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National Pollutant Inventory

Emission Estimation Technique Manual

for

Fossil Fuel Electric Power Generation
Version 2.4
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Disclaimer

The Manual was prepared in conjunction with Australian States and Territories according to the National Environment Protection (National Pollutant Inventory) Measure.

While reasonable efforts have been made to ensure the contents of this Manual are factually correct, the Australian Government does not accept responsibility for the accuracy or completeness of the contents and shall not be liable for any loss or damage that may be occasioned directly or indirectly through the use of, or reliance on, the contents of this Manual.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.4 – 15 March 2005).

Page	Outline of alteration
Table 14	Corrected oxides of nitrogen emission factor for natural gas.

Technique EET Manual (Version 2.3 – 14 September 2004).

Page	Outline of alteration
Table 14	Corrected PM_{10} emission factor for diesel.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.2 – 8 September 2004).

Page	Outline of alteration
Tables 7, 12 and 14	Corrected or updated emission factors.
References	Added more precise references for tables 12 and 14.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.1 – 12 July 2004).

Page	Outline of alteration
Table 12 page 45	The manual was missing the emission factors relating to PM_{10} emissions from oil and distillate combustion.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.0 – 12 December 2003)

Page	Outline of alteration
all	The manual has been completely revised and updated with emissions factors for most electric power generation facilities. The data has been obtained through a monitoring/testing program to replace some emission factors sourced from the United States Environmental Protection Agency (USEPA).

EMISSION ESTIMATION TECHNIQUES
FOR
FOSSIL FUEL ELECTRIC POWER GENERATION

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FOSSIL FUEL ELECTRIC POWER GENERATION

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1 Introduction

The National Pollutant Inventory (NPI) handbooks assist facility operators to estimate emissions for reporting to the NPI. NPI handbooks consist of the NPI Guide and one or more Emission Estimation Technique (EET) Manuals.

The first step to estimating emissions is to determine if the facility operator needs to report to the NPI as detailed in the NPI Guide. The NPI Guide outlines the steps for determining if a facility operator needs to report to the NPI.

This Manual describes the procedures and recommended approaches for estimating emissions from facilities engaged in fossil fuel electric power generation. It considers combustion and non-combustion sources of emissions to air, water and land for the fossil fuel electric power generation industry. Other NPI manuals can be used to estimate the emissions from facilities that are not covered in this manual.

The activities covered by this Manual apply to facilities primarily engaged in the conversion of fossil fuels (particularly coal, natural gas, and liquid hydrocarbons) into electricity.

EET MANUAL:	Fossil Fuel Electric Power Generation
HANDBOOK:	Electricity Supply
ANZSIC CODES :	361

The Electricity Supply Association of Australia Ltd (ESAA) wrote this Manual on behalf of and in conjunction with the Australian Government. It has been developed through a process of national consultation involving State and Territory environmental authorities and key industry stakeholders.

The Manual was revised by ESAA in March 2002. The review document proposed a number of changes to the Manual based on recently available information and improved emission estimation techniques. The scientific review report (Reference: Pacific Power International 2002) and detailed references are held in the library of the Australian Department of the Environment and Heritage. The library can be contacted via the Department's Internet site (www.deh.gov.au).

1.1 Outline of this manual

Below is an outline of the goals of the different parts of this manual.

Section	Details
2	Description of the key process involved in the generation of electric power from fossil fuel
3	Details of the sources of pollutant emissions for fossil fuel electric power generation industry
4	Information about the emission factor rating (EFRs) used
5	Details of the main pollutant emission estimation techniques as they apply to the fossil fuel electric power generation industry.
6	Emission factors and related equations for the estimation of pollutant emissions from the fossil fuel electric power generation industry
7	A summary of control technologies for the electric power generation industry
8	References cited in this manual
9	Glossary of terms and abbreviations used in this manual
Appendix A	Details of NPI substances relevant to fossil fuel electric power generation
Appendix B	Typical properties of Australian coal

2 Process Description

Over 85% of electricity generated during 1999-2000 was based on fossil fuel combustion (Reference: Electricity Supply Association of Australia 2001). Currently black coal is the largest source of fuel for electricity generation followed by brown coal, natural gas and petroleum oils.

Coal-bed methane is currently a minor fuel source for electricity generation. Non-fossil sources of fuel such as landfill gas and bagasse are also used for electricity production. In some cases these non-fossil fuels are "co-fired" with coal. Emission factors for coal-bed methane and non-fossil fuels are not included in this Manual.

Renewable sources of electricity generation such as wind power and solar power are making an increasing contribution.

Types of fossil fuel electricity generation facilities include:

- steam cycle facilities (commonly used for large base load facilities);
- gas turbines (commonly used for moderate sized peaking facilities);
- cogeneration and combined cycle facility (the combination of gas turbines or internal combustion engines with heat recovery systems); and
- internal combustion engines (commonly used for small remote sites or stand-by (emergency) generation).

Each of these facility types is considered in more detail in sections 2.1 to 2.4.

The combustion processes in fossil fuel power generation lead to the coincidental production of a number of NPI category 1 substances. Refer to the NPI Guide for more information about coincidental production and determining NPI reporting requirements (www.npi.gov.au).

For most Category 1 organic compounds, the coincidental production during combustion of fossil fuel will be below NPI threshold levels. In such cases, reporting may only be required if these organics are used in some other process at the facility. For example, reporting of some Category 1 substances may be triggered by liquid fuel use, in which case all emissions, including emissions from combustion, must be reported.

When estimating total emissions to air, land and water, be aware that only two significant figures are reported on NPI Internet reports and it is unlikely that the accuracy of estimates justify the provision of additional significant figures.

NPI reportable emissions from fossil fuel power stations are largely emissions from stacks, with water emissions from wet ash dams from some facilities also being a source of reportable emissions.

Chemical use within power stations tends to be relatively modest. Bulk chemicals are used to treat boiler water and cooling water for steam cycle facilities. Facilities need to assess whether the use of substances such as ammonia, chlorine and sulfuric acid will lead to the NPI reporting threshold being exceeded for those substances.

Coal storage and handling and ash storage may result in fugitive particulate emissions.

While maintenance activities such as degreasing of metal components may lead to emissions to air and water, the use of degreasers alone is unlikely to lead to the NPI reporting thresholds being exceeded for substances contained in these products.

This manual will assist you to estimate the emissions you may need to report to the NPI. It is your responsibility to report to the NPI if your facility exceeds reporting thresholds for NPI substances. Refer to the NPI Guide (www.npi.gov.au) for further information NPI reporting thresholds and the steps involved in reporting to the NPI.

2.1 Steam Cycle Facility

Most of the electricity generated in Australia is produced by steam cycle facility. Figure 1 is a basic flow diagram for a steam cycle facility.

In the Australian context, a steam cycle facility is based on the combustion of fossil fuel in a boiler to produce high pressure and high temperature steam that is expanded through a steam turbine coupled to an electricity generator. The steam is condensed for reuse in the cycle. Steam cycle facilities are typically used for large base load electricity generation. Fuels commonly used in Australia are black coal in New South Wales, Queensland and Western Australia, brown coal (or lignite) in South Australia and Victoria and natural gas in South Australia, Victoria, and Western Australia.

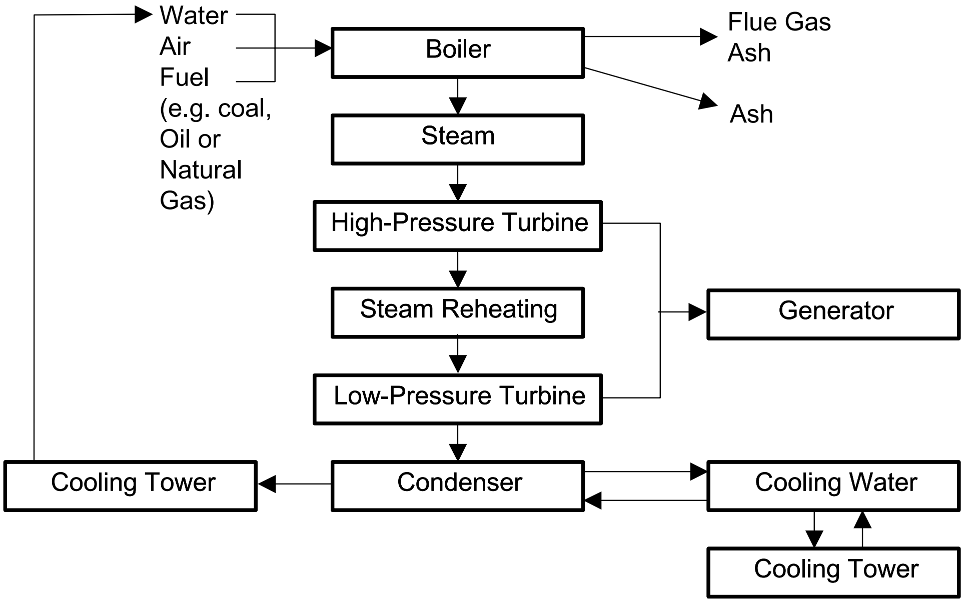
Fuel oil, lighter oils, natural gas, brown coal briquettes, or liquefied petroleum gas (LPG) are commonly used as auxiliary fuels (e.g. during start-up procedures).

The boiler water is commonly treated to reduce corrosion and scaling in the boiler tubes. Cooling water used to condense the steam is often treated to reduce algal growth. Australian electricity generating companies (Reference: Personal communication from Electricity Supply Association 2004) highlight that the typical ranges of chemicals used in steam cycle power stations are:

Sulfuric acid	22 - 3840 tonnes per year
Ammonia	0.7 - 400 tonnes per year
Chlorine	0 - 102 tonnes per year

Wet cooling towers, commonly used to dissipate heat from the cooling water, may also be a minor source of particulate emissions.

Figure 1 Flow diagram for a steam cycle facility



2.1.1 Coal-Fired Steam Cycle

The characteristics and composition of coal vary more than those for other fuels commonly used in electricity production. Indicative properties and composition of Australian coals used for electricity generation in Australia are included in Appendix B. Because of the variation in coal properties it is difficult to characterise emission factors that apply to the range of coals used in Australia.

Coals are usually pulverised prior to combustion. Particulate material (e.g. fly ash or particulate matter) in gas streams from the combustion process are captured by electrostatic precipitators or fabric filters (FF – also called baghouses). Ash is also extracted from the bottom of the boiler (bottom ash). Ash is transported to ash dams as a slurry, dense phase (paste), or dry. Fly ash from some power stations is used for blending with cement.

Ash is composed of modified coal mineral matter, i.e. primarily compounds of silicon, aluminium, iron, calcium, manganese, potassium, sodium and titanium which form a matrix for traces of compounds of other metals. Ash composition depends on the coal properties, combustion technology and combustion conditions. Usually only very small amounts of ash are released to air.

The major emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), and sulfur dioxide (SO_2). There are much lower emissions of metals (usually reported as metal & compounds for the NPI) and organic compounds. Carbon dioxide and water vapour are not NPI substances and are not reported to the NPI.

Common boiler types used in Australia can be divided into wall firing (i.e. burners on one or two walls), or tangential firing (i.e. corner burners that create a circular shaped flame).

Coal and ash storage and handling facilities, and bulk hydrocarbon storage associated with power station operations, can lead to fugitive dust (i.e. coal or ash) and hydrocarbon emissions to air respectively.

2.1.2 Gas and Oil-Fired Steam Cycle

A major difference between coal-fired facilities and gas or oil-fired facilities, is that gas and oil facilities burn the fuel with minimal on-site processing before combustion. Generally, they do not have control equipment to collect particulate matter, as emissions of particulate matter are low.

Emissions to air include carbon dioxide (CO_2), water vapour, oxides of nitrogen (NO_x), carbon monoxide (CO), minor emissions of metals and metal compounds and organics, and sulfur dioxide (SO_2) for oil firing. Carbon dioxide and water vapour are not NPI substances and are not reported to the NPI.

Bulk hydrocarbon storage can be a source of emissions of Total Volatile Organic Compounds (TVOCs) and of individual hydrocarbon substances due to evaporative losses from storage tanks.

2.2 Gas Turbine

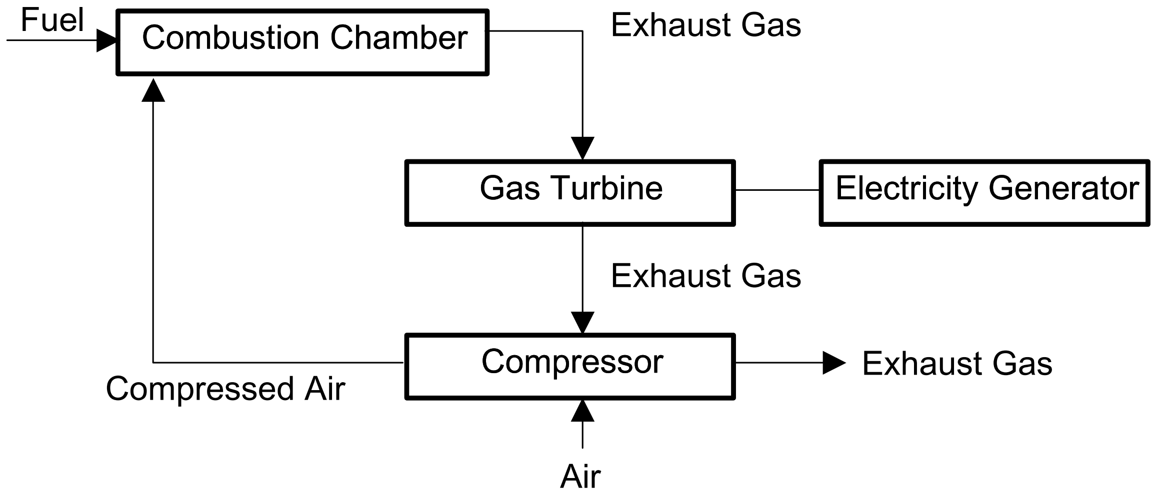
The gas turbine cycle relies on the expansion of very high temperature compressed gas through a gas turbine connected to an electricity generator. To achieve this, air is compressed and mixed with the fuel (usually natural gas or distillate), and burnt in a combustion chamber(s) prior to expansion through the turbine. Figure 2 illustrates a simple open cycle gas turbine facility.

Gas turbine facilities are generally physically smaller and produce less electricity than steam cycle facilities and can be operated with short start-up periods. They are commonly used to generate electricity at peak load periods. Gas turbines are also used as standby (i.e. emergency) facilities. Occasionally, gas turbine facilities are used for base load operations.

Emissions to air from a gas turbine facility include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), and minor emissions of metals and metal compounds and organics. Carbon dioxide and water vapour are not NPI substances and are not reported to the NPI.

Emissions to water from gas turbine facilities tend to be minor and relate to maintenance activities. Bulk hydrocarbon storage can be a source of emissions.

Figure 2 Flow diagram for a gas turbine facility



2.3 Cogeneration, including Combined Cycle Gas Turbine

Cogeneration is a special application of gas turbine or stationary engine technology. Cogeneration utilises the heat from the exhaust of the gas turbine, engine, or boiler, to heat water or raise stream for either domestic or industrial processes.

In combined cycle gas turbine facility, hot exhaust gases from the gas turbine are used to raise steam in a heat recovery steam generator. The steam is used to drive a steam turbine and electrical generator.

Cogeneration and combined cycle facilities can operate for considerable periods (to supply the heat and electricity requirements) and have overall thermal efficiencies (measure of energy utilisation) greater than simple gas turbines or stationary engine facilities.

Emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), hydrocarbons, and minor emissions of metals and metal compounds. Due to the higher conversion efficiencies achieved, emissions per unit of energy output from cogeneration/combined cycle facility are significantly lower than from an open cycle facility.

Emissions to water sources relate to the specific configuration of the heat recovery system, which may include water treatment and facility maintenance.

2.4 Internal Combustion (Stationary) Engines

Internal combustion engines using either petrol, natural gas, distillate, or LPG, coupled to electricity generators. Engines are commonly used to provide electricity in remote sites and stand-by (emergency) facilities.

Usually, internal combustion engines are relatively small units compared to those considered above.

Emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), hydrocarbons, and minor emissions of metals and metal compounds. Bulk organic liquid storage may be a source of emissions.

Minor emissions to water can relate to engine cooling systems and facility maintenance.

3 Sources of Emissions

This section examines the emissions to the destination of air, land and water from fossil fuel electric power generation facilities. When reporting to the destination of pollutant emissions needs to be determined. For additional information about the destination of pollutant emissions see the NPI Guide (www.npi.gov.au).

3.1 Emissions to Air

Emissions to air can be categorised as either stack (or point sources) or fugitive (or non-point sources).

Fugitive emissions

Fugitive emissions are emitted to air from sources not associated with a specific process, but scattered throughout the plant. Examples of fugitive emissions include dust from stockpiles, volatilisation of vapour from open vessels, and material handling. Emissions emanating from ridgeline roof-vents, louvres, and open doors of a building, as well as equipment leaks, and leaks from valves and flanges are also examples of fugitive emissions. With appropriate management, these emission sources are expected to be minor for power stations. Emission factors are the usual method for estimating emissions from fugitive sources. Refer to the Fugitive Emissions NPI manual for more information about estimating emissions from fugitive sources.

Point source emissions

Point source emissions are emitted from a stack or vent to air, usually for a specific section of a facility. Emission control equipment (e.g. an electrostatic precipitator or fabric filter (baghouse)) can be used to decrease point source emissions.

Summary of sources of emissions to air

Sources of emission to air for fossil fuel electric power generation include:

- fuel combustion products (from stacks);
- fugitive emissions from coal stockpiles and handling equipment;
- fugitive emission from ash storage;
- additives used for water treatment;
- organic compounds from bulk hydrocarbon storage tanks; and
- solvents used for degreasing metal components.

Table 1 summarises the emissions to air from fossil fuel electric power generation that are likely to be reportable to the NPI.

Table 1 Likely emissions to air from fossil fuel electric power generation

Technology/Fuel	Inputs	Potential emissions to air
Gas turbine/distillate	distillate, auxiliary fuel (LPG), lubricants, degreasers, demineralised water water (cogeneration/combined cycle)	NO_X, SO_X, CO, particulates (including PM_{10}), trace metals & compounds, OCs
Gas turbine/natural gas	natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers, demineralised water (cogeneration /combined cycle)	NO_X, SO_X (very low), CO, OCs and trace metals & compounds
Internal combustion engine/distillate	distillate, lubricants, degreasers, coolant	NO_X, SO_X, CO, trace metals & compounds, OCs, and PM_{10}
Internal combustion engine/natural gas, LPG	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	NO_X, SO_X (very low), CO, OCs, PM_{10}, and trace metals & compounds.
Steam cycle/natural gas	natural gas, auxiliary fuel (fuel oil, distillate, LPG), demineralised water, cooling water, lubricants, degreasers, water treatment chemicals	NO_X, CO, SO_X (very low), PM_{10}, OCs, and trace metals & compounds.
Steam cycle/oil	fuel oil, auxiliary fuel (natural gas, distillate, LPG), demineralised water, lubricants, degreasers	NO_X, SO_X, CO, particulates (including PM_{10}), trace metals & compounds, OCs,
Steam cycle/pulverised coal	coal, demineralised water, auxiliary fuel (fuel oil, natural gas, briquettes), lubricants, degreasers, water treatment chemicals	NO_X, CO, SO_X, particulates (including PM_{10}), fugitive dust, trace metals & compounds, OCs,

Notes:
1. CO - carbon monoxide
2. NO_X - oxides of nitrogen; include NO (nitric oxide) and NO_2 (nitrogen dioxide)
3. OCs - organic compounds; include total volatile organic compounds, and polycyclic aromatic hydrocarbons (PAHs)
4. SO_X - sulfur oxides; include SO_2 (sulfur dioxide), SO_3 (sulfur trioxide), and gaseous sulfates
5. PM_{10} – particulate matter that is less than 10 micrometres diameter

3.2 Emissions to Water

For more information about emissions to water see the NPI Guide (www.npi.gov.au).

Table 2 summarise possible emissions to water from fossil fuel electric power generation.

There is currently no emission factors included for emissions to water. Sources of emissions to water are primarily from steam cycle facilities and can include:

- Ash transport wastewater and discharge from wet ash dams;
- Boiler and cooling tower blowdown;
- Coal stockpile runoff;
- Floor drains;
- Metal and boiler cleaning waste (gas and water sides); and

- Water treatment facility discharges.

Table 2 Potential emissions to water from fossil fuel electric power generation

Technology/Fuel	Inputs	Potential emissions to water
Gas turbine/natural gas, distillate	Natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers, detergents, cooling system inhibitors	oil spills[1], degreasers[1], cooling system inhibitors, detergents
Internal combustion engine / natural gas, LPG, distillate	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	waste coolant[1], oil spills[1], degreasers[1], detergents
Steam cycle / pulverised coal, natural gas, oil	coal, demineralised water, auxiliary fuel (fuel oil, natural gas, briquettes), lubricants degreasers, water treatment chemicals/effluent, detergents	Chlorine, acids, alkalis, suspended solids, nitrogen, phosphorus, trace metals & compounds, oil spills[1], degreasers[1], detergents
Note: 1. due to infrequent, unplanned incidents		

3.3 Emissions to Land

For general information about emissions to land see the NPI Guide (www.npi.gov.au). Emissions to land are to the land on which the facility is located. Emissions to land include solid wastes, slurries, sediments, liquid spills and leaks, and chemicals used to control various environmental issues where these chemicals contain NPI-listed substances. These emission sources can be broadly categorised as:

- Groundwater;
- Surface impoundments of liquids and slurries; and
- Unintentional leaks and spills.

Ash disposal to an appropriately operated dam is considered to be a transfer. Transfers are currently NOT reported to the NPI.

However, discharges from the dam to the environment, (e.g. ash transport in wastewater to a stream) is within the scope of the NPI (as an emission to water or land).

Other potential emissions to land include chemical and/or oil spills.

Table 3 Potential emissions to land from fossil fuel electric power generation

Technology/Fuel	Inputs	Potential emissions to land
Gas turbine/natural gas, distillate	natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers	oil spills[1], wastes
Internal combustion engine/natural gas, LPG, distillate	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	oil spills[1], wastes
Steam cycle/pulverised coal, natural gas, oil	coal, demineralised water, auxiliary fuel (fuel oil, natural gas, briquettes), lubricants, degreasers, water treatment chemicals	ash, oil/chemical spills[1], metals & compounds, wastes
Note: 1. due to infrequent unplanned incidents		

4 NPI reporting thresholds.

A summary of the material in the NPI Guide (www.npi.gov.au) in relation to reporting thresholds is given below.

Category 1 and 1a Substances

- A Category 1 substance is only reportable if 10 tonnes or more of the substance is used during the reporting year.
- TVOCs is the only Category 1a substance for which the throughput threshold is 25 tonnes per annum (see the NPI Guide for more details).
- For the NPI "use" means material processed (e.g. crude oil throughput, production chemicals, drilling fluids), or coincidental production (e.g. substances contained in produced formation water, emissions from dehydrator regeneration etc).
- Substances in proprietary mixtures are not reported to the NPI or considered for reporting thresholds unless the substance is specified in a Material Safety Data Sheet or the facility operator could reasonably be expected to know that the substance is contained in the mixture.

The usage of each of the substances listed as Category 1 and 1a under the NPI must be estimated to determine if the substance has to be reported to the NPI. Emissions need to be estimated and reported to the NPI for each substance that exceeds the Category 1 or 1a threshold.

The total amount of each Category 1 and 1a substance 'used' must be calculated in order to determine whether the reporting threshold is exceeded. This involves developing a cumulative total for the use of each NPI substance from various sources.

Combustion related emissions of most Category 1 substances from fossil fuel electricity generation are unlikely to exceed the reporting threshold. However, the use of significant quantities of liquid fuel may trigger the Category 1 reporting threshold for a number of Category 1/1a substances, in which case emissions from all sources (evaporation, combustion) are required to be reported.

The following tables (5 through 16) provide emission factors for many organic compounds, where relevant to fossil fuel combustion, and cyanide (category 1 substance) for coal, natural gas and oil combustion in steam cycle and gas turbine facilities. Many of the organic compounds do not have combustion emission factors since they are not generally products of combustion.

Many of these substances will be in very small quantities in the exhaust gases, due to the efficient combustion processes and input fuel characteristics. Hence, data for Category 1 emission factors is less comprehensive compared to the common emissions such as oxides of nitrogen. The emission factors indicate that for the majority of these substances it is unlikely that the reporting threshold of 10 tonnes would be triggered by combustion at any facility.

However, reporting of some of these substances may be triggered because they are contained in liquid fuel used by facilities. If liquid fuel use causes a reporting threshold to be exceeded, all emissions of the substance for which the reporting threshold is exceeded must be estimated and reported to the NPI. This includes evaporation from storage tanks and from combustion. Additional information about estimating emissions from Fuel and Organic liquid storage and Combustion Engines is provided in manuals provided by the NPI (www.npi.gov.au).

Table 18 includes fuel use amounts that will trigger the reporting thresholds for liquid fuel constituents, where fuel concentration data are available.

Category 2a and 2b Substances

The reporting thresholds for Category 2a and 2b substances are based on either:

- fuel combusted (Category 2a - 400 tonnes per year or 1 tonne per hour and Category 2b - 2,000 tonnes per year); or
- energy used (Category 2b – 60 000 megawatt hours per year or rated at 20 megawatts).

If any of these reporting thresholds are exceeded then all emissions of the relevant substances must be reported to the NPI.

5 Emission Factor Rating

Every emission factor (EF) has an associated emission factor rating (EFR) code. The emission factors in section 6 of the manual all have been provided with an EFR code. This rating system is common to EETs for all industries and sectors and therefore, to all Industry Handbooks.

The EFR codes are based on rating systems developed by the United States Environmental Protection Agency (USEPA) and the European Environment Agency (EEA). Sources for all emission factors cited can be found in References section of this Manual. The EFR codes do not form part of the public NPI database. The EFR code provides information to facility operators about the accuracy of the EF.

When using emission factors, you should be aware of the associated EFR code and what that rating implies. An A or B rating indicates a greater degree of certainty than a D or E rating. The less certainty, the more likely that a given emission factor for a specific source or category is not representative of the source type. These ratings notwithstanding, the main criterion affecting the uncertainty of an emission factor remains the degree of similarity between the equipment/process selected in applying the factor, and the target equipment/process from which the factor was derived.

The EFR system is as follows:

A - Excellent
B - Above Average
C - Average
D - Below Average
E - Poor
U - Unrated

A number of the emission factors included in the Manual are unrated (U). This does not necessarily mean that the factors are unreliable, as in a number of cases they have been derived from “A” rated factors, or rely on facility-specific data, suggesting that they could be regarded as “above average”.

6 Emission Estimation Techniques - EETs

There are five types of emission estimation techniques (EETs) that may be used to estimate emissions from your facility:

- mass balance;
- engineering calculations (e.g. based on fuel composition);
- sampling or direct measurement;
- emission factors; and
- approved alternative EET.

More information about the five EET types can be found in the NPI Guide.

Select the EET (or mix of EETs) that is most appropriate for your purposes. For example, you might choose to use a mass balance to best estimate fugitive losses from pumps and vents, direct measurement for stack and pipe emissions, and emission factors when estimating losses from storage tanks and stockpiles.

If you estimate your emission by using any of these EETs, your data will be displayed on the NPI database as being of 'acceptable reliability'. Similarly, if the State or Territory environmental authority where the facility is located has approved the use of emission estimation techniques that are not outlined in this Handbook, your data will also be displayed as being of 'acceptable reliability'.

This Manual seeks to provide the most effective emission estimation techniques for the NPI substances relevant to this industry. However, the absence of an EET for a substance in this Manual does not necessarily imply that an emission should not be reported to the NPI. The obligation to report on all relevant emissions remains if NPI reporting thresholds have been exceeded.

In revising this manual, attempts have been made to present EETs for all relevant substances, for all combustion technologies. However, in some cases, it has not been possible to include an emission factor and an entry of "no data" is included in the relevant table. In these circumstances, facilities should endeavour to derive a facility-specific EET, but where this is not feasible there is no requirement to include an entry in the NPI report for that substance. In these circumstances the reporting space should be left blank. Reporting facilities should not enter "zero", unless the reason for such reporting is understood and documented and approval has been obtained from the relevant environmental authority.

You are able to use emission estimation techniques that are not outlined in this document (approved alternative EETs). You must, however, seek the consent of the State of Territory environment authority where the facility is located. For example, if your company has developed facility-specific emission factors, you may use these if approved by the relevant environmental authority.

In general, direct measurement may be the most accurate method for characterising emissions. However, for many substances emitted in small quantities, reporting based on direct measurement may show significant year-to-year variability due to measurement and analytical variability and uncertainty. In these cases the use of robust emission factors, based on facility-specific fuel and operating characteristics, may provide more consistent results. Additional direct measurement is not required for the NPI. Direct monitoring may be undertaken as an element of other EETs. In many circumstances the use of simple generic emission factors will provide the most effective means of estimating emissions for a particular substance.

The determination of the most appropriate EET to use for particular substances will require professional consideration. When in doubt as to the EET to use, officers responsible for preparing NPI returns could consider seeking advice from one of the following:

- the relevant state jurisdiction. See the NPI website (www.npi.gov.au) for contact details; or
- a suitably experienced professional.

You should note that the EETs presented in this Manual relate principally to average process emissions. Emissions resulting from non-routine events are rarely discussed in the literature, and there is a general lack of EETs for such events. However, it is important to recognise that emissions resulting from significant operating excursions and/or accidental situations (e.g. spills) will also need to be estimated. Emissions to land, air and water from spills must be estimated and added to process emissions when calculating total emissions for reporting purposes. The emission resulting from a spill is the net emission, i.e. the quantity of the NPI reportable substance spilled, less the quantity recovered or consumed during clean up operations.

6.1 Using direct measurement to estimate NPI pollutant emissions

Stack sampling test reports often provide emissions data in terms of kg/hr or grams/$m^3_{STP,dry}$ (dry standard cubic metre). Annual emissions for NPI reporting can be calculated from this data using Equations (1) or (2) below. Stack tests for NPI reporting should be performed under representative (i.e. normal) operating conditions, and in accordance with the methods, or standards, approved by the relevant environmental authority. Tests conducted specifically for the NPI may differ from stack tests undertaken for a State or Territory licence condition, which may require the test be taken under maximum emissions rating (i.e. where emissions are likely to be higher than when operating under normal operating conditions). However, the acceptability of using existing monitoring program data and test methods should be checked with your local environmental regulatory authority.

This Section shows how to calculate emissions in kg/hr based on stack sampling data, and how to convert this to an annual emission figure. Calculations involved in determining PM_{10} emissions are used as an example, although the same general methodology is applicable for most of the substances listed on the NPI.

Concentration

$$C_{PM} = C_f / V_{m,\,STP} \tag{1}$$

where:

C_{PM} = concentration of PM_{10} or gram loading (g/m^3)
C_f = filter catch (g)
$V_{m,STP}$ = metered volume of sample at STP (m^3), dry.
STP = standard temperature and pressure. 1 atmosphere (101.325) kPa and 273 degrees Kelvin.

(The mass concentration of a gas (C_{gas}) is obtained directly by measurement results in units g/m^3, or converted from units such as g/m^3, or parts per million by volume (ppmv), which may be on a wet or dry basis.)

Emission

$$E_{PM10} = C_{PM} \text{ x } Q_d \text{ x } 3.6 \tag{2}$$

where:

E_{PM10} = hourly emissions of PM_{10} in kg/hr
Q_d = stack gas volumetric flow rate ($m^3{}_{STP,dry}/s$)
3.6 = 3 600 seconds per hour multiplied by 0.001 kilograms per gram

With regards to emission controls for PM_{10}, in the absence of measured data, or knowledge of the collection efficiency for a particular piece of equipment, default values can be used. The default values are:

- 99.2% for electrostatic precipitators; and
- 99.8% for fabric filters.

Example 1 Estimating PM_{10} emission factors from monitoring information

PM_{10} emissions calculated using Equations 1 and 2, and the stack sampling data for the following monitoring information:

Total sampling time	7 200 sec
Moisture collected	395.6 g
Filter catch (C_f)	0.0851 g
Average sampling rate	1.67E-04 $m^3_{STP,dry}/s$
Standard metered volume ($V_{m,STP}$)	1.185 $m^3_{STP,dry}$
Volumetric flow rate (Q_d)	8.48 $m^3_{STP,dry}/s$
Exhaust gas temperature	25°C {298K}).

$$\begin{aligned} C_{PM} &= C_f / V_{m,\,STP} \\ &= 0.085 / 1.185 \\ &= 0.072 \text{ g/m}^3_{STP,dry} \end{aligned}$$

$$\begin{aligned} E_{PM} &= C_{PM} \text{ x } Q_d \text{ x } 3.6 \\ &= 0.072 \text{ x } 8.48 \text{ x } 3.6 \\ &= 2.01 \text{ kg/hr} \end{aligned}$$

Note:

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

To convert actual exhaust flows into STP, dry use:

$$Q_d = Q_a \text{ x } (1 - MC/100) \text{ x } (273/(T + 273)) \text{ x } (P_s/101.325) \qquad (3)$$

Q_d = stack gas volumetric flow rate ($m^3_{STP,dry}/s$)
Q_a = actual gas volumetric flow rate (m^3/s)
MC = moisture content of stack gas (% by volume)
T = actual stack gas temperature (°C)
P_s = Absolute stack gas pressure (kPa)

(Source: South Australian Environment Protection Agency, 1995)

The most appropriate method for determining emissions to the environment via wastewater is to use direct measurement. However, you may use other EETs, particularly mass balances, for the purposes of reporting to the NPI. Table 2 highlights some potential water emissions from fossil fuel electric power generation.

Concentration and flow data already measured for environmental compliance conditions, such as discharge licences, can be used as a cost effective EET. Alternatively, the current sampling and analysis program may be modified to include the flows and concentrations of NPI substances that the facility is obliged to report.

Identifying all the emissions to water, followed by a review of the NPI list of substances, should indicate the materials that require reporting. The next step is to determine the most appropriate EET for the substances for which you are required to provide a report.

While discharges to groundwater are generally not allowed by environmental legislation, any known discharges may be relevant to the NPI.

6.2 Using CEMS Data

Using CEMS (Continuous Emission Monitoring Systems) data to estimate emissions can be applicable to power stations with suitable equipment installed, or for facilities that undertake medium term monitoring that is representative of the power station operations over a year.

To monitor SO_2, NO_x, TVOCs, and CO emissions using a CEMS, you use a pollutant concentration monitor that measures concentration in parts per million by volume dry air (ppmvd). Flow rates should be measured using a volumetric flow rate monitor. Emission rates (kg/hr) are then calculated by multiplying the stack gas concentrations by the stack gas flow rates.

While it is possible to determine from this data the total emissions of an individual pollutant over a given time period (assuming the CEM operates properly all year long), an accurate emission estimate can be derived by adding the hourly emission estimates if the CEMS data is representative of typical operating conditions.

Although CEMS can report real-time hourly emissions automatically, it may be necessary to manually estimate annual emissions from hourly concentration data. This section describes how to calculate emissions for the NPI from CEMS concentration data. The selected CEMS data should be representative of operating conditions. When possible, data collected over longer periods should be used.

It is important to note that prior to using CEMS to estimate emissions, you should develop a protocol for collecting and averaging the data in order that the estimate satisfies the facility's State or Territory environment authority as a requirement for NPI emission estimations.

Table 4 Example CEM Output Averaged for a Power Facility Firing Fuel Oil

Measurement	O_2 (%V)	Concentration (C) (ppmvd)				Gas Flow Rate (Q) ($m^3_{stp,dry}/s$)	Oil Use Rate (AR_{hr}) (tonnes/ hour)
		SO_2	NO_X	CO	TVOCs		
1	10.3	150.9	142.9	42.9	554.2	8.52	290
2	10.1	144.0	145.7	41.8	582.9	8.48	293
3	11.8	123.0	112.7	128.4	515.1	8.85	270

Hourly emissions can be based on concentration measurements as shown in Equation (4) and Example 2.

$$E_i = (C \times MW \times Q \times 3\,600) / (V \times 1E{+}06) \quad (4)$$

where:

E_i = emissions of pollutant i, kg/hr
C = pollutant concentration in ppmvd
MW = molecular weight of the pollutant (kg/kg-mole)
Q = stack gas volumetric flow rate in $m^3_{STP,dry}/s$
3 600 = 3 600 seconds per hour
V = volume occupied by one mole of gas at standard temperature and pressure (22.4 m^3/kg-mole at 0°C and 1 atmosphere)

This may be applied to each hour that CEMS data is available for a year, and modified to account for time CEMS data is unavailable (weighted by load).

Alternatively, a less robust estimation of emissions in kilograms per year can be calculated by multiplying the emission rate in kg/hr, by the number of actual operating hours (OpHrs) as shown in Equation (5) and Example 2.

$$E_{kpy,i} = (E_i \times OpHrs) \quad (5)$$

where:

$E_{kpy,i}$ = annual emissions in kg/year of pollutant i
E_i = hourly emissions in kg/hr of pollutant i
OpHrs = annual operating hours in hr/yr

Emissions in kilograms of pollutant per tonne of fuel consumed can be calculated by dividing the emission rate in kg/hr, by the fuel consumption rate (tonnes/hr) during the same period (Equation (6)) as shown below. It should be noted that the emission factor calculated below assumes that the selected time period (that is, hourly) is representative of annual operating conditions, and longer time periods should be used for NPI reporting where they are available. Use of the calculation is shown in Example 2.

$$(E_{kpt,i})_1 = E_i / AR_{hr} \quad (6)$$

where:

$(E_{kpt,i})_{1\ 0}$ = emissions of pollutant i per tonne of fuel oil consumed, kg/tonne
E_i = hourly emissions of pollutant i, kg/hr
AR_{hr} = fuel oil consumption, tonnes/hr

Example 2 Estimating sulfur dioxide emissions using CEMS data

This example shows how SO_2 emissions can be calculated using Equation (4) based on the average CEMS data for Time Period 1 shown in the Table 4.

E_{SO2} = (C x MW x Q x 3 600) / (V x 1.0E+06)
C = 150.9 ppmv
MW = 64
Q = 8.52 $m^3_{stp,dry}$/s
V = 22.4 m^3/kg-mole

E_{SO2} = (150.9 x 64 x 8.52 x 3 600) / (22.4E+06)
= 296 217 907 / 22 400 000
= 13.22kg/hr

For time Period 2
E_{SO2} = 12.56 kg/hr

For time Period 3
E_{SO2} = 11.2 kg/hr

Say representative operating conditions for the year are:
Period 1 = 1500 hr
Period 2 = 2000 hr
Period 3 = 1800 hr

Total emissions for the year = (13.22 x 1500) + (12.56 x 2000) +(11.2 x 1800) kg
$E_{kpy,SO2}$ = 65 110 kg/yr

Emissions, in terms of kg/tonne of oil consumed for time period 1, are calculated using Equation (6):

$E_{kpt,SO2}$ = E_{SO2} / AR_{hr}
= 13.22 / 290
= 4.56E-02 kg SO_2 emitted per tonne of fuel oil consumed

Similar calculations could be undertaken for the other time periods.

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

6.3 Using Fuel Analysis Data

Fuel analysis can be used to predict SO_2, metals and metal compounds, and other emissions based on application of mass conservation laws.

It is important if using fuel analysis data to ensure that data are collected and reported in an approved and consistent manner from representative fuel samples. Standards Australia AS 1038 Coal and Coke – Analysis and Testing (Reference: Standards Australia 2002) provides a useful guide to sampling and analysing coal and coke.

AS 1038 includes recommended procedures for the analysis of trace elements in coal and ash samples. Also included are required detection and precision limits. It is recommended that this document and its future drafts be referenced by facilities undertaking coal and or ash analysis.

Should relevant, recent coal concentration data not be available facilities have the option of using data in Table 20 and Table 21 of the Manual to obtain default concentration data. Data for some elements are presented as a concentration range in these tables. **If data from these tables is used in preference to current, facility-specific data, the upper end of the concentration range in the tables should be used.**

EETs in tables in following sections are generally presented as either:

- kg/tonne – kilograms emitted per tonne of coal burnt on an "as received" basis. Attention should be paid to ensuring that coal data, including trace element concentration data, are reported on an as received basis. If reported on some other basis, such as dry ash free, moisture and ash characteristics should be obtained to enable conversion to an as received basis; or

- kg/PJ – kilograms emitted per petajoule of coal burnt on a higher heating value (HHV) basis.

The presence of certain elements in fuels may be used to predict their presence in emission streams. This includes elements such as sulfur, that may be converted into other compounds during the combustion process.

The basic equation used in fuel analysis emission calculations is the following:

$$E_{kpy,i} = Q_f \times C \times (MW_p / EW_f) \times 1E\text{-}06 \times OpHrs \qquad (7)$$

where:

$E_{kpy,i}$ = emissions of pollutant i, kg/yr
Q_f = fuel use (kg/hr)
C = pollutant concentration in fuel – ppm or mg/kg
MW_p = molecular weight of pollutant emitted (kg/kg-mole)
EW_f = elemental weight of pollutant in fuel (kg/kg-mole)
$OpHrs$ = annual operating hours in hr/yr

For instance, sulfur dioxide emissions from oil combustion can be calculated based on the concentration of sulfur in the oil. This approach assumes complete conversion of sulfur to sulfur dioxide. Therefore, for every kilogram of sulfur (EW = 32) burned, two kilograms of SO_2 (MW = 64) are emitted. The application of this EET is shown in Example 3.

Example 3 Estimating sulfur dioxide emissions using fuel analysis data

This example shows how SO_2 emissions can be calculated from oil combustion, based on fuel analysis results, and the fuel use information. The power station is assumed to operate 150 hours per year on oil and the sulfur content of the oil is 1.17% (11,700 ppm).

$E_{kpy,SO2}$ can be calculated using Equation (7)

Assume:

Q_f = 2 000 kg/hr
C = 17 700 ppm
OpHrs = 150 hr/yr

$E_{kpy,SO2}$ = Q_f x C x (MW_p / EW_f) x 1.0E-06 x OpHrs
= (2,000) x 11 700 x (64 / 32) x 1E-06 kg/hr x OpHrs
= 46.8 kg/hr x 150 hr/yr
= 7.0E+03 kg/year

Note:

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Equation 7 is based on the assumption that the pollutant in the fuel is emitted to atmosphere and is therefore most appropriate for volatile elements in coal, such as sulfur, fluorine and chlorine. For elements that are captured effectively, either in bottom ash or fly ash (i.e. most metals with the possible exception of mercury) equation 7 can result in overestimation of emissions. If coal concentrations and ash fractions are known, emission estimates may be able to be calculated without stack measurements by utilising mass balance techniques. See Section 5.4 for a discussion of the mass balance technique.

Fuel analysis data can also be used in emission factors and equations – See Sections 5.5 and 5.6 for discussion of these EETs.

6.4 Using a mass balance approach – Trace element behaviour during combustion

Trace elements have been classified into 3 general, overlapping classes according to their behaviour during combustion. To assist in estimating emissions of some elements, the following information on behaviour during combustion is relevant. The following summarises the characteristics of the three classes (Clarke and Sloss 1992).

Class I: Elements which are concentrated in the coarse residues (bottom ash) or are partitioned equally between coarse residues and flyash which is generally trapped by the particulate control systems.

Class II: Elements concentrated more in the flyash compared with coarse residues. Also enriched in fine-grained particles that may escape the particle control systems.

Class III: Elements which volatilise most readily. They may be concentrated in the vapour phase and depleted in the solid phases.

The NPI substances boron & compounds, mercury & compounds, fluorine compounds, chlorine and selenium & compounds may be emitted substantially in the gas phase, that is these five substances generally fall into Class III or are intermediate between Classes II and III. For these substances it may be worth analysing ash as well as coal samples to enable emissions to be determined via mass balance approach.

NPI substances such as mercury & compounds may be able to be determined by examining the mercury levels in the coal and ash. The mass balance approach requires the collection of reliable, representative data on element concentrations in coal and ash. It assumes that the difference between the quantity of the element measured in coal and collected in ash is emitted to the atmosphere. It is understood that this method is used by some American utilities in reporting mercury emissions to the USEPA Toxics Release Inventory (the US program similar to the NPI).

$$E_{kg/tonne} = \{C - [(A \times F \times CF) + (A \times B \times CB)]\} \times 1E\text{-}03 \tag{8}$$

Where:
E = emission of substance to air (kg/tonne)
C = concentration of element (substance) in coal (ppm or mg/kg)
A = weight fraction of ash in coal (as received)
F = fly ash fraction of total ash
B = bottom ash fraction of total ash
CF = fly ash concentration of element (substance) (ppm or mg/kg)
CB = bottom ash concentration of element (substance) (ppm or mg/kg)

Where possible, attempts should be made to ensure that the ash and coal samples analysed are derived from the source coal.

The approach could be simplified and made more conservative by ignoring the small amount of these elements that might be expected to report to bottom ash (i.e. B or CB above is zero).

Based on the reported variability in the emission of these elements, it is expected that coal and ash samples could also show considerable variability. If a mass balance approach were to be pursued, it is recommended that at least 6 coal and ash samples initially be collected and analysed for a statistically meaningful relationship.

Example 4 shows an example of the use of Equation 8.

Example 4 Estimating fluoride compounds emissions based on fluoride levels in coal and ash

This example shows how fluoride compounds emissions can be calculated using a mass balance approach.

$$E_{kg/tonne\ HF} = \{C - [(A \times F \times CF) + (A \times B \times CB)]\} \times 1E\text{-}03$$

Where: C = 250 mg fluoride / kg of coal
A = 0.20
F = 0.9
CF = 500 mg fluoride /kg of coal
B = 0.1
CB = 50 mg/kg of bottom ash

$$E_{kg/tonneHF} = \{250 - [(0.20 \times 0.9 \times 500) + (0.2 \times 0.1 \times 50)]\} \times 1E\text{-}03$$

$$E_{kg/tonneHF} = \{250 - (90 + 1)\} \times 1E\text{-}03$$

$$E_{kg/tonneHF} = 0.159 \text{ kg/tonne}$$

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

6.5 Emission Factors

Emission factors usually relate the quantity of substances emitted from a source to some common activity associated with those emissions. Emission factors are obtained from US, European and Australian sources, and are usually expressed as the weight of a substance emitted for a unit mass, volume, distance, or duration of the activity emitting the substance (e.g. kilograms of sulfur dioxide emitted per tonne of coal fired).

When available, it is preferable to use facility-specific information (e.g. monitoring data) for emission estimation.

Emission factors are used to estimate a facility's emissions by the general equation:

$$E_{kpy,i} = AR \times EF_i \times [1 - (CE_i/100)] \qquad (9)$$

where :

$E_{kpy,i}$ = emission rate of pollutant i, kg/yr
AR = activity rate (fuel use), t/yr (AR = t/hr x Ophrs)
$Ophrs$ = operating hours, hr/yr
EF_i = uncontrolled emission factor of pollutant i, kg/t
CE_i = overall control efficiency for pollutant i, %.

Emission factors are based on either fuel consumption (kg/tonne of fuel consumed), or energy consumption (kg/PJ or tonne/PJ of energy input). Where the emission factor is based on energy consumption, use:

Energy consumption (PJ/year) = [fuel consumption (tonnes/year) x higher heating value (MJ/kg)]/10^6

Emission factors developed from measurements for a specific power station or process can sometimes be used to estimate emissions at other sites. If a company has several processes of similar operation and size, and emissions are measured from one process source, an emission factor can be developed and applied to similar sources. The emission factor must be approved by State or Territory environmental authorities prior to its use for NPI estimations.

Emission factors are commonly available for emissions to air, but currently are rarely available for emissions to water or land.

Many of the emission factors are derived from the *Compilation of Air Emission Factors, AP-42, Fifth Edition, Volume 1: Stationary Point and Area Sources* (Reference: USEPA 1995). Sections within AP-42 are updated at different times and hence the references to AP-42 may vary in date. The version adopted for this manual was current in 2002.

A discussion of the rating of emissions factors is contained in section 5 of this manual.

There are currently no emission factors for emissions to land. It is recommended that other EETs, particularly direct measurement and mass balance, be applied to these emissions.

6.6 Using Engineering Calculations

There are engineering equations available to enable emissions of a number of trace metals and metal compounds, from black and brown coal combustion, to be estimated with a high degree of confidence. The advantage of these emission equations over simple generic emission factors is that they require the input of facility-specific information relating to fuel type and operating conditions.

The form of the emission equations is shown in Equation 10

$$E_{kg/PJ} = K \times [(C/A) \times PM]^e \text{ kg/PJ.} \qquad (10)$$

Where:

$E_{kg/PJ}$ = emission factor for substance

K = a constant

C = concentration of metal in the coal, part per million by mass (as received basis)

A = weight fraction of ash in the coal. (10% ash is 0.1 ash fraction)

e = an exponent

PM = facility-specific emission factor for total particulate matter (kg/GJ) i.e. particulate matter emitted per GJ heat input.

$$PM \text{ (kg/GJ)} = A \times F \times ER \times 1000/SE \qquad (11)$$

Where:

A = weight fraction of ash in coal

F = fly ash fraction of total ash

ER = fraction of flyash emitted
= (1 –CE/100) where CE = particulate collection efficiency as %

SE = specific energy GJ/tonne as received

The application of these equations is demonstrated in example 5.

Example 5 Engineering calculations to estimate cadmium & compounds emissions from coal combustion

This example shows how cadmium & compounds emissions can be calculated using the relevant emission equation.

$E_{kg/PJ\ Cd}$ = $2.17 \times [(C/A) \times PM]^{0.5}$

Where:
C = 0.5 mg/kg
A = 0.2 (20% ash)
F = 0.9 (90% flyash)
CE = 99.8% (default for fabric filters)
ER = 1- 99.8/100
= 0.002
SE = 24 GJ/tonne

PM = $0.2 \times 0.9 \times 0.002 \times 1000 / 24$
= 0.015 kg/GJ

$E_{kg/PJ\ Cd}$ = $2.17 \times [(0.5/0.2) \times 0.015]^{0.5}$

= 0.42 kg cadmium & compounds/PJ

Should relevant, recent coal concentration data not be available facilities can use default concentration data from Table 20 and Table 21. Data for some elements are presented as a concentration range in these tables. **If data from these tables is used in preference to current, facility-specific data, the upper end of the concentration range should be used.**

7 Emission Factors and Equations

Section 7 contains emission factors and equations for the estimation of NPI substances from electricity production. The list of tables below show the location of various emission factors and equation for different types of fossil fuel powered electricity generation processes. Emission factors are one of the techniques that can used to estimate emissions for the NPI.

The emission factors are applied as per the units of each factor and notes in the table. The equations from tables 5 to 18 are described in section 6.4 of this manual. Some of the emission factors are derived from equations.

Table 5:	Emission Estimation Techniques for Black Coal Combustion
Table 6:	Specific Power Station Nitrogen Oxide Emission Factors for Black Coal Combustion
Table 7:	Emission Estimation Techniques for Brown Coal Combustion
Table 8:	Emission Estimation Techniques for Victorian Brown Coal Combustion
Table 9	Power Station Specific Emission Factors for Brown Coal Combustion (NO_X, CO)
Table 10:	Emission Estimation Techniques for Natural Gas Combustion – Steam cycle
Table 11:	Facility-Specific Emission Factors for Natural Gas Combustion (NO_X, CO, and TVOCs)
Table 12:	Emission Estimation Techniques for Oil (fuel oil and distillate) Combustion
Table 13:	Emission Factors for LPG Combustion (SO_2, NO_X, CO, and PM_{10})
Table 14:	Emission Estimation Techniques for Combustion in a Stationary Gas Turbine Gas or Distillate
Table 15:	Specific Power Station Emission Factors for Gas Turbines (NO_X, CO, and TVOCs)
Table 16:	Emission Estimation Techniques for Combustion in Combustion Engines- Oil and Natural Gas
Table 17:	Solvent Emission Factors
Table 18:	Indicative trigger volumes for organic substances and lead.

In the Appendices, Table 19 indicates the NPI listed substances that are relevant to the fossil fuel electric power generation industry. Table 20 and Table 21 contain information on coal properties that may be useful for applying the equations to estimate emissions.

7.1 Emission Factors for Black Coal Combustion (Steam Cycle)

Tables 5 to 18 include emission factors for NPI pollutant emissions to air for the combustion of black coal in boilers for electricity generation. Black coal includes bituminous and sub-bituminous coals. For this application, bituminous coals generally have volatile matter (VM) 14% or more dry, ash free (daf), and heating values (gross specific energy) 26.5 MJ/kg ash-free, moist (afm) or more (24.0 MJ/kg or more provided that the crucible swelling number is 1 or less). For sub-bituminous coals, the heating value range is 19 MJ/kg to 23.98 MJ/kg (afm) inclusive, or to 26.48 MJ/kg (daf) inclusive, provided that the crucible swelling number is zero or half (Reference: Standards Association of Australia 1987).

For a number of substances, equations to determine emissions factors are provided as well as generic emission factors. Where a facility has available facility-specific coal, coal ash data (such as coal ash levels (A) and concentration of the substance in coal (C)) and particulate collection efficiency data, these equations could be used instead of the simpler generic emission factors. Table 5 includes equations for antimony & compounds, arsenic & compounds, beryllium & compounds, boron & compounds, cadmium & compounds, chromium (III) compounds, chromium (VI) compounds, cobalt & compounds, copper & compounds, lead & compounds, manganese & compounds, mercury & compounds, nickel & compounds, PM_{10}, sulfuric acid, and zinc & compounds.

For a number of substances, including boron & compounds, hydrogen fluoride, hydrochloric acid and mercury & compounds it is considered that a simple mass balance approach may yield reliable emission estimates (See Section 5.4).

Facility-specific emission factors for NO_X are given in Table 6. For a number of other substances it is expected that facilities may have facility-specific estimation techniques, which could be used in preference to the EETs presented in Table 5, as long as these facility-specific techniques have been approved by the environmental authority in the jurisdiction where the facility is located.

Example 6 shows how to estimate sulfur dioxide emission factor based on the sulfur level in coal.

Table 5 Emission Factors for Black Coal Combustion

Substance	**Threshold category**	**Emission Estimation Technique (a)** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/tonne unless otherwise indicated**	**EFR (b)**
Ammonia	1	2.8E-04 (**6.0**)	U
Antimony & compounds	1	0.675 x [(C/A) x PM] $^{0.63}$ kg/PJ (**6.1**) 9E-06 (**l**)	A
Arsenic &compounds	1/2b	2.73 x [(C/A) x PM] $^{0.85}$ kg/PJ (**6.2**) 2.1E-04 (**l**)	A
Benzene	1	3.4 kg/PJ (**6.3**)	U
Beryllium & compounds	1/2b	1.31 x [(C/A) x PM] $^{1.1}$ kg/PJ (**6.4**) 1.1E-05 (**l**)	A
Boron & compounds	1	C x 1E-03 x 0.5 (**c**) (**6.5**)	U
Cadmium & compounds	1/2b	2.17 x [(C/A) x PM] $^{0.5}$ kg/PJ (**6.6**) 2.6E-05 (**l**)	A
Carbon monoxide	1/2a	2.5E-01 (**6.7**)	A
Chromium (III) compounds	1/2b	0.95x2.6x[(C/A)xPM] $^{0.58}$ kg/PJ (**c**) (**6.8**) 1.3E-04	A
Chromium (VI) compounds	1/2b	0.05 x 2.6 x [(C/A) x PM]$^{0.58}$ kg/PJ (**c**)(**6.8**) 9.0E-05 (**l**)	A
Cobalt & compounds	1	1.31 x [(C/A) x PM] $^{0.69}$ kg/PJ (**6.9**) 5E-05 (**l**)	A
Copper & compounds	1/2b	1.31 x [(C/A) x PM]$^{1.1}$ kg/PJ (**6.10**)	U
Cumene	1	2.7E-06 (**6.11**)	U
Cyanide (inorganic) compounds	1	1.3E-03 (**6.12**)	D
Cyclohexane	1	3.4E-05 (**6.13**)	
Ethylbenzene	1	4.7E-05 (**14**)	U
Fluoride compounds	1/2b	7.5E-02 (**6.15**)	B
n-Hexane	1	3.4E-05 (**6.16**)	U
Hydrochloric acid	1/2a	0.6 (**6.17**)	B
Lead & compounds	1/2b	2.87 x [(C/A) x PM] $^{0.8}$ kg/PJ (**6.18**) 2.1E-04 (**l**)	A
Magnesium oxide fume	1/2b	0 (**6.19**)	U
Manganese & compounds	1	2.71 x [(C/A) x PM] $^{0.6}$ kg/PJ (**6.20**) 2.5E-04 (**l**)	A
Mercury & compounds	1/2b	C x 1.7 E-04 for fabric filter plant and C x 5.4 E-04 for Electrostatic Precipitator (ESP) plant (**d**) (**6.21**) 4.2E-05 (**l**)	A
Nickel & compounds	1/2b	2.84 x [(C/A) x PM] $^{0.48}$ kg/PJ (**6.22**) 1.4E-04 (**l**)	A
Nickel carbonyl	1/2b	0 Not emitted during electricity generation by combustion (**e**) (**6.23**)	U
Nickel subsulfide	1/2b	0 Not emitted during electricity generation by combustion (**e**) (**6.23**)	U

Substance	Threshold category	Emission Estimation Technique (a) (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (b)
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2) (**f**)	1/2a	11.0 Uncontrolled, dry bottom, wall fired, bituminous 5.5 Low NOx burner, dry bottom, wall fired, bituminous 6.0 Uncontrolled, dry bottom, wall fired, sub-bituminous 6.0 Dry bottom, wall fired. Post 1978 (**f**) 3.7 Dry bottom, wall fired, sub-bituminous. Post 1978 (**f**) 7.5 Uncontrolled, dry bottom, tangentially fired, bituminous 4.9 Low NOx burner, dry bottom, tangentially fired, bituminous 4.2 Uncontrolled, dry bottom, wall fired, sub-bituminous 3.6 Dry bottom, wall fired, sub-bituminous. Post 1978 (**f**) 15.5 Uncontrolled, wet bottom, wall fired, bituminous 7.0 Wet bottom, tangentially fired, bituminous. Post 1978 (**f**) 12.0 Wet bottom, wall fired, sub-bituminous 16.5 Cyclone furnace, bituminous 8.5 Cyclone furnace, sub-bituminous 2.5 Fluidised bed, circulating 7.6 Fluidised bed, bubbling (**6.24**) See also Table 6	A A A A A A A A D E E A C D D
PM_{10}	1/2a	A x 1000 x F x (1-ER/100) x FP (**c**) (**6.25**) 0.34 for fabric filter plant 0.96 for ESP plant	A
Polychlorinated dioxin & furans (**g**)	2b	8.8E-10	D
Polycyclic aromatic hydrocarbons (**i**)	2a	1.0E-05 (**6.27**)	B-D
Selenium & compounds	1	6.5E-04 (**6.28**)	A
Sulfur dioxide	1/2a	19 x S Bituminous coal 17.5 x S. Subbituminous coal (**6.29**)	A
Sulfuric acid	1	0.2 x S (**j**) (**6.30**)	U
Toluene (methylbenzene)	1	1.2E-04 (**6.31**)	U
TVOCs (**k**)	1a/2a	3E-02 dry bottom boilers, wall and tangentially fired 2E-02 wet bottom boilers 6.0E-01 cyclone furnace (**6.32**)	B
Xylenes	1	1.9E-05 (**6.33**)	U
Zinc and compounds	1	2.84 x $[(C/A) \times PM]^{0.48}$ kg/PJ (**6.34**)	U

Notes:

*Derived from Reference: USEPA 1998a (*unless otherwise stated).

a. Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators, or fabric filters

b. Emission Factor Rating (see Section 5)

c. Pacific Power International 2002

d. USEPA 2001

e. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

f. Refer to Table 1.1-3 AP-42 (Reference: USEPA 1998a) for explanation and additional factors, if required. Post 1978 refer to boilers which, after this date, were required to meet the US New Source Performance Standards (NSPS)

g. Reference: USEPA AP-42, 1998a, lists the following as constituents of total PCDD/PCDF: total TCDD, total PeCDD, total HxCDD, total HpCDD, total OCDD, total TCDF, total PeCDF, total HxCDF, total HpCDF and total OCDF

h. Reference: UNEP 2001

Substance	Threshold category	**Emission Estimation Technique (a)** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/tonne unless otherwise indicated**	EFR (b)

i. Polycyclic Aromatic Hydrocarbons (PAHs) listed in AP-42 (Reference: USEPA 1998a) include: biphenyl, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(b,j,k)fluoranthene, benzo(g,h,i)perylene, chrysene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene, 5-methyl chrysene. It should be noted that this list is similar, but slightly different, to the NPI list of PAHs

j. Reference: USEPA 1998a

k. Total non-methane organic compounds from AP-42 (Reference: USEPA 1998a). Similar but slightly different from the NPI TVOCs definition

l. Factors based on coal feed, as fired, and apply to controlled coal combustion for boilers utilising electrostatic precipitators or fabric filters

C = concentration of metal in the coal, part per million by mass or mg/kg (as received basis)

A = weight fraction of ash in the coal. (10% ash is 0.1 ash fraction). Use 0.2 as default

F = flyash fraction of total ash. Assume 0.9 as default

ER = emission reduction efficiency (%). Defaults 99.8% for fabric filters and 99.2% for ESP

FP = PM_{10} fraction of emitted particles on a mass basis. Use 0.67 and 0.92 for ESP and fabric filters as default values respectively.

PM = facility-specific emission factor for total particulate matter (kg/GJ) i.e. particulate matter emitted per GJ heat input (See example 5)
S = percentage sulfur content of coal as fired (If sulfur content = 0.5%, S= 0.5)

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Example 6 Estimating sulfur dioxide emissions using emission factors

A power station with wall firing boilers uses 2 million tonnes per year of sub-bituminous coal. Estimate the annual emission of sulfur dioxide if the coal sulfur content is 0.5% (as fired). There is no sulfur reduction control.

Using Equation 9

$E_{kpy,i} = AR \times EF \times [1 - (CE_i/100)]$

$E_{kpy,SO2}$ = emission of SO_2
CE_i = 0
AR = 2E+06 tonnes
EF = 17.5S kg/tonne (from Table 5)
S = 0.5%
Therefore,

Ekpy,i = 2E+06 x 17.5 x 0.5 x [1 - 0/100] kg/year
= 1.75E+07 kg/year

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10-2 or 0.0738.

The facility-specific emission factors included in Table 6 are based on energy input (fuel consumption by higher heating value).

Table 6 Facility-Specific Emission Factors for Oxides of Nitrogen Emissions from Black Coal Combustion

POWER STATION	Emission Factor (kg/PJ)
NSW - Bayswater	2.20E+05
NSW - Eraring	2.20E+05
NSW - Mt Piper	2.20E+05
NSW - Liddell	2.60E+05
NSW - Munmorah	2.60E+05
NSW - Vales Point	2.60E+05
NSW - Wallerawang	2.60E+05
Queensland - Callide	5.23E+05
Queensland - Collinville	5.23E+05
Queensland - Gladstone	5.23E+05
Queensland - Stanwell	5.23E+05
Queensland - Swanbank	5.23E+05
Queensland - Tarong	5.23E+05
Western Australia - Muja A/B	4.62E+05

POWER STATION	Emission Factor (kg/PJ)
Western Australia - Muja C/D	3.06E+05
Western Australia - Collie	3.24E+05
Western Australia - Kwinana A	4.62E+05
Western Australia - Kwinana C	3.06E+05

Notes:

1. Reference: Department of the Environment, Sport and Territories 1996
2. Oxides of nitrogen expressed as nitrogen dioxide (NO_2)
3. Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Example 7 Determining oxides of nitrogen emissions for a power station using an emission factor

Determine the annual NO_X emissions for a power station with the same emission factor as Bayswater Power Station (operates 5,000 hours per year), with an emission factor of 220 tonne/PJ. Fuel higher heating value is 24 MJ/kg and fuel consumption is 50 tonnes/hour.

EFuel input (PJ/year) = [fuel usage (tonnes/year) x higher heating value (MJ/kg)]/10^6
= [50 (tonnes/hr) x 5000 (hr) x 24 MJ/kg)]/10^6
= 6.0 PJ/year

NO_X emissions ($E_{kpy,NOx}$) = AR x EF x [1 - (CE_i/100)] (Equation 9)

AR = Activity (energy input)
= 6.0 PJ/year
CE_i = 0
$E_{kpy,NOx}$ = 6.0 (PJ/year) x 220 (tonne/PJ) x 10^3 kg/year
= 1.32E+06 kg/year

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

7.2 Emission Factors for Brown Coal Combustion (Steam Cycle)

Brown coal or lignite is a low rank coal used for electricity generation in Victoria and South Australia. Brown coal usually has a high moisture content and low heating value (<19 MJ/kg (afm)). A small quantity of Victorian brown coal is converted into briquettes with low moisture content. Brown coal based briquettes are used as auxiliary fuel in some Victorian power stations. (afm: ash free, moist) (Reference: Standards Association of Australia 1987).

Tables 7 and 8 contain generic emission factors sourced from AP-42 for lignite and in some cases for black (bituminous and sub-bituminous) coal.

Where emission factors are derived from AP-42 factors for combustion of lignite, it is suggested that the factors be adjusted for Australian conditions, as shown in Equation 12. This is primarily because AP-42 factors are derived from tests from a number of facilities burning black coal and lignite. US lignite has moisture content of 20 – 40%, compared with ~ 40 - 60% for Victorian brown coal and ~28% for South Australian coal. Further, it should be recognised that fuel concentrations of relevant elements are likely to differ between Australian and US coals, making the emission factors less reliable than EETs based on local coal data, as discussed later in this section.

Adjustments to the AP-42 derived factors expressed as kg/tonne could be made. This includes factors for the following substances: PAH, polychlorinated dioxins and furans, trace metals, hydrochloric acid, hydrogen fluoride and category one organic substances.

Assuming that the AP-42 factors are based on coal with an average moisture content of 15%, Equation 12 describes how the AP-42 emission factors can be modified according to local moisture content.

$$\text{Revised factor} = \text{existing factor} \times ((100 - M1)/(100 - 15)) \qquad (12)$$

Where:

$M1$ = local moisture content (%)

For some substances in Tables 7 and 8 equations can be used to derive the emission factors and are given as well as generic emission factors. Where a facility has available facility-specific coal concentration, coal ash fraction and particulate collection efficiency data, these detailed emission equations could be used instead of the simpler generic emission factors. Tables 7 and 8 includes emission factor equations for antimony, arsenic & compounds, beryllium & compounds, boron & compounds, cadmium & compounds, chromium (III) compounds, chromium (VI) compounds, cobalt & compounds, copper & compounds, lead & compounds, manganese & compounds, mercury & compounds, nickel & compounds, PM_{10}, sulfuric acid, and zinc & compounds. These equations are the same as those recommended for black coal combustion, are based on AP-42 (Reference: USEPA 1998a) and require coal concentration, ash fraction and particulate collection efficiency data. As the equations are based on energy input they are applicable to all coal types, as noted in AP-42.

For a number of substances, including boron & compounds, hydrogen fluoride, hydrochloric acid and mercury & compounds it is considered that a simple mass balance approach could yield reliable emission estimates (See Section 6.4).

Table 8 contains emission factors specific to the combustion of Victorian brown coal. The factors are based on emission testing undertaken at the Victorian power stations, in the Latrobe Valley and at Anglesea, over a 3-year period. These factors are reported as emissions per tonne of fuel burnt (as received). The development of the emission factors involved a number of stack sampling tests in accordance with USEPA published methods described in Reference: Pacific Power International 2002.

These factors should only be used following approval by the relevant environmental authority. Where Table 8 does not include an emission factor, facilities should use Table 7.

Facility-specific emission factors for NOx and carbon monoxide are given in Table 9. For a number of other substances it is expected that facilities may have facility-specific estimation techniques, which could be used in preference to the EETs presented in Table 7, as long as these facility-specific techniques have been endorsed by the appropriate environmental authority.

Table 7 Emission Factors for Brown Coal Combustion

Substance	**Threshold category**	**Emission Estimation Technique** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/tonne unless otherwise indicated**	**EFR (a)**
Ammonia	1	1.3E-03 (**b**) (**6.37**)	U
Antimony & compounds	1	0.675 x [(C/A) x PM]$^{0.63}$ kg/PJ 1.75 E-06 (**c**) (**e**) (**6.1**)	A A
Arsenic &compounds	1/2b	2.73 x [(C/A) x PM]$^{0.85}$ kg/PJ 3.0E-06 (**c**) (**e**) (**6.2)**	A A
Benzene	1	3.6 E-06	A
Beryllium & compounds	1/2b	1.31 x [(C/A) x PM]$^{1.1}$ kg/PJ 1.7E-06 (**c**) (**e**) (**6.4)**	A A
Boron & compounds	1	C x 1E-03 x 0.5 (**b**) (**6.5**) 6.2E-03	U
Cadmium & compounds	1/2b	2.17 x [(C/A) x PM]$^{0.5}$ kg/PJ 2.5 E-06 (**c**) (**e**) (**6.6**)	A A
Carbon monoxide	1/2a	0.13 wall fired uncontrolled combustion **(d)** 0.24 wall fired, overfire air, Low NOx burners 0.05 tangentially fired, overfire air 0.08 atmospheric fluidised bed See also Table 9 (**6.7**)	C D D
Chromium (III) compounds	1/2b	0.95 x 2.6 x [(C/A) x PM] $^{0.58}$ kg/PJ (**b**) 9.0E-06 (**c**) (**e**) (**6.8**)	A A
Chromium (VI) compounds	1/2b	0.05 x 2.6 x [(C/A) x PM]$^{0.58}$ kg/PJ (**b**) 6.1E-06 (**c**) (**e**) (**6.8**)	A D
Cobalt & compounds	1	1.31 x [(C/A) x PM]$^{0.69}$ kg/PJ 2.7E-06 (**c**) (**e**) (**6.9**)	A A
Copper & compounds	1/2b	1.31x [(C/A) x PM]$^{1.1}$ kg/PJ (**6.10**) 6.2E-06	U
Cumene	1	5.8E-08 **(6.12 & 6.36)**	U
Cyanide (inorganic) compounds	1	3.6E-06 **(6.36)**	D
Cyclohexane	1	3.6E-06 **(6.13 & 6.36)**	U
Ethylbenzene	1	3.6E-06 **(6.14 & 6.36)**	U
Fluoride compounds (as hydrogen fluoride)	1/2b	3.5E-02 (from a mass balance) **(6.15)**	B
n-Hexane	1	3.6E-06 **(6.16 & 6.36)**	U
Hydrochloric acid	1/2a	4.6E-01 (from a mass balance) **(6.17 & 6.36)**	B
Lead & compounds	1/2b	2.87 x [(C/A) x PM]$^{0.8}$ kg/PJ 8.1E-06 **(6.36)**	A A
Magnesium oxide fume	1/2b	0 **(6.19)**	
Manganese & compounds	1	2.71 x [(C/A) x PM]$^{0.6}$ kg/PJ 2.1E-04 **(6.36)**	A A
Mercury & compounds	1/2b	C x 9.8E-04 1.6E-06 **(6.36)**	A A
Nickel & compounds	1/2b	2.84 x [(C/A) x PM]$^{0.48}$ kg/PJ 3.4E-05 **(6.36)**	A A

Substance	**Threshold category**	**Emission Estimation Technique** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/tonne unless otherwise indicated**	**EFR (a)**
Nickel carbonyl	1/2b	0 Not emitted during electricity generation by combustion **(g) (6.23)**	U
Nickel subsulfide	1/2b	0 Not emitted during electricity generation by combustion **(g) (6.23)**	U
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2) (**h**)	1/2a	3.5 Dry bottom, tangentially fired 3.4 Tangentially fired, overfire air 6.5 Dry bottom wall fired. Pre 1978 (**i**) 3.2 Dry bottom, wall fired. Post 1978 (**i**) 2.3 Wall fired, overfire air, low NOx burners 7.5 Cyclone furnace 1.8 Atmospheric fluidised bed (**6.24**) Refer also to Table 9.	C C C C C
PM_{10}	1/2a	A x 1000 x F x (1-ER/100) x FP (**b**) (**6.25**) 1.7 x A for fabric filter 4.8 x A for ESP	A
Polychlorinated dioxin & furans (**j**)	2b	8.8 E-10(**f**) (**6.26**)	U D
Polycyclic aromatic hydrocarbons (**l**)	2a	8.0 E-07 (**e**) (**6.27**)	B-D
Selenium & compounds	1	7.8 E-06 (**c**) (**e**) 0.7 kg/PJ **(6.28 & 6.36)**	A
Sulfur dioxide	1/2a	15 x S 5 x S (fluidised bed using limestone bed material) (**6.29**)	C C
Sulfuric acid	1	1.6 E-03 **(6.36)** 0.2 x S **(6.30)** (**m**)	U
Toluene (methylbenzene)	1	3.6 E-06 **(6.31 & 6.36)**	A
TVOCs (**n**)	1a/2a	2 E-02 wall and tangential firing 3.5 E-02 cyclone furnace 1.5 E-02 fluidised bed (**6.32**)	C C C
Xylenes	1	3.6 E-06 **(6.33 & 6.36)**	C
Zinc and compounds	1	7.4 E-05 **(6.36)** 2.84 x $[(C/A) \times PM]^{0.48}$ kg/PJ (**6.34**)	U U

Notes:

Derived from Reference: USEPA 1998a (unless otherwise stated).

a. Emission Factor Rating (see Section 5)

b. Reference: Pacific Power International 2002

c. Factors based on coal feed, as fired, and apply to controlled coal combustion for boilers utilising electrostatic precipitators or fabric filters.

d. Consider using wall-fired factor for tangentially fired boilers.

e. Based on test results from facilities firing black coal (26 facilities) and lignite (1-2 facilities). Consider adjusting for moisture differences using Equation 12, with M1 =15

f. Reference: USEPA 2001

g. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

h. Refer to Table 1.1-3 AP-42 Reference: USEPA 1998a for explanation and additional factors, if required.

i. Post 1978 refer to boilers which, after this date, were required to meet the US New Source Performance Standards (NSPS)

j. AP-42 lists the following as constituents of total PCDD/PCDF: total TCDD, total PeCDD, total HxCDD, total HpCDD, total OCDD, total TCDF, total PeCDF, total HxCDF, total HpCDF and total OCDF

k. Reference: UNEP 2001

l. Polycyclic Aromatic Hydrocarbons (PAHs) listed in AP-42 include: biphenyl, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene,

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (a)

benzo(b,j,k)fluoranthene,benzo(g,h,i)perylene, chrysene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene, 5-methyl chrysene. It should be noted that this list is similar, but slightly different, to the NPI list of PAHs

m. Reference: USEPA 1998a

n. Total non-methane organic compounds from AP-42 (Reference: USEPA 1998a). Similar but slightly different from the NPI TVOCs definition

C = concentration of metal in the coal, part per million by mass or mg/kg (as received basis)

A = weight fraction of ash in the coal. (10% ash is 0.1 ash fraction). See Appendix B-2 for default values for Latrobe, Anglesea and Leigh Creek coal.

F = flyash fraction of total ash. Assume 0.9 as default.

ER = emission reduction efficiency (%). Defaults 99.8 for fabric filters, 99.2 for ESP and 80 for cyclones

FP = PM_{10} fraction of emitted particles on a mass basis. Use 0.67 for ESP, 0.92 for Fabric filters and 0.67 for cyclones as default values.

PM = facility-specific emission factor for total particulate matter (kg/GJ) i.e. particulate matter emitted per GJ heat input (See example 4)

S = percentage sulfur content of coal as fired (If sulfur content = 0.5%, S= 0.5). For high sodium ash (Na2O>8%) use 11S. For low sodium ash (Na2O<2%) use 17S. If ash sodium content is unknown, use 15S.

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

Table 8 Emission Factors for Victorian Brown Coal Combustion

Substance	**Threshold category**	**Emission Estimation Technique** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/tonne unless otherwise indicated (b)**	**EFR (a)**
Ammonia	1	1.3E-03 (**6.37**) (b)	U
Antimony & compounds	1	1.7E-06 (**6.37**) (c)	U
Arsenic &compounds	1/2b	3.0E-06 (**6.37**) (c)	U
Benzene	1	3.6E-06 (**6.3**) (**6.37**) (d)	U
Beryllium & compounds	1/2b	1.7E-06 (**6.37**) (c)	U
Boron & compounds	1	6.2E-03 (**6.37**) (b)	U
Cadmium & compounds	1/2b	2.5E-06 (**6.37**) (c)	U
Carbon monoxide	1/2a	See Tables 7 & 9 (**6.7**)	
Chromium (III) compounds	1/2b	See Table 7	
Chromium (VI) compounds	1/2b	6.1E-06 (**6.37**)	U
Cobalt & compounds	1	2.7E-06 (**6.37**) (c)	U
Copper & compounds	1/2b	6.2E-06 (**6.37**)	U
Cumene	1	5.6E-08 (**6.11**) (**6.37**) (d)	U
Cyanide (inorganic) compounds	1	3.6E-06 (**6.12**) (**6.37**) (c)	U
Cyclohexane	1	3.6E-06 (**6.13**) (**6.37**) (d)	U
Dichloromethane	1	3.6E-06 (**6.37**) (d)	U
Ethylbenzene	1	3.6E-06 (**6.14**) (**6.37**) (d)	U
Fluoride compounds	1/2b	4.8E-04 (**6.37**)	B
n-Hexane	1	3.6E-06 (**6.16**) (**6.37**)	U
Hydrochloric acid	1/2a	See Table 7	
Lead & compounds	1/2b	8.1E-06 (**6.37**) (b)	U
Magnesium oxide fume	1/2b	0	
Manganese & compounds	1	2.1E-04 (**6.37**) (b)	U
Mercury & compounds	1/2b	1.6E-06 (**6.37**) (c)	U
Nickel & compounds	1/2b	3.4E-05 (**6.37**) (b)	U
Nickel carbonyl	1/2b	0 Not emitted during electricity generation by combustion (e)	
Nickel subsulfide	1/2b	0 Not emitted during electricity generation by combustion (e)	
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2)	1/2a	See Tables 7 & 9. (**6.24**)	
PM_{10}	1/2a	See Table 7	
Polychlorinated dioxin & furans	2b	See Table 7	
Polycyclic aromatic hydrocarbons	2a	8.0E-07 (**6.37**)	U
Selenium & compounds	1	7.8E-06 (**6.37**) (c)	U

Substance	**Threshold category**	**Emission Estimation Technique** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/tonne unless otherwise indicated (b)**	**EFR (a)**
Sulfur dioxide	1/2a	See Table 7	
Sulfuric acid	1	1.6E-03 (**6.37**) (b)	U
Tetrachloroethylene	1	3.6E-06 (**6.37**) (d)	U
Toluene (methylbenzene)	1	3.6E-06 (**6.31**) (**6.37**) (d)	U
TVOCs	1a/2a	See Table 7	
Trichloroethylene	1	3.6E-06 (**6.37**)	U
Xylenes	1	3.6E-06 (**6.33**) (**6.37**) (d)	U
Zinc and compounds	1	7.4E-05 (**6.37**) (c)	U

Notes:

Emission factors presented in Reference: Pacific Power International 2002, as provided by the Victorian electricity generators

a. Emission Factor Rating (see Section 5)
b. Emission factors are based on typical Australian facility measurements.
c. Emission factors are based on typical Australian facility measurements. Measured values ranged from less than detection limit to actual values. Emission factors based on the median of the range of values. Less than detection limit values were halved.
d. Emission factors are based on typical Australian facility measurements. Measured values all less than detection limit. Emission factors based on the median of half detection limit values.
e. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10-2 or 0.0738.

Example 8 Estimating sulfur dioxide emissions using an engineering calculation based on the fuel composition

Calculate the annual sulfur dioxide emission to air from a brown coal fired power station using 4 million tonnes of brown coal per year. The coal has a sulfur content of 0.8% (as fired). 10% of the sulfur is retained in the ash.

Using Equation 5

$$E_{kpy,i} = AR \times EF\, [1 - (CE_i/100)]$$

$E_{kpy,SO2}$ = emission of SO_2
CE_i = 10%
AR = 4.0E+06 tonnes/yr
EF = 15S kg/tonne (from Table 7)
S = 0.8%

Therefore,

$$E_{kpy,i} = 4.0E{+}06 \times 15 \times 0.8\, [1 - (10/100)] \text{ kg/year}$$
$$= 4.32E{+}07 \text{ kg/year}$$

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10-2 or 0.0738.

Table 9 emission factors are based on energy input.

Table 9 Power Station Specific Emission Factors for Brown Coal Combustion (NO_X, CO)

POWER STATION	EMISSION FACTOR (kg/PJ)	
	NO_X (note 3)	CO
Hazelwood, Victoria	1.51E+05	1.4E+04
Loy Yang A, Victoria	1.36E+05	1.8E+04
Loy Yang B, Victoria	1.36E+05	1.8E+04
Morwell, Victoria	1.51E+05	1.4E+04
Yallourn, Victoria	1.06E+05	2.0E+04
Northern, South Australia	1.36E+05	1.7E+04

Notes:

1. Reference: Department of the Environment, Sport and Territories 1996
2. PJ petajoule (1E+15 joule)
3. Oxides of nitrogen expressed as nitrogen dioxide (NO_2)

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

7.3 Emission Factors for Natural Gas Combustion (Steam Cycle)

The default emission factors in Table 10 are primarily derived from the Compilation of Air Emission Factors (Reference: USEPA 1998a), and hence relate to United States natural gas. Where possible, data for the facility specific natural gas supply should be used

Table 10 also has emission factors for the primary or criteria combustion pollutants (sulfur dioxide, nitrogen oxides, carbon monoxide, PM_{10} and TVOCs), which, in some cases, have been updated since the Manual was first published. In addition, Table 10 includes emission factors for a number of Category 1 organic substances: benzene, formaldehyde, toluene and n-Hexane. The use or emission of these substances may not exceed the 10 tonne reporting threshold – it is estimated that at least 13PJ of gas would need to be burnt at a facility to trigger the threshold for n-hexane, which has the highest factor of the four substances. Gas burning facilities should check their fuel use to determine whether the reporting threshold for these Category 1 substances is exceeded.

Facility specific emission factors are in Table 11.

Table 10 Emission Factors for Natural Gas Combustion – Steam cycle

Substance	Threshold category	**Emission Estimation Technique** (number in brackets refers to supporting information in Reference: Pacific Power International 2002) **kg/PJ unless otherwise indicated**	EFR (a)
Ammonia	1	1.3E+02 **(6.0)**	U
Antimony & compounds	1	No data	
Arsenic &compounds	1/2b	8.5E-02	E
Benzene	1	8.8E-01	B
Beryllium & compounds	1/2b	5.1E-03 (**b**)	E
Boron & compounds	1	No data	
Cadmium & compounds	1/2b	4.6E-01	D
Carbon monoxide	1/2a	3.5E+04 Wall fired 1.0E+04 Tangential firing - uncontrolled 4.1E+04 Tangential – flue gas recirculation See also Table 11	B
Chromium (III) compounds (**c**)	1/2b	5.6E-01 (**6.8**)	D
Chromium (VI) compounds (**c**)	1/2b	3.0E-02 (**6.8**)	D
Cobalt & compounds	1	3.5E-02	D
Copper & compounds	1/2b	3.6E-01	D
Cyanide (inorganic) compounds	1	No data	
Formaldehyde	1	3.2 E+01	B
Fluoride compounds	1/2b	No data	
n-Hexane	1	7.6E+02 Note AP-42 (Reference: USEPA 1998a) factor is for hexane not n-Hexane	E
Hydrochloric acid	1/2a	No data	
Lead & compounds	1/2b	2.4E-01	D
Magnesium oxide fume	1/2b	No data (**6.19**)	
Manganese & compounds	1	1.6E-01	D
Mercury & compounds	1/2b	1.1E-01	D
Nickel & compounds	1/2b	8.8E-01	C
Nickel carbonyl	1/2b	0 Not emitted during electricity generation by combustion (**d**)(**6.23**)	U
Nickel subsulfide	1/2b	0 Not emitted during electricity generation by combustion (**d**) (**6.23**)	U
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2)	1/2a	**Large Wall fired boilers** (>100 GJ/hr heat input) 11.8E+04 Uncontrolled (**e**) 8.0E+04 Uncontrolled (**e**) 5.9E+04 Controlled - Low NOx burners 4.2E+04 Controlled – Flue gas recirculation **Small wall fired** (<100 GJ/hr heat input) 4.2E+04 Uncontrolled 2.1E+04 Controlled – Low NOx burners 1.3E+04 Controlled - Low NOx /flue gas recirc. **Tangential-fired boilers (All sizes)** 7.2E+04 Uncontrolled 3.2E+04 Controlled – Flue gas recirculation See also Table 11 (**6.24**)	 A A A D B D C A D
PM_{10} (**f**)	1/2a	3.2E+03 Uncontrolled (AP-42 Reference: USEPA 1998a)	D
Polychlorinated dioxin & furans	2b	(**g**) (**6.26**)	U
Polycyclic aromatic hydrocarbons (**b**,**h**)	2a	2.9E-01 kg/PJ(**6.27**)	E
Selenium & compounds	1	1.0E-02 (**b**)	E

Substance	**Threshold category**	**Emission Estimation Technique** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/PJ unless otherwise indicated**	**EFR (a)**
Sulfur dioxide	1/2a	2.5E+02 (**i**)	A
Sulfuric acid	1	No data (**6.30**)	
Toluene	1	1.4	C
TOCs	1a/2a	2.3E+03	C
Zinc and compounds	1	1.2E+01	E

Notes:

Reference: USEPA 1998a (Tables 1.4-1 to 1.4-4) and assuming an average higher heating value of 38 MJ/Nm^3

a. Emission Factor Rating (see Section 5)

b. Based on method detection limits

c Total chromium assumed to be 0.95% chromium(III) and 5% chromium(VI). Reference: Pacific Power International 2002

d. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

e. NSPS = New Source Performance Standard (USA). Post NSPS are boilers greater than 250 GJ/hr heat input which commenced after August 1971, and boilers between 100 and 250 GJ/hr heat input which commenced after June 1984

f. Total PM – assumes all PM$_{10}$ and included filterable and condensable fractions.

g. Reference: UNEP 2001

h. Polycyclic Aromatic Hydrocarbons (PAHs) listed in AP-42 include: biphenyl, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(b,j,k)fluoranthene,benzo(g,h,i)perylene, chrysene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene, 5-methyl chrysene. . It should be noted that this list is similar, but slightly different, to the NPI list of PAHs.

h. Derived from Table 1.4-2, AP-42 (Reference: USEPA 1998a), assuming 100% conversion of sulfur to SO$_2$, a natural gas sulfur content of 4,600 g/1E+06Nm^3 and higher heating value of 38 MJ/Nm^3

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

Table 11 Facility Specific Emission Factors for Natural Gas Combustion (NO_X, CO and TVOCs)

SUBSTANCE	EMISSION FACTOR (kg/PJ)			
	Wall-fired	**Rating**	**Tangentially fired**	**EFR (e)**
Carbon monoxide (CO)	6.0E+03 (**b**)	U	3.5E+04 (**a**)	U
	1.6E+04 (**c**)	U		
Oxides of nitrogen (NO_X expressed as nitrogen dioxide, NO_2)	1.17E+05 (**b**)	U	9.7E+04 (**a**)	U
	2.26E+05 (**c**)	U		
Total Volatile Organic Compounds (TVOCs)	6.0E+02 (**b**)	U	6.0E+02 (**a**)	U
	6.0E+02 (**c**)	U		

Notes:

Emission factors are in tonnes of emissions per PJ of heat input (based on the higher heating value)

a. for Newport Power Station, Victoria (1)
b. for Torrens Island Power Station, South Australia (1)
c. for Kwinana B Power Station, Western Australia (1)
d. Reference: Department of the Environment , Sport and Territories 1996
e. Emission Factor Rating (see Section 5)

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

7.4 Emission Factors for Oil Combustion (Steam Cycle)

Fuel oil and distillate are commonly used as auxiliary fuels in steam cycle boilers. Hence, their use is relatively minor when compared with coal and natural gas. The following tables give emission factors for fuel oil and distillate.

Table 12 Emission Factors for Oil (fuel oil and distillate) Combustion: Steam Cycle

Substance Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated					
	Fuel Oil			**Distillate**		
	kg/PJ	**kg/kL**	**EFR (a)**	**kg/PJ**	**kg/kL**	**EFR**
Ammonia	2.4E+03 **(6.0)**	9.6E-02	U	No data **(r)**	No data **(r)**	
Antimony & compounds	1.6E+01	6.3E-04	E	No data **(r)**	No data **(r)**	
Arsenic &compounds	4.0	1.6E-04	C	1.7	8.5E-05	E
Benzene	6.4E-01	2.6E-05	C	No data **(r)**	No data **(r)**	
Beryllium & compounds	8.3E-02	3.3E-06	D	1.3	5.1E-05	E
Boron & compounds	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	
Cadmium & compounds	1.2	4.8E-05	C	1.3	5.1E-05	E
Carbon monoxide (**b**)	1.5E+04	6.0E-01	A	1.5E+04	6.0E-01	A
Chromium (III) compounds	1.8 (**c**)	7.2E-05	U	9.0E-01 **(d)**	3.6E-05	U
Chromium (VI) compounds	7.4E-01	3.0E-05	C	3.9E-01 **(d)**	1.5E-05	U
Cobalt & compounds	1.8E+01	7.2E-04	D	No data **(r)**	No data **(r)**	
Copper & compounds	5.3	2.1E-04	C	2.6	1.0E-04	E
Cumene	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	

Substance Threshold category	**Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated**					
	Fuel Oil			**Distillate**		
	kg/PJ	**kg/kL**	**EFR (a)**	**kg/PJ**	**kg/kL**	**EFR**
Cyanide (inorganic) compounds	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	
Cyclohexane	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	
Ethylbenzene	1.9E-01	7.6E-06	U	No data **(r)**	No data **(r)**	
Fluoride compounds	1.1E+02	4.5E-03	D	No data **(r)**	No data **(r)**	
Formaldehyde (methyl aldehyde)	9.9E+01	4.0E-03	C	No data **(r)**	No data **(r)**	
n-Hexane	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	
Hydrochloric acid	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	
Lead & compounds	4.5	1.8E-04	C	3.9	1.5E-04	E
Magnesium oxide fume	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	
Manganese & compounds	9.0	3.6E-04	C	2.6	1.0E-04	E
Mercury & compounds	3.4E-01	1.4E-05	C	1.3	5.1E-05	E
Nickel & compounds	2.5E+02	1.0E-02	C	1.3	5.1E-05	E
Nickel carbonyl – (Not emitted during electricity generation by combustion) (**e**)	0		U	0	0	U
Nickel subsulfide – (Not emitted during electricity generation by combustion) (**e**)	0		U	0	0	U
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2) (**f**)	**Boilers > 100 GJ/hr**					
	1.4E+05 (**g**)	5.6	A			
	1.2E+05 (**h**)	4.8	B			
	9.7E+04 (**i**)	3.8	A			
	7.9E+04 (**j**)	3.1	E			
	Boilers < 100 GJ/hr					
	1.6E+05	6.6	A	6.1E+04	2.4	A
PM_{10}	1.8E+04 x A (uncontrolled)	7.1E-01 x A	C	3.0E+03	1.2E-01	E
	1.8E+02 x A **(k, l & o)**	7.1E-03 x A	E	3.0E+01	1.2E-03 **(l)**	U
Polychlorinated dioxin & furans (**m**)	9.3E-06	3.7E-10	U	8.5E-06	3.4E-10	U
Polycyclic aromatic hydrocarbons (**n**)	1.8E-01	7.3E-06	C	No data **(r)**	No data **(r)**	
Selenium & compounds	2.0	8.2E-05	C	6.5	2.6E-04	E
Sulfur dioxide	4.7E+05 x S (**o**)	1.9+01 x S	A	4.3E+05 x S (**o**)	1.7+01 x S	A
Sulfuric acid (**p**)	No data **(r)**	No data **(r)**		No data **(r)**	No data **(r)**	
Toluene (methylbenzene)	1.9E+01	7.4E-04	U	No data **(r)**	No data **(r)**	
TVOCs (**p**)	2.3E+03	9.2E-02	A	6.1E+02	2.4E-02	A
Xylenes	3.3E-01	1.3E-05	U	3.3E-01	1.3E-05	U
Zinc and compounds	8.7E+01	3.5E-03	D	1.7	6.8E-05	E

Substance Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated					
	Fuel Oil			**Distillate**		
	kg/PJ	**kg/kL**	**EFR (a)**	**kg/PJ**	**kg/kL**	**EFR**

Notes:
Reference: USEPA 1998c unless otherwise noted

Emission factors for fuel oil are those applicable to low-grade oil No 6 residual oil. Based on an energy value of 40.1 GJ/kL

a. Emission Factor Rating (see Section 5)
b. For Bell Bay use 1.5E+04 kg/PJ Reference: Department of the Environment, Sport and Territories 1996
c. Chromium (III) determined from factors for Total Chromium and Chromium. Chromium (III) = Total Cr(III + VI) – Cr(VI).
d. Chromium (III) assumed to be 0.7 x Total chromium, based on speciated results for fuel oil combustion. (Total Chromium 1.3 kg/PJ)
Chromium (VI) assumed to be 0.3 x Total chromium, based on speciated results for fuel oil combustion. (Total Chromium 1.3 kg/PJ)
e. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000
f. For Bell Bay use 1.9E+05 kg/PJ Ref. (1)
g. Normal firing
h. Normal firing with Low NO_x burners
i. Tangential firing
j. Tangential firing with Low NOx burners.
k. Particulate emission factors for residual oil combustion without emission control are, on average, a function of fuel oil grade and sulfur content. Use A = 1.12 x (S) + 0.37 (see note o. below)
l. Assuming control efficiency of 99%
m. Reference: UNEP 2001 using a TEF conversion factor of 17
n. PAHs listed in Reference: USEPA 1998a include acenaphthene, acenaphthylene, anthracene, benz(a)anthracene, benzo(b,k)fluoranthene, benzo(g,h,i)perylene, chrysene, dibenzo(a,h)anthracene, fluoranthene, fluorene, indo(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene. It should be noted that this list is similar, but slightly different, to the NPI list of PAHs
o. **S** indicates that the weight percentage of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1
p. Reference: USEPA 1998a
q. Taken as non-methane total organic compounds. For Bell Bay Power Station, Tasmania use 2.1E+03 kg/PJ Reference: Department of the Environment, Sport and Territories 1996
r. The emission factor is zero unless there is relevant information in other NPI manuals or NPI documentation, or the operators of the reporting facility are aware of other information that allows them to estimate the facility's emissions

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

7.5 Emission Factors for LPG Combustion (Steam Cycle)

Liquefied petroleum gas (LPG) (mixture of propane, butane and similar hydrocarbons) is occasionally used as an auxiliary fuel for steam cycle facility. Relevant emission factors are included below.

Table 13 Emission Factors for LPG Combustion (SO_2, NO_X, CO, and PM_{10}): Steam Cycle

SUBSTANCE	EMISSION FACTOR (kg/1000 L)[a]			
	Butane	EFR (f)	Propane	EFR (f)
Carbon monoxide (CO)	4.3E-01	E	3.8E-01	E
Oxides of nitrogen (NO_X)[c]	2.5	E	2.3	E
PM_{10}[d]	7.2E-02	E	7.2E-02	E
Sulfur dioxide (SO_2)[b]	1.9E-03 x S	E	2.1E-03 x S	E
Total Volatile Organic Compounds (TVOCs)[e]	7.2E-02	E	6.0E-02	E

Notes:
From Reference: USEPA 1995 (Table 1.5-1)

Emissions (kg/year) = [emission factor (kg/1000 L) x fuel usage (1000 L/year)]

L = Litre

a. Derived from Table 1.5-1 Reference: USEPA 1995 (Table 1.5-1) for industrial boilers
b. S equals sulfur content of gas in g/10^3 L
c. Expressed as NO_2
d. All particulate matter less than 10 µm in nominal diameter
e. Derived from Table 1.5-1 Reference: USEPA 1995 (Table 1.5-1), for total organic compounds
f. Emission Factor Rating (see Section 5)

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

7.6 Emission Factors for Stationary Gas Turbines (Natural gas and distillate fuels)

Table 14 provides emission factors for the primary or criteria combustion pollutants (sulfur dioxide, oxides of nitrogen, carbon monoxide, PM_{10} and TVOCs). Some of the factors in Table 14 have been updated since this Manual was first published.

Table 14 also includes emission factors for a number of trace elements and their compounds from diesel firing, which have recently been updated. (Reference: USEPA 1998a)

Combustion of either natural gas or distillate in gas turbines will not trigger the reporting threshold of 10 tonnes for any Category 1 substance, based on the size of existing and potential facilities. Therefore, only Category 2a/2b substances are relevant to gas turbines.

In the absence of specific emission factors for combined cycle gas turbine (CCGT) facilities, the emission factors in this section should be applied to open cycle and CCGT facilities. This is consistent with AP-42 documentation, which includes CCGT technology in the section on stationary gas turbines. Supplementary duct firing associated with a CCGT facility, if relevant, would need to be considered in addition to emissions arising from the gas turbine.

Emissions of a number of substances from gas turbines, including oxides of nitrogen and carbon monoxide, are particularly dependent upon the combustion technology employed and whether post-combustion controls are employed. The control of NO_X emissions from gas turbines is evolving rapidly, with recent advances in dry low NO_X burners capable of producing significantly lower NO_X emissions than combustion technologies of less than a decade ago.

While the review includes a number of updated, default emission factors it is recommended that facilities report NO_X and CO emissions, where possible, using information specific to the gas turbine in use.

Emission factors for gas turbines utilising exhaust gas control technology are included for the technologies listed.

- Water or steam injection where water/steam is injected into the combustion chamber(s) to reduce the flame temperature and NO_X emissions.

- Combustion control to reduce NO_X emissions through lean combustion, reduced combustor residence time, two-stage lean/lean combustion or two-stage rich/lean combustion.

NOx emissions can be further reduced by the use of Selective Catalytic Reduction (SCR) or Selective Non Catalytic Reduction (NSCR). Use of these technologies may be associated with an increase in ammonia and formaldehyde emissions. Emission factors for these substances are not included, as emissions are dependent on the technology type and degree of NO_X control achieved. Users of these technologies should ascertain their performance characteristics with respect to all relevant substances.

Table 14 includes general emission factors, whereas Table 15 contains facility-specific emission factors for NO_X, CO, and TVOCs.

Table 14 Emission Factors for Combustion in a Stationary Gas Turbine: Natural Gas and Distillate

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated				
		Natural gas		Distillate		
		kg/PJ	EFR (a)	kg/PJ	kg/kL	EFR
Arsenic &compounds **(b)**	1/2b	no data **(s)**		4.7	1.9E-04	D
Beryllium & compounds **(b)**	1/2b	no data **(s)**		1.3E-01	5.3E-06	D
Cadmium & compounds **(b)**	1/2b	no data **(s)**		2.1	8.2E-05	D
Carbon monoxide	1/2a	3.5E+04 uncontrolled 1.3E+04 water-steam injection 6.5E+03 lean premix	A A D	1.4E+03 uncontrolled 3.3E+04 water-steam injection	5.6E-02 uncontrolled 1.3 water-steam injection	C C
Chromium (III) compounds**(b)**	1/2b	no data **(s)**		3.3	1.3E-04	D
Chromium (VI) compounds **(b)**	1/2b	no data **(s)**		1.4	5.6E-05	D
Cobalt and compounds		no data **(s)**		no data **(s)**	no data **(s)**	
Copper & compounds (**b)**	1/2b	no data **(s)**		no data **(s)**	no data **(s)**	
Fluoride compounds	1/2b	no data **(s)**		no data **(s)**	no data **(s)**	
Hydrochloric acid	1/2a	no data **(s)**		no data **(s)**	no data **(s)**	
Lead & compounds (**b)**	1/2b	no data **(s)**		6.0	2.4E-04	D
Magnesium oxide fume	1/2b	0		0		
Manganese and compounds		no data **(s)**		3.4e+02	1.3E-02	
Mercury & compounds (**b**)	1/2b	no data **(s)**		5.2E-01	2.0E-05	D
Nickel & compounds **(b)**	1/2b	no data **(s)**		2.0	7.9E-05	D
Nickel carbonyl **(6.23)**	1/2b	0		0	0	
	Not emitted during electricity generation by combustion **(t)**					
Nickel subsulfide **(6.23)**	1/2b	0		0	0	
	Not emitted during electricity generation by combustion **(t)**					
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2)	1/2a	1.4E+05 uncontrolled 5.6E+04 water-steam injection 4.3+04 lean premix	A A D	3.8E+05 uncontrolled 1.0E+05 water-steam injection	1.5E+01 uncontrolled 4.1 water-steam injection	C B
PM_{10} **(b)**	1/2a	2.8E+03 uncontrolled	C	5.2E+03 uncontrolled	2.0E-01 uncontrolled	C

Substance	**Threshold category**	**Emission Estimation Technique** **(number in brackets refers to supporting information in Reference: Pacific Power International 2002)** **kg/PJ unless otherwise indicated**				
		Natural gas		**Distillate**		
		kg/PJ	**EFR (a)**	**kg/PJ**	**kg/kL**	**EFR**
Polychlorinated dioxin & furans **(j)**	2b	8.5E-06	U	8.5E-06	3.4E-10	U
Polycyclic aromatic hydrocarbons	2a	9.5E-01	C	1.7E+01	6.8E-04	C
Sulfur dioxide **(l)**	1/2a	4.1E+05 x S 2.5E+02	B	4.4E+05 x S	1.7E+01 x S	B
TVOCs **(m)**	1a/2a	9.1E+02	D	1.8E+02	7.0E-03	E

Notes:

Reference: USEPA 2000 unless otherwise noted

a. Emission Factor Rating (see Section 5)

b. Emission factors for trace and their compounds from natural gas combustion sourced from Reference: USEPA 1998a section 1.4 Natural Gas Combustion (steam cycle)

c. Compound was not detected. Emission factor based on half detection limit

d. It is recognised that the uncontrolled emission factor for CO is lower than the controlled factors, contrary to expectations. USEPA has not identified the reason for this behaviour.

e. Chromium(III) assumed to be 0.95 x Total chromium. Reference: Pacific Power International 2002

f. Chromium (VI) assumed to be 0.05 x Total chromium. Reference: Pacific Power International 2002

g. From natural gas combustion (steam cycle)

h. From distillate combustion (steam cycle)

i. Assuming a collection efficiency of 99%

j. Reference: UNEP 2001 using a TEF conversion factor of 17

k. Individual PAHS included not specified

l. All sulfur in fuel assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content is 2.5%, then S= 2.5. If S is not available use defaults (equations are more accurate).

m. TVOCs emissions are assumed to equal the sum of organic emissions.

s. The emission factor is zero unless there is relevant information in other NPI manuals or NPI documentation, or the operators of the reporting facility are aware of other information that allows them to estimate the facility's emissions

t. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

Table 15 Specific Power Station Emission Factors for Gas Turbines (NO_X, CO, and TVOCs)

Power Station	**Emission Factor (kg/PJ)**		
	CO	**NO_X (a)**	**TVOCs (b)**
Northern Territory - Channel Island,	4.6E+04	1.9E+05	2.4E+03
South Australia - Dry Creek, **(c)**	Use default factors	Use default factors	2.4E+03
South Australia - Mintaro, **(c)**	Use default factors	Use default factors	2.4E+03
Victoria - Jeeralang A,	2.9E+04	1.7+05 (c)	6.0E+02
Victoria - Jeeralang B,	2.9E+04	7.2E+04	6.0E+02
Western Australia – Geraldton,	4.6E+04	1.9E+05	2.4E+03
Western Australia - Kalgoorlie,	4.6E+04	1.9E+05	2.4E+03
Western Australia - Kwinana,	4.6E+04	1.9E+05	2.4E+03
Western Australia – Mungarra,	4.6E+04	1.9E+05	2.4E+03
Western Australia - Pinjar,	4.6E+04	1.9E+05	2.4E+03
Various (distillate fuelled)	3.5+05	1.3E+06	4.5E+04

Notes:

Reference: Department of the Environment, Sport and Territories 1996

TVOCs Volatile organic compounds

a. Oxides of nitrogen expressed as nitrogen dioxide, NO_2
b. Non-methane volatile organic compounds
c. Reference: Pacific Power International 2002

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

7.7 Emission Factors for Stationary Engines

The Emission Estimation Technique Manual for Combustion Engines describes the procedures and recommended approaches for estimating emissions from combustion engines. This Manual has been significantly revised since it was first published in 1999.

Tables 11 –15 of the Manual for Combustion Engines includes emission factors for the following substances:

Category 1: Acetaldehyde, benzene, 1,3 butadiene, formaldehyde, toluene, and xylene
Category 1a: TVOCs
Category 2a/b: Carbon monoxide, oxides of nitrogen, PAH, PM_{10}, sulfur dioxide.

The following points are noted with respect to emissions from combustion engines:

- Based on an engine size of 10 MW, combustion engines will not trigger the Category 1 threshold for the substances listed.
- A combustion engine burning diesel or gas would need to have a rated capacity of about 120 kW to trigger the Category 2a reporting threshold of 400 tonnes of fuel use per year (assuming 100 % capacity factor and 20% conversion efficiency).
- A combustion engine burning diesel or gas would need to have a capacity of about 600 kW to trigger the Category 2b reporting threshold of 2,000 tonnes of fuel use per year (assuming 100 % capacity factor and 20% conversion efficiency).

- Currently emission factors are available for many category 2b substances (the latest Combustion engines EET manual should be checked to determine if factors are available).

Information relevant to the reporting of substances listed in the Combustion Engines Manual is summarised in the table below. It is recommended that facilities operating combustion engines determine the appropriate level of reporting based on the category thresholds and use the relevant emission factors in the Emission Estimation Technique Manual for Combustion Engines, if more appropriate EETs are not available.

Table 16 Emission Estimation Techniques for Combustion in Combustion Engines- Oil and Natural Gas

Substance	Threshold category	Emission Reporting
Acetaldehyde	1	Unlikely to trigger threshold
Benzene	1	Unlikely to trigger threshold
1,3 butadiene	1	Unlikely to trigger threshold
Carbon monoxide	1/2a	Combustion Engines Manual
Ethylbenzene	1	Unlikely to trigger threshold
Formaldehyde	1	Unlikely to trigger threshold
Oxides of nitrogen	1/2a	Combustion Engines Manual
PM_{10}	1/2a	Combustion Engines Manual
Polycyclic aromatic hydrocarbons	2a	Combustion Engines Manual
Sulfur dioxide	1/2a	Combustion Engines Manual
Toluene (methylbenzene)	1	Unlikely to trigger threshold
TVOCs	1a/2a	Combustion Engines Manual
Xylenes	1	Unlikely to trigger threshold

7.8 Biomass Co-Firing

Biomass is assumed to include bark, sawdust, shavings, woodchips, mill rejects, sanderdust or wood trim. **It does not include treated or manufactured timber products**. Heating values for this residue range from 10MJ/kg of fuel on a wet, as-fired basis, to about 18MJ/kg for dry wood. Moisture contents may vary from 5 to 75% w/w depending on the residue type and storage conditions.

There is limited data available on emissions from co-firing with biomass. In a Dutch study (Reference: Meij 2000) eleven test series were performed at coal-fired power facilities and four at a test facility where co-combustion of secondary fuels such as sewage sludge, wood etc. was effected. The tests focussed on the emission of relevant trace elements. In these test series all the relevant streams were monitored and compared with the situation without co-combustion. Under test conditions, with a maximum of 10weight% of co-combustion, all the relative parameters were comparable to the results obtained with 100% coal firing.

The concentration of trace elements is generally lower in biomass than in coal.

Evidence from facilities co-firing biomass in NSW indicates that operational parameters will limit biomass to a maximum of about 5% of the fuel input, on a mass basis.

From the above considerations, it is recommended that for co-firing up to 10% biomass with coal (on a mass basis) the EETs for coal only combustion be adopted.

In the event of co-firing biomass in excess of 10%, it is recommended that emissions from the biomass and coal fractions be calculated separately using the relevant emission factors. Emission factors for biomass combustion can be obtained from AP-42 Wood Residue Combustion in Boilers (Reference: USEPA 1998a).

7.9 Emission Factors for Solvent Degreasing

Solvent degreasing within the fossil fuel electric power generation industry is related to maintenance activities. Table 17 contains emission factors for solvent emissions.

Table 17 Solvent Emission Factors

Solvent Used	Use	Emission Factor[a] (kg/tonne solvent used)	EFR
Dichloromethane	Vapour degreasing cold cleaners		
Uncontrolled		930	E
Controlled		890	E
Tetrachloroethylene	Vapour degreasing cold cleaners		
Uncontrolled		890	E
Controlled		850	E
Trichloroethylene	Vapour degreasing cold cleaners		
Uncontrolled		910	E
Controlled		870	E

Notes:
From Emission Estimation Technique Manual for Ferrous Foundries (National Pollutant Inventory, 1998)

7.10 Emission Factors for Storage Tanks

Facilities that have bulk storage for hydrocarbons should refer to the *Fuel and Organic Liquid Storage Manual*. The use of liquid fuels may result in the reporting threshold for a number of Category 1 substances being exceeded, depending on the quantity of fuel burnt and the concentration of relevant substances in the fuel. Table 18 shows the amounts of liquid fuel that would need to be used (kL) in any one year for the reporting threshold of 10 tonnes to be exceeded for the listed fuel constituents.

In this context "use" has been defined as fuel burnt, rather than fuel stored. As an example, if 25,000 kL of diesel were burnt in the year, more than 10 tonnes of each of the 7 listed substances in diesel fuel in the table would have been consumed, and reporting would be required for each substance. If 1,000 kL of diesel was burnt, only the use of cumene and TVOCs would have exceeded 10 tonnes.

The list of constituents and the data on their relative concentrations in the different fuels was sourced from NPI *Fuel and Organic Storage Manual*. If facilities have specific information more relevant to their operations it should be used in preference to the generic data in the *Fuel and Organic Liquid Storage Manual*.

Should the "use" of a substance be exceeded in this way, reporting of all emission pathways is required. The two principal emission pathways for these organic substances is from:

- Combustion – Tables 5 through 16 contain emission factors for combustion of these organic substances from different fuels, where available.

- Evaporation from storage tanks. A simple estimation technique is available on the NPI website (www.npi.gov.au). For those substances that trigger the reporting threshold, facilities are directed to a USEPA model (TANKS) to estimate emissions from storage tanks (http://www.epa.gov/ttn/chief/software/tanks/index.html). The use of the TANKS model theoretically allows facilities to report on the emission of a number of Category 1 NPI substances: (benzene, cumene, cyclohexane, ethylbenzene, n-Hexane, toluene and xylene.)

TANKS allows users to enter specific information about a storage tank (dimensions, construction, paint condition, etc.), the liquid contents (chemical components and liquid temperature), and the location of the tank (nearest city, ambient temperature, etc.) to generate an emissions to air report. Report features include estimates of monthly, annual, or partial year emissions for each chemical or mixture of chemicals stored in the tank.

Table 18 Indicative trigger volumes for organic substances and lead & compounds

Substance	Weight %				Trigger Volumes (kL)			
	ULP	Diesel	Heating Oil	Fuel Oil	ULP	Diesel	Heating Oil	Fuel Oil
Benzene	3.7	0.049	0.017		368	24,049	72,622	
Cumene	0.8	1.72	2.21	0.43 (1)	1,704	685	559	2,871
Cyclohexane	0.5				2,726			
1,2 Dibromomethane	0.01				136,314			
Ethylbenzene	1.7	0.1	0.03		802	11,784	41,152	
n hexane	3				454			
Lead & compounds	0.001				1,363,141			
PAHs	0.3	0.42	0.8		4,544	2,806	1,543	
Toluene	12.2	0.08	0.03		112	14,730	41,152	
TVOCs	> 99	7.6	12	3	14	155	103	
Xylenes	12.6	0.5	0.35		108	2,357	3,527	

Notes:
1. All C3-alkylated benzene isomers.

7.11 Emission Factors for Fugitive Dust

The Emission Estimation Techniques for Fugitive Emissions (1999) describes a range of processes and activities that potentially result in fugitive emissions of NPI listed substances. The Fugitive Emissions Manual generally does not include EETs but rather directs users to other appropriate Emission Manuals.

The activities and processes that are most relevant to fossil-fuel electricity generation and the appropriate emission estimation technique manuals are:

Fugitive Process/activity	Relevant Emission Estimation Technique Manual
Evaporation from fuel storage tanks	Fuel and Organic Storage / Organic Chemical Processing Industries
Vehicle movement and exhaust	Mining
Storage piles	Mining
Bulk material handling	Mining

8 Control Technologies

Emission control technologies commonly used in the Australian fossil fuel electric power generation industry are described below. These technologies are combined with environmental management systems on many facilities to reduce the overall adverse environmental impact of fossil fuel electric power generation.

8.1 Control Technologies for Emissions to Air

The control of emissions to air effected at any of the following stages in the production of electricity:

- Pre-combustion (fuel treatment);
- Combustion control; and
- Post-combustion.

Pre-combustion processes are the "cleaning" of undesirable substances from the fuel prior to combustion. The selection of fuels that can result in reduced emissions of particular substances, such as low sulfur coal could also be considered as a pre-combustion process. Pre-combustion processes have limited application for the Australian fossil fuel electric power generation industry.

Combustion control processes generally control emissions of oxides of nitrogen (NO_X) and carbon monoxide (CO) by controlling flame temperature and the fuel/air ratio used to ensure complete combustion. Common techniques include low NO_X burners, and the use of overfire air.

Post - combustion processes used in Australia primarily control the release of particulate matter (PM_{10} and Total Suspended Particulates (TSP)). Generally, this is achieved by the use of ESPs and FFs. Collection efficiencies commonly exceed 99% of the input particulate load.

With regards to emission controls for PM_{10}, in the absence of measured data, or knowledge of the collection efficiency for a particular piece of equipment, default values can be used. The default values are:

- 99.2% for electrostatic precipitators; and
- 99.8% for fabric filters.

In some circumstances, the collection efficiency of electrostatic precipitators can be improved by the injection of either sulfur trioxide or ammonia into the flue gas streams. A small fraction of the conditioning substance will pass through the ESP without reacting with flyash and be emitted to the atmosphere. Facilities injecting sulfur trioxide or ammonia in excess of the reporting threshold of 10 tonnes, should estimate the quantity of the substance that is emitted to the atmosphere. However, no emission factors have been found during this review, as the amount of substance emitted is dependent on facility-specific factors.

Currently, no fossil fuel electricity generators in Australia utilise selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) for the control of NO_X emissions. These control technologies utilise ammonia injection with or without a catalyst and some ammonia “slippage” is to be expected. A US report (Battye 1994) indicates slippage of 15 ppm and 30 ppm for SCR and SNCR respectively. The same report includes emission factors for ammonia for SCR and SNCR.

8.2 Control Technologies for Emissions to Water

Emissions to water include: discharges from a boiler water demineralising facility, cooling water blowdown, ash transport water, and floor and site drainage.

A range of techniques is used to reduce the adverse environmental impact of such discharges. Examples of techniques include:

- neutralising acid discharges;
- dense-phase ash transport (no ash transport water to dispose of);
- impoundment of site drainage e.g. settling ponds;
- "zero discharge" operations by evaporating excess water;
- use of marine disposal for saline water;
- control of floor drains discharges via oil and silt interceptors;
- mechanical condenser cleaning systems; and
- chemical substitution e.g. non solvent cleaning techniques.

8.3 Control Technologies for Emissions to Land

Emissions to land are limited to waste material and ash (for a coal fired facility).

Control techniques include:

- Utilisation of flyash for cement products;
- Controlled waste landfill or disposal off-site;
- Wet ash dams (not impacted by wind erosion);
- Twin ash dams (ash disposed to landfill or mine overburdenareas); and
- Bunding of oil and chemical storages (reduce the risk of spillage to soil).

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10 Glossary and Abbreviations

AP-42	Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume 1: Stationary Point and Area Sources (USEPA)
CEMS	Continuous emission monitoring system
CO	Carbon monoxide
EETs	Emission Estimation Techniques
EFR	Emission Factor Rating
ESP	Electrostatic precipitator
FF	Fabric filter (also called a baghouse)
g	Gram
GJ	Gigajoule (1E+09^{9} joule)
h	Hour
K	Kelvin
kg	Kilogram (1 000 gram)
L	Litre
LPG	Liquefied petroleum gas
MJ	Megajoule (1E+06 joule)
ML	Megalitre (1E+06 litre)
N_2O	Nitrous oxide
NEPM	National Environment Protection Measure
NO_X	Oxides of nitrogen
NPI	National Pollutant Inventory
OCDD	Octachloro dibenzobenzodioxin
OCDF	Octachloro dibenzofuran
Ocs	Organic compounds
PAHs	Polycyclic aromatic hydrocarbons
PCDD	Polychlorinated dibenzo-p-dioxins
PCDF	Polychlorinated dibenzofurans
PEM	Predictive emission monitoring
PJ	Petajoule (10^{15} joule)
PM_{10}	Particulate matter with aerodynamic equivalent diameter equal to or less than 10 µm
SO_X	Sulfur dioxide
STP	Standard temperature (0°C) and pressure (101.325 kPa)
TCDD	total tetrachloro dibenzodioxin
TCDF	total tetrachloro dibenzofuran
TDS	Total dissolved solids
TEQ	Toxic Equivalent
TSP	Total suspended particulates
TVOCs	Total volatile organic compounds
USEPA	United States Environment Protection Agency

Appendix A NPI Substances Relevant To Fossil Fuel Electric Power Generation

Table 19 lists the NPI listed substances that may need to be reported to the NPI by the fossil fuel electric power generation industry. Table 19 is a subset of the NPI substances. If the facility includes other unit processes some or all of the other NPI substances may need to be considered. The full list of NPI substances is in the NPI Guide.

Table 19 NPI Substances expected to be relevant to Fossil Fuel Electric Power Generation

	COLUMN 1	COLUMN 2	COLUMN 3	COLUMN 4
prefix	SUBSTANCE	CASR No.	THRESHOLD CATEGORY	THRESHOLD
	Ammonia (total)	N/A	1	10 tonnes per year
	Antimony & compounds	7440-36-0	1	10 tonnes per year
	Arsenic & compounds	7440-38-2	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Benzene*	71-43-2	1	10 tonnes per year
	Beryllium & compounds	7440-41-7	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Boron & compounds	7440-42-8	1	10 tonnes per year
	Cadmium & compounds	7440-43-9	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Carbon monoxide	630-08-0	1	10 tonnes per year
			2a	400 tonnes per year, or 1 tonne per hour
	Chlorine	7782-50-5	1	10 tonnes per year
	Chromium (III) compounds	7440-47-3	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Chromium (VI) compounds	7440-47-3	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Cobalt & compounds	7440-48-4	1	10 tonnes per year
	Copper & compounds	7440-50-8	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Cumene (1-methylethylbenzene)	98-82-8	1	10 tonnes per year
	Cyanide (inorganic) compounds	N/A	1	10 tonnes per year
	Cyclohexane	110-82-7	1	10 tonnes per year
	Dichloromethane	75-09-2	1	10 tonnes per year
	Ethylbenzene	100-41-4	1	10 tonnes per year
	Fluoride compounds*	N/A	1	10 tonnes per year
			2a	400 tonnes per year, or 1 tonne per hour
	Formaldehyde (methyl aldehyde)	50-00-0	1	10 tonnes per year

prefix	COLUMN 1 SUBSTANCE	COLUMN 2 CASR No.	COLUMN 3 THRESHOLD CATEGORY	COLUMN 4 THRESHOLD
n-	Hexane	110-54-3	1	10 tonnes per year
	Hydrochloric acid	7647-01-0	1	10 tonnes per year
			2a	400 tonnes per year, or 1 tonne per hour
	Lead & compounds	7439-92-1	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Magnesium oxide fume	1309-48-4	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Manganese & compounds	7439-96-5	1	10 tonnes per year
	Mercury & compounds	7439-97-6	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Nickel & compounds	7440-02-0	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Nickel carbonyl	13463-39-3	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Nickel subsulfide	12035-72-2	1	10 tonnes per year
			2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Oxides of Nitrogen	N/A	2a	400 tonnes per year, or 1 tonne per hour
	Particulate Matter 10.0 um	N/A		
			2a	400 tonnes per year, or 1 tonne per hour
	Polychlorinated dioxins and furans	N/A	2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Polycyclic aromatic hydrocarbons	N/A	2a	400 tonnes per year, or 1 tonne per hour
	Selenium & compounds	7782-49-2	1	10 tonnes per year
	Styrene (ethenylbenzene)	100-42-5	1	10 tonnes per year
	Sulfur dioxide	7446-09-5	1	10 tonnes per year
			2a	400 tonnes per year, or 1 tonne per hour
	Sulfuric acid	7664-93-9	1	10 tonnes per year
	Tetrachloroethylene	127-18-4	1	10 tonnes per year
	Toluene (methylbenzene)	108-88-3	1	10 tonnes per year
	Total Nitrogen	N/A	3	15 tonnes per year
	Total Phosphorus	N/A	3	3 tonnes per year
	Total Volatile Organic Compounds	N/A	1a	25 tonnes per year, or a design capacity of 25 kilotonnes for bulk storage facilities
			2a	400 tonnes per year, or 10 tonne per hour
	Trichoroethylene	79-01-6	1	10 tonnes per year
	Xylenes (individual or mixed isomers)	1330-20-7	1	10 tonnes per year

	COLUMN 1 SUBSTANCE	COLUMN 2 CASR No.	COLUMN 3 THRESHOLD CATEGORY	COLUMN 4 THRESHOLD
prefix				
	Zinc and compounds	7440-66-6	1	10 tonnes per year

Reference: National Environment Protection Council 1998 - Table *2*

Appendix B Australian Coal Properties

The tables 20 and 21 list properties of coals commonly used by the fossil fuel electricity generation industry. The tables list the composition range for many components, including for trace elements. This is due to the heterogeneous nature of coal.

These coal characteristics may be used to estimate emissions of trace elements in the absence of better data. Facilities using indicative coal concentration data included in the following tables, rather than facility-specific data, for reporting purposes should use the upper range values (in bold) unless an alternative approach has been approved by a relevant environmental jurisdiction.

Table 20 Indicative Coal Properties for Black Coals used in the Electricity Generation Industry

COAL CONSTITUENT (as fired basis)	**COAL**		
	NSW [a]	QUEENSLAND [a]	WESTERN AUSTRALIA [a]
	Range	Range	Range
% Carbon	57.1 - 64.5	53.2 - 80.5	48.1 – 52.7
% Hydrogen	3.54 - 4.1	2.6 - 6.5	2.1 – 3.4
% Nitrogen	1.15 - 1.5	0.8 - 1.5	0.8 – 0.9
% Sulfur	0.34 - 0.55	0.15 - 0.75	0.3 –0.9
% Moisture	1.9 - 7.7	5.0 - 19.0	22.0 – 29.0.
% Ash	17.4 - 25.8	11.7 - 28.0	2.5 – 10.0
OTHER ELEMENTS (mg/kg)[b]			
Antimony	<0.05 - **1.7**	0.2 - **1.41**	<1 - **2**
Arsenic	<1 - **5**	0.69 - **3.5**	<1 - **2**
Beryllium	0.8 - **7**	0.6 - **2.8**	<1 - **3**
Boron	<5 - **36**	10.0 - **38.0**	2 - **5**
Cadmium	<0.2 - **0.4**	0.04 - **0.10**	0.1 - **1.4**
Chlorine	35 - **270**	0.02 - **540**	<50 - **230**
Chromium[c]	7 - **23**	9.8 - **28.0**	1 - **10**
Chromium III	ND	ND	ND
Chromium VI	ND	ND	ND
Cobalt	1.7 - **98**	4.0 - **7.3**	2 - **18**
Copper	4 - 14	14.0 - **37.0**	1 - **13**
Fluoride	75 - **168**	51.0 - **160.0**	16 - **55**
Lead	6.7 - **16**	5.0 - **8.7**	<1 - **10**
Magnesium	ND	670 - **11,900**	ND
Manganese	5 - **360**	7.1 - **438**	<1 - **43**
Mercury	0.02 - **0.11**	0.01 - **0.1**	ND
Nickel	5 - **50**	5.1 - **16.0**	2 - **22**
Selenium	<1 - **2**	0.12 - **0.53**	ND
Zinc	6 - **370**	10.5 - **31.0**	1 - **72**
HEAT VALUE			
Higher Heating Value (MJ/kg)	22.9 - 26.27	19.3 - 27.4	19.2 – 21.5

Notes

Facilities using indicative coal concentration data, rather than facility-specific data, for reporting purposes should use the upper range values (in bold) unless an alternative approach has been approved by a relevant environmental jurisdiction.

ND	no data available
<	less than indicates the limit of detection for the element for the technique applied
a	personal communication with NSW, Queensland and West Australian electricity generating companies
b	includes compounds
c	chromium (III & VI)

Table 21 Indicative Coal Properties for Brown Coals used in the Electricity Generation Industry

COAL CONSTITUENT (as fired basis)	**COAL**	
	VICTORIA [a]	SOUTH AUSTRALIA[a]
	Latrobe Valley and Anglesea	Leigh Creek
	Range	Range
% Carbon	23.8 - 24.9	37.5
% Hydrogen	1.7 - 1.8	2.34
% Nitrogen	0.19 - 0.22	0.65
% Sulfur	0.09 - 0.14	0.2-0.3
% Moisture	61.3 - 66.5	26.2
% Ash	0.5-1.1	20.6
OTHER ELEMENTS (mg/kg)[b]		
Antimony	<0.005 - **0.01**	0.2 – **1.9**
Arsenic	0.02 - **0.07**	0.5 – **4.4**
Beryllium	<0.02 - **0.09**	<0.7 - **1.1**
Boron	1.1 - **8.6**	30 - **220**
Cadmium	0.005 - **0.11**	0.05 - **0.08**
Chlorine	220 - **290**	370 – **12,500**
Chromium[c]	0.1 - **1.4**	4 - **60**
Chromium III	ND	ND
Chromium VI	ND	ND
Cobalt	0.07 - **0.3**	<1.5 - **18**
Copper	0.1 - **2.2**	2 - **44**
Fluoride	2.9 - **13**	140 - **270**
Lead	0.1 - **0.7**	<1.5 - **37**
Magnesium	ND	0.21 - **0.33**
Manganese	0.2 - **25**	<1.5 - **370**
Mercury	0.02 - **0.12**	0.09 - **0.20**
Nickel	0.43 - **1.4**	3 - **44**
Selenium	0.1 - **0.2**	<0.4 – **0.7**
Zinc	0.4 - **7**	11 - **150**
HEAT VALUE		
Higher Heating Value (MJ/kg)	8.76 - 10.2	14.2

Notes:
Facilities using indicative coal concentration data, rather than facility-specific data, for reporting purposes should use the upper range values (in bold) unless an alternative approach has been approved by a relevant environmental jurisdiction.

ND	no data available
a	personal communication with Victorian and South Australian electricity generating companies
b	includes compounds
c	chromium (III & VI)