MW	240	460
Over 20 MW	140	380

Table A1: Power output allowance "A" (g/GJ) Peaking Turbines

Range	Natural Gas	Liquid Fuel
Over 3 MW	280	530

Notes:

- The 3 and 20 MW break points refer to the power output of the combustion turbine (not including any steam turbine or heat recovery).
- The value of "A" has been set at 500 g/GJ for solid-derived fuels, which recognizes that the competing alternative technology option is a conventional coal-burning steam electric power plant.

Table A2: Heat recovery allowance "B" (g/GJ) for All Units

Natural Gas	Liquid	Solid-derived
40	60	120

A5.2 Emission limit for carbon monoxide (CO)

For units covered by the NO_X provisions of this Appendix, emissions of CO corrected to Reference Conditions at 15 percent oxygen and on a dry volume basis should not exceed 60 parts per million per volume basis (ppmv) at the combustion turbine's power rating.

A5.3 Emissions of Sulphur Dioxide (SO_2)

SO_2 emissions from combustion turbines can be limited by using low sulphur content fuels, or by using technologies which reduce the fuel sulphur content or which capture SO_2 emissions in the exhaust. SO_2 emissions should not exceed the following limits:

- Liquid and Gaseous Fuels: For non-peaking units, 800 grams per gigaJoule of shaft, electrical and heat energy output, and for peaking units, 970 grams per gigaJoule of output.
- For Solid-Derived Fuels: 770 grams per gigaJoule of shaft, electrical and heat energy output for those fuels whose uncontrolled SO_2 emissions based on fuel sulphur content would be between 770 and 7,700 g/GJ of output, or a minimum of 90% sulphur capture for those fuels whose uncontrolled SO_2 emissions based on fuel sulphur content would be greater than 7,700 g/GJ of output.

However, units with a power rating of less than 3 MW which are used exclusively to power natural gas field compressors upstream of natural gas processing facilities are exempt from the SO_2 limits.

A6. Implementation of Appendix A

The expectations of this Appendix A will be implemented through conditions on Environmental Compliance Approval (ECA) issued for units where the Ministry received the application for ECA on or after November 30, 1994 and before [date to align with filing of amendments to Ontario Regulation 1/17 (Registrations Under Part II.2 of the Act – Activities Requiring Assessment of

Air Emissions) made under the *Environmental Protection Act* if approved and filed with the Registrar of Regulations for Ontario].

To simplify the record keeping and compliance monitoring procedures of the proponent and Ministry abatement staff, respectively, the limits for NO_X, CO and SO_2 (if applicable) will be expressed on the ECA as a concentration (ppmv). Procedures to convert emission limits to ppmv (Reference Conditions and 15% Oxygen on a Dry Volume Basis) are described below:

Oxides of Nitrogen (NO_X)

Emission Limit (ppmv @ 15% O_2) = C × E ⁄ D

where,

C = Combined power & heat output allowance (g/GJ output)

= (Power Output × A ⁄ Power + Heat Output) + (Heat Output × B ⁄ Power + Heat Output)

A, B are from Tables A1 and A2, Section A5

Heat output and Power output will be provided by the proponent.

E = Efficiency factor at maximum rating and reference conditions

= Thermal Efficiency (%) of Combustion Turbine and Heat Recovery ⁄ 100

The thermal efficiency will be provided by the proponent.

D = Fuel constant

(The following fuel constants can be used for natural gas or typical fuel oils):

= 1.70 g NO_2 per GJ of heat input per ppmv @ 15% O_2 for natural gas fuel

= 1.77 g NO_2 per GJ of heat input per ppmv @ 15% O_2 for liquid fuel

Carbon Monoxide (CO)

60 ppmv @ 15% O_2 as per Section A5.2 of this Appendix.

Note: A reference condition of 15% O_2 by volume-dry has been selected to reflect typical operating conditions for stationary combustion turbines.

Sulphur Dioxide (SO_2)

The procedure is the same as the one described above for NO_X:

Emission Limit (ppmv @ 15% O_2) = C × E ⁄ D where,

C = Output Allowance, as indicated in Section A5

E = Efficiency Factor; calculated the same as above.

D = Fuel Constant

= 2.37 g SO_2 per GJ of heat input per ppmv @ 15% O_2 for natural gas fuel

= 2.46 g SO_2 per GJ of heat input per ppmv @ 15% O_2 for liquid fuel

Alternatively, the SO_2 limit can be expressed as an equivalent weight percent of sulphur in the fuel.

A7. Verification of compliance with emission limits

To confirm that the stationary combustion turbine facility has the ability to operate in compliance with the provisions of this Appendix and the ECA, source testing or continuous emission monitoring will be expected. The following sections provide the necessary verification procedures:

A7.1 Continuous emission monitoring (CEM) parameters

Applicability: Non-peaking combustion turbines larger than 25 MW power output that are used to generate electricity.

CEM devices should be provided to non-peaking units larger than 25 MW for the measurement of NO_X, CO and O_2 according to the United States Environmental Protection Agency performance specification #2 (for NO_X, with a relative accuracy requirement of 10%), #3 (for O_2), and #4 (for CO) under 40CFR60, Appendix B of the United States Federal Register.

SO_2 emissions should be estimated (if applicable) based upon a mass balance and the expected range of sulphur content in liquid and solid fuels used by the combustion turbine.

A7.2 Source testing parameters

Applicability: non-peaking combustion turbines equal to or smaller than 25 MW power output; non-peaking combustion turbines larger than 25 MW power output that are not used to generate electricity; and all peaking turbines greater than 3 MW.

Source Testing for Non-Peaking Combustion Turbines which are equal to or less than 25 MW should be conducted for NO_X, CO, and SO_2 (if applicable) initially, after commissioning, and thereafter every 2 calendar years. Three (3) source tests should be conducted at maximum rating or at the maximum load achievable at the time of testing.

Source tests for Peaking Combustion Turbines should be conducted for NO_X, CO and SO_2 (if applicable) initially, after commissioning, only. Three source tests should be conducted at maximum rating or at the maximum load achievable at the time of testing.

All source tests should be conducted according to the Ontario Source Testing Code and the United States Environmental Protection Agency Method 7E, 6C and 10B for NO_X, SO_2 and CO, respectively. A pre-test plan for the initial source testing campaign should be submitted to the Ministry. The Ministry should be notified at least 1 month in advance of the commencement of any source testing and on an auditing basis; the Ministry may witness the source testing.

A7.3 Verification of thermal efficiency

Applicability: Existing and Modified combustion turbines that are not exempt from this Appendix.

The emission concentration limits for NO_X and SO_2, that will be included on the ECA for the Combustion Turbine, are derived from the Power and Heat Output Allowances included in section A5.1 of this Appendix and the anticipated thermal efficiency provided by the proponent. Therefore, to ensure the validity of the estimated thermal efficiency, testing of the Combustion Turbines thermal efficiency will be necessary.

A verification of the average operating thermal efficiency of a Combustion Turbine should be conducted whenever there is source testing or in the case of units equipped with CEM devices initially and thereafter every 2 calendar years. The thermal efficiency verification should provide measurements (at maximum rating or at the maximum load achievable at the time of testing over an averaging period of not less than 3 hours) to determine the following parameters:

1. Power Output (MW): based upon measurements of shaft and electrical power output.
2. Heat Output (MW): based upon total heat energy recovered from the combustion turbine exhaust gases (eg. based upon measurements of inlet and outlet enthalpy of water/steam in the case when water heaters or steam generators are used to extract heat from the exhaust gases).
3. Fuel Flow (m^3/s) or (kg/s).
4. Lower Heating Value (LHV) of the Fuel (MJ/m^3) or (MJ/kg).
5. Ambient air temperature, barometric pressure and relative humidity.
6. Date, time and duration of test.

The thermal efficiency of the Combustion Turbine should be calculated as follows:

$$E = (\text{Output}/\text{Input}) \times 100\%$$

$$= ((\text{Power} + \text{Heat Output})/(\text{Fuel Flow} \times \text{LHV})) \times 100\%$$

and converted to Reference Conditions.

If the measured thermal efficiency is less than the anticipated thermal efficiency (with a tolerance of 0.05 multiplied by the anticipated thermal efficiency) used to derive the emission concentration limits on the ECA then the proponent should notify the Ministry and the concentration limits on the ECA should be revised accordingly.

A7.4 Demonstration of compliance

For units equipped with continuous emission monitoring devices compliance is demonstrated if the monitored contaminant emission results, on a 24 hour rolling average basis, are less than the appropriate emission concentration limits of the ECA. For units that regularly conduct emission measurements, compliance is demonstrated if the average of the three source tests is less than the appropriate emission concentration limits of the ECA.

A8. Record keeping parameters

The proponent of a Combustion Turbine Facility will have the responsibility of ensuring compliance with the requirements of the ECA and should maintain records of compliance according to the following sections.

A8.1 Record keeping for units equipped with CEM devices

Raw data from the CEM devices in the form of a strip chart or computer printout or computerized format.

A monthly summary of 24 hour average readings from the CEM devices should be maintained and provided with the following information:

- Date, start time and end time for each 24 hour averaging period;
- Oxygen reading (% by volume-dry) and stack gas temperature (°C);
- 24 hour average concentration of NO_X and CO (ppmv @ 15% O_2);
- Results of daily zero and span calibrations of the CEM device: measurements from the zero calibration, span gas concentration and CEM device readings of the span gas concentration;
- standard deviation of the measurements for each 24 hour average period.

A8.2 Record keeping for source testing

A report should be completed within 6 months of commencement of source testing. The results of each testing campaign should provide the following information:

- Date, time and duration of each test;
- Ambient air temperature, barometric pressure and relative humidity during test;
- The oxygen (% by volume) concentration and stack gas volumetric flow rate (m^3/s at Reference Conditions);

- Emission concentrations of NO_X, CO and SO_2 (ppmv @ 15% O_2);
- Stack gas temperature (°C);
- Average of emission concentration readings (ppmv @ 15% O_2) for the 3 tests conducted.

A8.3 Record keeping for thermal efficiency verification

A summary of the results of the thermal efficiency verification should be completed within 6 months of commencement of the efficiency testing and should provide the following information:

- Date, time and duration of test;
- Ambient air temperature, barometric temperature and relative humidity during test;
- Electrical Power Output (MW);
- Shaft Power Output (MW);
- Heat Output (MW);
- Steam Flow (kg/s);
- Steam Pressure (kPa);
- Steam Temperature (°C);
- Feedwater Temperature (°C);
- Fuel Flow including auxiliary burners (m^3/s or kg/s);
- Fuel LHV (MJ/m^3 or MJ/kg).

All of the above record keeping (CEM device raw data, 24 hour average CEM device data; test and summary reports) should be maintained for a minimum of 2 years and should be made available to the Ministry upon request.

Appendix B - Sample Calculations Results

A series of sample calculations results for four (4) scenarios are presented below for natural gas fired combustion turbine systems (including both simple cycle and combined cycle configurations), separately each for: 1) power generation and 2) cogeneration combustion turbine system configurations as follows:

1. Microturbine simple cycle combustion turbine system
2. Mechanical simple cycle combustion turbine system
3. Industrial simple cycle combustion turbine system
4. Utility scale power plant with combined cycle combustion turbine system

All values expressed in parts per million by volume (ppmv) in this Appendix are corrected to 15% oxygen at reference conditions. All values expressed in gigajoules per hour (GJ/hr) are based on higher heating value (HHV). Thermal efficiency is expressed on a GPL basis (where it is understood that EPL will always be a higher thermal efficiency than the GPL).

To assist with interpretation, the Table number or Equation number from the main section of the Guideline is included in parenthesis next to the Parameter description, where relevant.

The inclusion of a Rankine cycle turbine in any scenario could be either an Organic Rankine Cycle (ORC) turbine or a steam turbine. These are secondary power generating devices and should not be confused with the combustion turbine which operates according to the Brayton cycle.

The estimated in-stack concentration for NOx are based on a ratio of 95% nitric oxide (NO) and 5% nitrogen dioxide (NO_2) where the total NOx is expressed as a nitrogen dioxide equivalent.

Section B.1 – Power generation

A series of four (4) scenarios are presented below with specific parameters as follows:

1. Microturbine POSC combustion turbine system (70 kW power output, non-peaking)
2. Mechanical POSC combustion turbine system (3 MW power output, non-peaking)
3. Industrial POSC combustion turbine system (15 MW power output, non-peaking)
4. Utility scale power plant using a combined cycle combustion turbine system with an auxiliary burner (100 MW power output, peaking)

Table B.1.1 – Energy Calculations

Parameter	Units	Site 1	Site 2	Site 3	Site 4
Fuel input to combustion turbine	GJ/hr	1.0	40	190	400
	MW	0.3	11	53	111
Fuel input to auxiliary burner	GJ/hr	-	-	-	270

Parameter	Units	Site 1	Site 2	Site 3	Site 4
	MW	-	-	-	75
Power output, combustion turbine	MW	0.07	3.0	15	45
Power output, Rankine cycle turbine	MW	-	-	-	55
Total power output	MW	0.07	3.0	15	100
Thermal efficiency (Equation 10)	%	25.2	27.0	28.4	53.7

Table B.1.2 – Emission Calculations

Parameter	Units	Site 1	Site 2	Site 3	Site 4
F-factor for natural gas	DSm³/GJ	240	240	240	240
Output-based NOx emission limit (Table 1)	g/GJ	290	500	140	140
Calculated maximum NOx emission rate (Equation 5)	g/hr	73	5,400	7,560	50,400
Calculated maximum concentration-based NOx emission limit (Equation 2)	ppmv	45.7	84.5	24.9	47.1
Applicable concentration-based NOx emission limit (Table 2 or Equation 8)	**ppmv**	**42**	**75**	**24.9**	**47.1**

Table B.1.3 – Estimated In-Stack Measured Values at Applicable Limit

Parameter	Units	Site 1	Site 2	Site 3	Site 4
Nitric oxide (NO) at 95%	ppmv	26.1	46.6	15.5	29.3
Nitrogen dioxide (NO_2) at 5%	ppmv	2.1	3.8	1.2	2.4

For reference, the thermal efficiency for POSC SCTs that use natural gas as a fuel and equates to the output-based NOx limits with concentration-based NOx limits are as follows:

- Non-peaking SCT – mechanical drive ≥ 1 and < 4 MW = 24%
- Non-peaking SCT – electricity generation ≥ 1 and < 4 MW = 23.1% (this value may be used for peaking SCT although it is not provided in the 2017 ECCC guideline)
- Non-peaking SCT and peaking SCT ≥ 4 and ≤ 70 MW = 28.5%
- Non-peaking SCT > 70 MW = 28.2%
- Peaking SCT > 70 MW = 28.5%

Section B.2 – Cogeneration

A series of four (4) scenarios are presented below with specific parameters as follows:

1. Microturbine simple cycle combustion turbine system (70 kW power output, 140 kW heat recovery, non-peaking)
2. Mechanical simple cycle combustion turbine system (3 MW power output, 5.7 MW heat recovery, non-peaking)
3. Industrial simple cycle combustion turbine system with auxiliary burner (15 MW power output, 50 MW heat recovery, non-peaking)
4. Utility scale power plant using a combined cycle combustion turbine system with an auxiliary burner (100 MW power output, 60 MW heat recovery, non-peaking)

Table B.2.1 – Energy Calculations

Parameter	**Units**	**Site 1**	**Site 2**	**Site 3**	**Site 4**
Fuel input to combustion turbine	GJ/hr	1.0	40	190	400
	MW	0.3	11	53	111
Fuel input to auxiliary burner	GJ/hr	-	-	90	270
	MW	-	-	25	75
Power output, combustion turbine	MW	0.07	3.0	15	45
Power output, Rankine cycle turbine	MW	-	-	-	55
Total power output	MW	0.07	3.0	15	100
Power efficiency	%	25.2	27.0	28.4	53.7
Heat recovery, combustion turbine	MW	0.14	5.7	32	30
Heat recovery, auxiliary burner	MW	-	-	18	30
Total heat recovery output	MW	0.14	5.7	50	60
Heat recovery efficiency	%	50.4	51.3	64.3	32.2
Thermal efficiency (Equation 10)	%	75.6	78.3	83.6	86.0

Table B.2.2 – Emission Calculations

Parameter	**Units**	**Site 1**	**Site 2**	**Site 3**	**Site 4**
F-factor for natural gas	DSm^3/GJ	240	240	240	240
Cogeneration coefficient	g/GJ	40	40	40	40
Output-based NOx emission limit (Table 1)	g/GJ	290	500	140	85
Calculated maximum NOx emission rate (Equation 6)	g/hr	79	5,628	9,560	33,000
Calculated maximum concentration-based NOx emission limit (Equation 2)	ppmv	49.2	88.0	21.4	30.8
Applicable concentration-based NOx emission limit (Table 3 or Equation 8)	**ppmv**	**60**	**100**	**21.4**	**30.8**

Table B.2.3 – Estimated In-Stack Measured Values at Applicable Limit

Parameter	**Units**	**Site 1**	**Site 2**	**Site 3**	**Site 4**
Nitric oxide (NO) at 95%	ppmv	37.3	62.1	13.3	19.2
Nitrogen dioxide (NO_2) at 5%	ppmv	3.0	5.0	1.1	1.5