National Pollutant Inventory

Emission Estimation Technique Manual

for

Fossil Fuel Electric Power Generation

First Published in March 1999

EMISSION ESTIMATION TECHNIQUES

FOR

FOSSIL FUEL ELECTRIC POWER GENERATION

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1.0   Introduction

The purpose of all Emission Estimation Technique (EET) Manuals in this series is to assist Australian manufacturing, industrial, and service facilities to report emissions of listed substances to the National Pollutant Inventory (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.

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 :   3610 and all codes within the 361 ANZSIC code
                       group.

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

2.0   Process Description

Fossil fuel combustion is significant to the Australian electricity industry. Over 90% of electricity generated during 1995/96, was based on fossil fuel combustion *(Electricity Australia 1997, ESAA).* By far the greatest sources of fossil fuels for electricity generation are black coal, brown coal, and natural gas.

Coal-bed methane is a minor fuel source for the generation of electricity. Landfill gas, bagasse and other non-fossil fuels are also used for electricity generation. Emission factors for coal-bed methane and non-fossil fuels are not included in this Manual.

Fossil fuel electricity generation plants are delineated into steam plants (commonly used for large base load plants), gas turbines (commonly used for moderate sized peaking plants), cogeneration (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 plant types is considered in more detail below.

The combustion processes in fossil power generation lead to the coincidental production of a number of NPI category 1 substances (you should refer to NPI Guide at the front of this Handbook). Under the NPI, coincidental production is considered "use" with regards to Category 1 threshold tests.

Tables A2, A3 and A4 of Appendix A illustrate that for most Category 1 organic compounds, the coincidental production 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.

Reportable emissions from fossil fuel power stations are largely related to air discharges from stacks.

Chemical use within power stations tends to be relatively modest. Bulk chemicals are used to treat boiler water and cooling water for steam cycle plant.

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

Maintenance activities may require degreasing of metal components that lead to emissions to air and water.

Appendix A includes the NPI-listed substances relevant to fossil fuel electric power generation.

It is your responsibility to report to the NPI if you trip thresholds for listed substances. You should refer to the NPI Guide for further information.

2.1   Steam Cycle Plant

Most of the electricity generated in Australia is produced by steam cycle plant.

In the Australian context, steam cycle plant is based on the combustion of fossil fuel in a boiler to produce high pressure, high temperature steam that is expanded through a steam turbine coupled to a generator. The steam is condensed for reuse in the cycle. Typically, this style of plant is used for large base load generation plant. Fuels commonly used in Australia are black coal (NSW, Queensland and Western Australia), brown coal (lignite) (Victoria and South Australia), and natural gas (Victoria, South Australia and Western Australia).

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

The boiler water is commonly treated to reduce corrosion and scaling. Also, cooling water used to condense the steam is often treated to reduce algal growth. Chemical use tends to be relatively modest. Typical ranges of major chemical uses for various power stations are:

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

(Reference: *personal communication Victoria, NSW and Queensland electricity generating companies*)

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

Figure 1 is a schematic indicating the significant material flows.
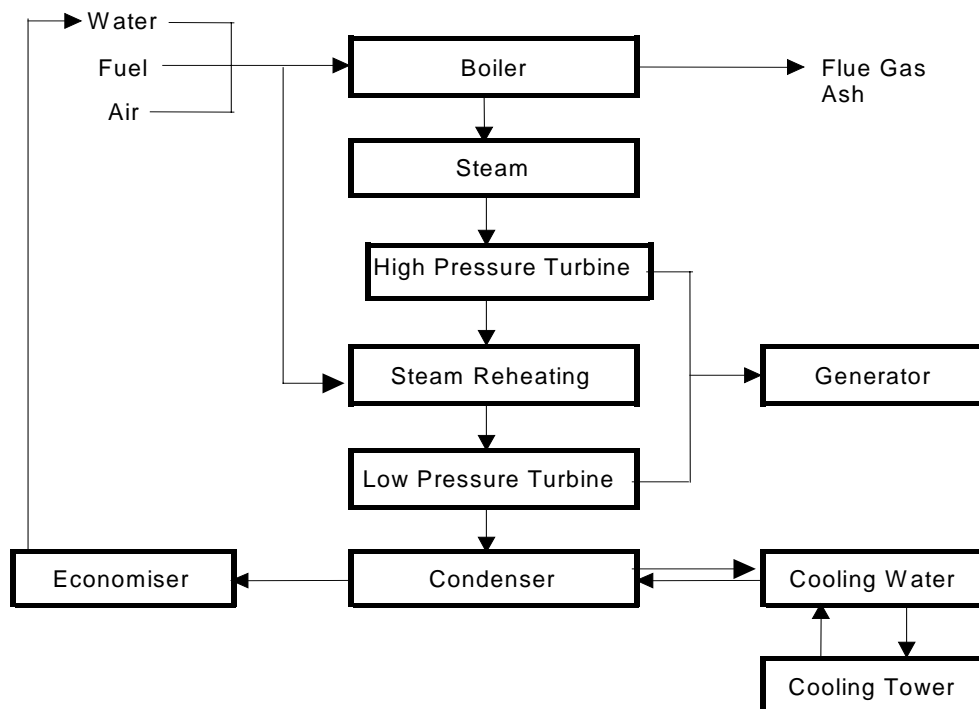
Figure 1. Basic Flow Diagram for Steam Cycle Plant
(Reference: Queensland Department of Environment and Heritage)

2.1.1 Coal-Fired Steam Cycle

Coal is the most variable of the fuels commonly used for the production of electricity. Hence, it is difficult to characterise general emission factors that apply to the range of coals.

Indicative properties of Australian coals used for electricity generation in Australia are included in Appendix B.

Coals are usually pulverised prior to combustion. Generally, dust emissions (eg. fly ash or particulate matter) from the combustion process are controlled by either electrostatic precipitators or fabric filters (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 primarily mineral matter (ie generally silicon, aluminium, iron, calcium, magnesium, potassium, sodium, and titanium in their oxide forms) including traces of other metals. Ash composition depends on the coal properties, combustion technology, and conditions.

Other emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and minor emissions of metals and organics. Carbon dioxide and water vapour are not included in the NPI listed substances.

Common boiler types used in Australia can be divided into wall firing (ie. burners on one or two walls), or tangential firing (ie. 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 (ie. coal or ash) and hydrocarbon emissions to air respectively.

2.1.2 Gas and Oil Fired Steam Cycle

The major difference between coal fired plants and gas or oil fired plants, is that gas and oil plants burn the fuel with minimal on-site pre-treatment. Generally, they do not have control equipment to collect particulate matter, as emissions of particulate matter are very low.

Emissions to air include carbon dioxide (CO_2), water vapour, oxides of nitrogen (NO_x), carbon monoxide (CO), minor emissions of metals and organics, and sulfur dioxide (SO_2) for oil firing.

Bulk hydrocarbon storage can be a source of emissions.

2.2 Gas Turbine Cycle

The gas turbine cycle relies on the expansion of very high temperature compressed gas through a gas turbine, that is coupled to a 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 gas turbine plant.

Gas turbine plants are generally smaller than steam cycle plants and may be operated with short start-up periods compared to steam cycle plants. Hence, gas turbine plants are commonly used for peaking duty, which requires plants to generate electricity at peak load periods. Gas turbines are also used as standby (ie. emergency) plants. Occasionally, gas turbine plants are used for base load operations (see the next section).

Emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), and minor emissions of metals and organics.

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

FUEL

COMPRESSOR   **TURBINE**   **GENERATOR**

AIR

EXHAUST
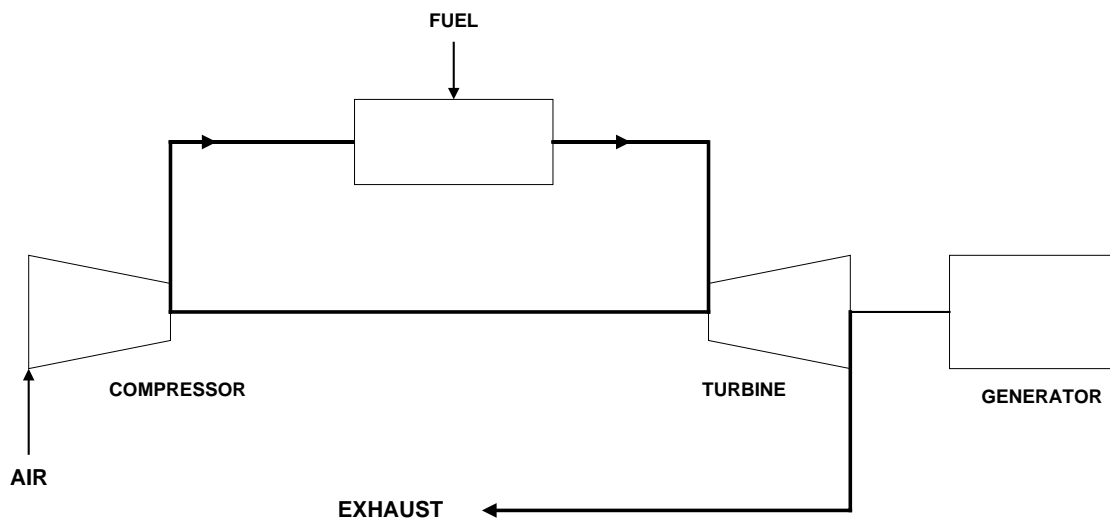
Figure 2. Simple Gas Turbine Plant
(Source: Queensland Department of Environment and Heritage)

2.3   Cogeneration

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, for another process such as industrial water heating. A special category is known as combined cycle, where the exhaust heat from a gas turbine(s) is utilised to supply all, or part, of the heat requirements of a steam cycle plant.

Hence, cogeneration plants can operate for considerable periods (to supply the heat requirements) and have overall thermal efficiencies (measure of energy utilisation) greater than simple gas turbines or stationary engine plants.

Emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), hydrocarbons, and minor emissions of metals.

Air emission factors are based on the type of prime mover (eg. gas turbine, stationary engine or boiler), and hence are included in the relevant sections.

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

2.4   Internal Combustion (Stationary) Engines

Internal combustion engines utilising petrol, natural gas, distillate, and LPG, coupled to generators, 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. Bulk hydrocarbon storage may be sources of emissions.

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

3.0   Emission Sources

The NPI Guide at the front of this Handbook details all of the reportable substances under the NPI, and their associated thresholds. This information should be consulted to determine whether or not your facility handles, manufactures, or otherwise uses any of the substances in excess of the defined thresholds (and, therefore, whether emissions of the substances are to be reported).

3.1   Emissions to Air

Emissions to air may be categorised as:

Fugitive emissions

These are emissions that are not released from a point source such as a stack. 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 generally minor for power stations. Emission factor EETs are the usual method for determining losses through fugitive emissions.

Point source emissions

These emissions are exhausted into a stack or vent, and emitted through a single point source into the atmosphere. An air emission control device, (eg an electrostatic precipitator or fabric filter (baghouse)), can be incorporated into the exhaust system to the stack prior to the atmospheric release.

The air emission sources related to fossil fuel electricity generation include:

- products of fuel combustion (from stacks);
- fugitive dust from coal stockpiles and handling equipment;
- fugitive dust from ash storage;
- organics from bulk hydrocarbon storage tanks;
- particulate emissions from wet cooling tower drift;
- emissions of solvents used for degreasing metal components; and
- emissions of chemicals used in water treatment.

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, an efficiency of 90% should be used in the emission factor equation to calculate actual mass emissions. This default should only be used if there is no other available control efficiency.

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

Table 1. Likely Air Emissions from Fossil Fuel Electric Power Generation

Technology/Fuel	Inputs	Potential Air Emissions
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, OCs, Cl_2
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, Cl_2 and trace metals.
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, OCs, Cl_2
Gas turbine/natural gas	natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers	NO_x, SO_x (very low), CO, OCs and trace metals
Gas turbine/distillate	distillate, auxiliary fuel (LPG), lubricants, degreasers	NO_x, SO_x, CO, particulates (including PM_{10}), trace metals, OCs
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
Internal combustion engine/distillate	distillate, lubricants, degreasers, coolant	NO_x, SO_x, CO, trace metals, Ocs, and PM_{10}

Notes:

Cl_2 chlorine
CO   carbon monoxide
NO_x oxides of nitrogen; include NO (nitric oxide) and NO_2 (nitrogen dioxide)
OCs   organic compounds; include volatile organic compounds, and polycyclic aromatic hydrocarbons
SO_x sulfur oxides; include SO_2 (sulfur dioxide), SO_3 (sulfur trioxide), and gaseous sulfates

3.2 Emissions to Water

Emissions of substances to water can be categorised as discharges to:

- Surface waters (eg. lakes, rivers, dams, and estuaries);
- Coastal or marine waters;
- Stormwater; and
- Groundwater.

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.

There are no emission factors included for emissions to water. Water emission sources relate primarily to steam cycle plant and can include:

- metal and boiler cleaning waste (gas and water sides);
- ash transport wastewater;
- water treatment plant discharges;
- floor drains;
- coal stockpile runoff; and
- boiler and cooling tower blowdown.

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.

Table 2. Potential Water Emissions from Fossil Fuel Electric Power Generation

Technology/Fuel	Inputs	Potential Water Emissions
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, oil spills*, degreasers*, detergents
Gas turbine/natural gas, distillate	Natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers, detergents, cooling system inhibitors	oil spills*, degreasers*, cooling system inhibitors, detergents
Internal combustion engine / natural gas, LPG, distillate	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	waste coolant*, oil spills*, degreasers*, detergents

Note:
* 		due to infrequent, unplanned incidents

3.3 Emissions to Land

Emissions of substances to land on-site include solid wastes, slurries, sediments, liquid spills and leaks, and the use of chemicals to control various elements of the environment where these emissions contain NPI-listed substances. These emission sources can be broadly categorised as:

- surface impoundments of liquids and slurries; and
- unintentional leaks and spills.

Ash disposal to a dam is considered a transfer and hence does not require reporting.

However, discharges from the dam to the environment, (eg. ash transport in wastewater to a stream) may be within the scope of the NPI (as a discharge to water).

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

Table 3. Potential Land Emissions from Fossil Fuel Electric Power Generation

Technology/Fuel	Inputs	Potential Land Emissions
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*, metals, wastes
Gas turbine/natural gas, distillate	natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers	oil spills*, wastes
Internal combustion engine/natural gas, LPG, distillate	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	oil spills*, wastes

Note:
*   due to infrequent unplanned incidents

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

Category 1 and 1a Substances

The reporting criteria for Category 1 and 1a substances, as detailed in Clause 10 of the NPI NEPM, are:

- a Category 1 listed substance is only reportable if 10 tonnes or more of the substance is used per annum;

- the only Category 1a substance is Total Volatile Organic Compounds (VOCs) for which the throughput threshold is 25 tonnes per annum;

- "use" means processed (eg. crude oil throughput, production chemicals, drilling fluids), or coincidental production (eg substances contained in produced formation water, emissions from dehydrator regeneration etc); and

- substances in proprietary mixtures are not reportable unless the substance is specified in a Material Safety Data Sheet or, in the case of any other material, the occupier of the facility could reasonably be expected to know that the substance is contained in the material.

The usage of each of the substances listed as Category 1 and 1a under the NPI must be estimated to determine whether the 10 tonnes (or 25 tonnes for VOCs) reporting threshold is exceeded. If the threshold is exceeded, emissions of these Category 1 and 1a substances must be reported for all operations/processes relating to the facility, even if the actual emissions of the substances are very low or zero.

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

4.0   Emission Factor Rating

Every emission factor has an associated emission factor rating (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 by the European Environment Agency (EEA). Consequently, the ratings may not be directly relevant to Australian industry. Sources for all emission factors cited can be found in Section 7 of this Manual. The emission factor ratings will not form part of the public NPI database.

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

5.0   Emission Estimation Techniques

Estimates of emissions of NPI-listed substances to air, water and land should be reported for each substance that triggers a threshold. The reporting list and detailed information on thresholds are contained in *The NPI Guide* at the front of this Handbook. Thresholds are based on: (a)the quantity of substance handled, manufactured, imported, coincidentally produced or otherwise used (Category 1); (b) the fuel or waste burned or energy used (Category 2); and (c) emissions to water of total nitrogen and total phosphorus (Category 3).

In general, there are four types of emission estimation techniques (EETs) that may be used to estimate emissions from your facility. The four types described in the *NPI Guide* are:-

- sampling or direct measurement;
- mass balance;
- fuel analysis or other engineering calculations; and
- emission factors.

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 your relevant environmental authority 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 reported to the NPI. The obligation to report on all relevant emissions remains if reporting thresholds have been exceeded.

It is preferable to use site-specific monitoring data where this is available, and is undertaken according to methods approved by the relevant environmental authority. Other methods based on site-specific data, such as fuel composition, can also be preferable to generalised emission factors. This will require professional consideration of the most appropriate method.

> **You are able to use emission estimation techniques that are not outlined in this document. You must, however, seek the consent of your relevant environmental authority. For example, if your company has developed site-specific emission factors, you may use these if approved by your relevant environmental authority.**

In general, direct measurement is the most accurate method for characterising emissions and, where available, such data should be used in preference to other EETs presented in

this Manual. However, additional direct measurement is not required under the NPI Measure. Direct monitoring may be undertaken as an element of other EETs.

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 (eg 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, ie. the quantity of the NPI reportable substance spilled, less the quantity recovered or consumed during clean up operations.

5.1   Using Sampling Data

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 (ie. 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 (ie 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 emissions 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

$$C_{PM} = C_f / V_{m, STP} \qquad\qquad (1)$$

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)

(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

$$E_{PM10} = C_{PM} * Q_d * 3.6 * [273 / (273 + T)] \qquad (2)$$

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
T	=	stack gas temperature in °C

Example 1

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	$1.67 * 10^{-4}$ $m^3_{STP,dry}$/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}).

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

$$
\begin{aligned}
E_{PM} &= C_{PM} * Q_d * 3.6 * [273 \div (273 + T)] \\
&= 0.072 * 8.48 * 3.6 * [273/298] \\
&= 2.01 \text{ kg/hr}
\end{aligned}
$$

To convert actual exhaust flows into STP, dry use:

$$Q_d = Q_a * (1 - MC/100) * (273/(T + 273)) * (P_s/101.325) \qquad (3)$$

Q_d	=	stack gas volumetric flow rate ($m^3_{STP,dry}$/s)
Qa	=	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: *Emission Testing Methodology for Air Pollution,* South Australian Environment Protection Agency, 1995)

Use of continuous emission monitoring systems (CEMS) is considered in Section 5.4.

5.2   Using Emission Factors

An emission factor is a tool that is used to estimate emissions to the environment. In this Manual, it relates 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 multiplied by the unit mass, volume, distance, or duration of the activity emitting the substance (eg. kilograms of sulfur dioxide emitted per tonne of coal fired).

When available, it is preferable to use site-specific information (eg monitoring data) for emission estimation.

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

$$E_{kpy,i} = [A * Ophrs] * EF * [1 - (CE_i / 100)] \qquad\qquad (4)$$

where :

$E_{kpy,i}$ = emission rate of pollutant i, kg/yr
A = activity rate, t/hr
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:

$$\text{Energy consumption (PJ/year)} = [\text{fuel consumption (tonnes/year)} * \text{higher heating value (MJ/kg)}]/10^6$$

Emission factors developed from measurements for a specific power station or process can sometimes be used to estimate emissions at other sites. Should a company have 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. As previously mentioned, it is advisable to have the emission factor reviewed and approved by State or Territory environmental authorities prior to its use for NPI estimations.

Emission factors are commonly available for air emissions, but 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* (USEPA). Sections within AP-42 are updated at different times and hence the references to AP-42 may vary in date. However, the version adopted for this manual was current in 1998.

5.2.1 Emission Factors for Black Coal Combustion (Steam Cycle)

The following tables include air emission factors for the combustion of black coal in boilers for electricity generation. Black coal is assumed to include bituminous and sub-bituminous coals. For this application, bituminous coals generally have volatile matter $\geq$ 14% dry, ash free (daf), and heating values (gross specific energy) in the range of $\geq$ 26.5 MJ/kg ash-free, moist (afm) ($\geq$ 24.0 MJ/kg provided that the crucible swelling number is $\geq$ 1). 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 0 or 1/2.
(Reference: *AS2096-1987 Classification and Coding System for Australian Coals*)

Coal specific emission factors for black coal combustion in power stations are:

For NSW coals:

NO_x	5.3 - 7.1 kg/tonne of coal
SO_2	6.72 - 11.0 kg/tonne of coal
Particulates	0.1 - 1.4 kg/tonne of coal (total)

For Queensland coals:

NO_x	3.17 - 15.6 kg/tonne of coal
SO_2	4.0 - 6.2 kg/tonne of coal
Particulates	1.18 - 1.98 kg/tonne of coal (total)

(Reference: personal communication with NSW and Queensland generating companies)

Site-specific emission factors are given in Table 5 (NO_x, CO and VOCs). In the absence of site-specific emission factors, factors from Table 4 (SO_2, NO_x, CO and PM_{10}) and Table 6 (dioxins and furans, organics, acids and cyanide) may be used.

Table 4 Emission Factors for Black Coal Combustion (NO_x, SO_2, CO and PM_{10})

SUBSTANCE	EMISSION FACTOR (kg/tonne of coal)			
	Wall-fired	Rating	Tangentially fired	Rating
Sulfur dioxide (SO_2)	$19S^a$	A	$19S^a$	A
	$(17.5S)^a$	A	$(17.5S)^a$	A
Oxides of nitrogen (NO_x)[b]	10.9	A	7.2	A
Carbon monoxide (CO)[c]	0.25	A	0.25	A
PM_{10}[f] (uncontrolled)	$1.15A^d$	E	$1.15A^{d,e}$	E
PM_{10} (ESP controlled)[g]	$0.027A^d$	D	$0.027A^d$	D
PM_{10} (FF controlled)[h]	$0.009A^d$	E	$0.009A^d$	E

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996(Tables 1.1-3, 1.1-4 and 1.1-5)

Notes:

Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired for pulverised fuel, dry bottom boilers

PM_{10} = particulate matter less than 10 μm (equivalent aerodynamic diameter)

For PM_{10} emissions it is preferable to use the uncontrolled emission factor in conjunction with the actual ESP or FF efficiency (equation 4). Use the listed values for ESP controlled and FF controlled if the actual efficiency is unknown. Hence, PM_{10} emission = 1.15A (1 - (ER/100)), where ER is the emission reduction efficiency

a. Factors in parentheses should be used to estimate gaseous emissions of SO_2 for sub-bituminous coals. S is percentage sulfur content of coal as fired eg. if fuel is 1.2% sulfur, then S=1.2. Derived from Table 1.1-3, AP-42 (1996)

b. Expressed as NO_2. Generally, 95 volume percentage or more of NO_x present in combustion exhaust will be in the form of NO, the rest NO_2. All factors represent emissions at baseline operation (ie. 60% to 110% load and no NO_x control measures). Derived from Table 1.1-3, AP-42 (1996)

c. Nominal values achievable under normal operating conditions. Values 1 or 2 orders of magnitude higher can occur when combustion is not complete. Derived from Table 1.1-3, AP-42 (1996)

d. A is the coal ash content (percentage). Emission factor is determined by multiplying weight percentage ash content of coal (as fired) by the numerical figure preceding the A. For example, if coal with 8% ash is fired in a PC wall-fired unit the PM_{10} emission factor would be 1.15 x 8, or 9.2 kg/tonne

e. No data found; emission factor for dry bottom boilers used

f. Derived from Table 1.1-4, AP-42 (1996)

g. For electrostatic precipitators (assumed efficiency of 99.2%), derived from Table 1.1-5, AP-42 (1996)

h. For fabric filter control (assumed efficiency of 99.8%), derived from Table 1.1-5, AP-42 (1996)

Example 2

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.

Equation 4 gives

$$E_{kpy,i} = [A * Ophrs] * EF * [1 - (CE_i/100)]$$

$E_{kpy,SO2}$	=	emission of SO_2
CE_i	=	0
A	=	$2 * 10^6$ tonnes
EF	=	17.5S kg/tonne (from Table 4)
S	=	0.5%

Therefore,

$E_{kpy,i}$	=	$2 * 10^6 * 17.5 * 0.5 * [1 - 0/100]$ kg/year
	=	$17.5 * 10^6$ kg/year

The site-specific emission factors included in Table 5 are based on energy input (fuel consumption by higher heating value).

Table 5 Specific Power Station Emission Factors for Black Coal Combustion (NO$_x$, CO, and VOCs)

POWER STATION	EMISSION FACTOR (tonne/PJ)		
	NOx[a]	CO	VOCs[b]
Bayswater, NSW	220	11	1.7
Eraring, NSW	220	11	1.7
Mt Piper, NSW	220	11	1.7
Liddell, NSW	260	11	1.7
Munmorah, NSW	260	11	1.7
Vales Point, NSW	260	11	1.7
Wallerawang, NSW	260	11	1.7
Callide, Queensland	523	11	1.7
Gladstone, Queensland	523	11	1.7
Stanwell, Queensland	523	11	1.7
Swanbank, Queensland	523	11	1.7
Tarong, Queensland	523	11	1.7
Collinville, Queensland	523	11	1.7
Muja A/B, Western Australia	462	11	1.7
Muja C/D, Western Australia	306	11	1.7
Bunbury, Western Australia	462	11	1.7
Kwinana A, Western Australia	462	11	1.7
Kwinana C, Western Australia	306	11	1.7

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook for Fuel Combustion Activities (Stationary Sources) (Workbook 1.1, Revision 1 National Greenhouse Gas Inventory Committee, 1996)

Notes:
PJ   petajoule (10^{15} joule)
t   tonne
VOCs   volatile organic compounds
         Emissions (tonne/year) = emission factor (tonne/PJ) x energy input (PJ/year)
         Energy input (PJ) = [fuel usage (tonne/year) x higher heating value (MJ/kg)]/10^6
a   NO$_x$ as NO$_2$
b   Non-methane volatile organic compounds
         Rating unknown

Example 3

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.

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

NO_x emissions ($E_{kpy,NOx}$)   = A * EF * [1 - (CE_i/100)]   (Equation 4)

A	= Activity (energy input)
	= 6.0 PJ/year
CE_i	= 0
$E_{kpy,NOx}$	= 6.0 (PJ/year) * 220 (tonne/PJ) * 10^3 kg/year
	= 1.32 * 10^6 kg/year

Table 6 includes air emission factors for dioxins and furans, organic compounds, acid gases, and cyanide for black coal. Table 7 contains emission factors for trace elements.

Table 6. Emission Factors for Black Coal Combustion (Dioxins and Furans, Organic Compounds, Acid Gases and Cyanide)

SUBSTANCE	EMISSION FACTOR (kg/tonne of coal)			
	Wall-fired	Rating	Tangentially fired	Rating
Polychlorinated dioxins and furans[a,b,c]	$8.8 * 10^{-10}$	D	$8.8 * 10^{-10}$	D
Polycyclic Aromatic Hydrocarbons (PAHs)[d]	$1 * 10^{-5}$	B-D	$1 * 10^{-5}$	B-D
Hydrochloric acid (as hydrogen chloride)[e]	0.6	B	0.6	B
Fluoride compounds (as hydrogen fluoride)[e]	$8 * 10^{-2}$	B	$8 * 10^{-2}$	B
Total Volatile Organic Compounds[f]	$4 * 10^{-2}$	B	$4 * 10^{-2}$	B
Cyanide	$1.3 * 10^{-3}$	D	$1.3 * 10^{-3}$	D

*Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (*Tables 1.1-11 and 1.1-12 unless otherwise stated)
Australian Methodology for Estimation of Greenhouse Gas Emissions and Sinks Workbook 1.1 (1996)
Notes:
a. Derived from Table 1.1-11, AP-42 (1996)
b. Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators, or fabric filters
c. 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
d. 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.
e. Derived from Table 1.1-14, AP-42 (1996)
f. Derived from *Australian Methodology for Estimation of Greenhouse Gas Emissions and Sinks Workbook 1.1 (1996)*

Table 7 includes emission factors with differing ratings depending on the information available regarding the coal and ash composition. If no monitoring data is available, it is recommended that site-specific emission factors derived from the emission factor equations are the preferred technique, followed by the factors listed under Factor 2 in Table 7.
(Note: the emission factors are based either on fuel consumption or energy input.)

Table 7. Emission Factors for Black Coal Combustion (Trace Elements)

SUBSTANCE	EMISSION FACTOR					
	Equation[a]	Rating	Factor 1[b] uncontrolled	Rating	Factor 2[c] controlled	Rating
	kg/PJ		kg/PJ		kg/tonne	
Antimony & compounds	$0.675 * [(C/A) * PM]^{0.63}$	A	ND		$9 * 10^{-6}$	A
Arsenic & compounds	$2.73 * [(C/A) * PM]^{0.85}$	A	294	E	$2.1 * 10^{-4}$	A
Beryllium & compounds	$1.31 * [(C/A) * PM]^{1.1}$	A	35[e]	E	$1.1 * 10^{-5}$	A
Boron & compounds	ND		ND		ND	
Cadmium & compounds	$2.17 * [(C/A) * PM]^{0.5}$	A	19	E	$2.6 * 10^{-5}$	A
Chromium compounds	$2.6 * [(C/A) * PM]^{0.58d}$	A	538 - 676[d]	E	$1.3 * 10^{-4f}$	A
Chromium (VI) compounds	ND		ND		$4 * 10^{-5}$	D
Cobalt & compounds	$1.31 * [(C/A) * PM]^{0.69}$	A	ND		$5 * 10^{-5}$	A
Copper & compounds	ND		ND		ND	
Lead & compounds	$2.87 * [(C/A) * PM]^{0.8}$	A	218	E	$2.1 * 10^{-4}$	A
Magnesium[e]	ND		ND		$5.5 * 10^{-3}$	A
Manganese	$2.71 * [(C/A) * PM]^{0.6}$	A	98 - 1282	E	$2.5 * 10^{-4}$	A
Mercury & compounds	ND		7	E	$4.2 * 10^{-5}$	A
Nickel & compounds[f]	$2.84 * [(C/A) * PM]^{0.48}$	A	443- 555	E	$1.4 * 10^{-4}$	A
Selenium & compounds	ND		ND		$6.5 * 10^{-4}$	A
Zinc & compounds	ND		ND		ND	

*Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (*Tables 1.1-15, 1.1-16 and 1.1-17 unless otherwise stated)

Notes:

PJ   petajoule (10^{15} joule)

ND   No data available

a   Derived from Table 1.1-15, AP-42 (1996) in the units kg/PJ of heat input. The equations apply to combustion of black coal and brown coal with controlled boilers and are **based on heat input**.

    C = concentration of metal in the coal, parts per million by mass (wet basis)

    A = weight fraction of ash in the coal. For example, 10% ash is 0.1-ash fraction.

    PM = site-specific emission factor for total particulate matter (kg/GJ), ie. particulate matter emitted per GJ heat input.

    To calculate emission rate use:

    Emission rate (tonne/year) = (Emission Factor (kg/PJ) x Heat Input (PJ/year))/10^3

    (Heat input (PJ) = [higher heating value(MJ/kg) x coal use (tonne/year)] /10^6)

b   Derived from Table 1.1-16, AP-42 (1996) and **based on heat input**. Applies to **uncontrolled** bituminous and sub-bituminous coal combustion, pulverised coal, and dry bottom unless otherwise noted. A range of factors represents the factors in the literature. The **emission factor is in kg/PJ** of heat input.

    Emissions should be adjusted to account for control equipment

c   Derived from Table 1.1-17, AP-42 (1996). The **emission factors (kg/tonne)** are **based on coal feed**, as fired, and apply to **controlled** coal combustion for boilers utilising electrostatic precipitators or fabric filters

d   Equation for chromium (III & VI)

e   No specific data for tangential firing

f   for chromium (III & VI)

5.2.2   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 a low moisture content. Brown coal based briquettes are used as auxiliary fuel in some Victorian power stations.
(afm: ash free, moist)
(Reference: *AS2096-1987 Classification and Coding System for Australian Coals*)

The following emission factors indicate the range for Victorian brown coal:

NO_x	1.14 - 1.6 kg/tonne of coal
SO_2	0.78 - 1.82 kg/tonne of coal
CO	0.0 - 0.12 kg/tonne of coal
Particulates	0.4 - 1.1 kg/tonne of coal (total particulates)

(Reference: personal communication with HRL Technology Pty Ltd)

Site-specific emission factors are given in Table 9 (NO_x, CO and VOCs). In the absence of site-specific emission factors, factors from Table 8 (SO_2, NO_x, CO and PM_{10}) and Table 10 (organics, acids and cyanide) can be used.

Table 8. Emission Factors for Brown Coal Combustion (SO_2, NO_x, CO and PM_{10})

SUBSTANCE	EMISSION FACTOR (kg/tonne of coal)			
	Wall-fired	Rating	Tangentially fired	Rating
Sulfur dioxide (SO_2)	$15S^a$	C	$15S^a$	C
Oxides of nitrogen (NO_x)	5.6^b	C	3.7^b	C
	2.3^c	C	3.4^d	C
			3.0^e	C
Carbon monoxide (CO)	0.13	C	ND^f	
	0.24^g	D	0.05^h	D
PM_{10} (uncontrolled)^j	$0.91A^k$	E	$1.15A^k$	E
PM_{10} (multiple cyclone controlled)^{j,m}	$0.35A^k$	E	$0.44A^k$	E

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 1.7-1 and 1.7-3 for boilers not using SO_2 control systems for pulverised coal combustion systems, unless otherwise stated)

Notes:
ND   No data available
PM_{10} For PM_{10} emissions, it is preferable to use the uncontrolled emission factor in conjunction with actual ESP or FF efficiency. Hence, PM_{10} (wall firing) = 0.91A * [1 - (CE_i/100] and PM_{10} (tangential firing) = 1.15A * [1 - (CE_i/100)] where CE_i is the overall control efficiency, (%).
a   S = weight percentage sulfur content of brown coal, wet basis. For example, if the sulfur content equals 1.2% then S = 1.2. For high sodium ash (Na_2O>8%) use 11S. For low sodium ash (Na_2O<2%) use 17S. If ash sodium content is unknown, use 15S.
b   For boilers without NO_x control
c   For boilers utilising overfire air and low NO_x burners (Table 1.7-3, AP-42(1996))
d   Derived from Table 1.4-3, AP-42 (1996) for boilers with overfire air constructed to meet the US New Source Performance Standard as defined in 40 CFR60 Subpart D, and with a heat input rate greater than 73 MW (constructed after August 1971)
e   Derived from Table 1.4-3, AP-42 (1996) for boilers with overfire air constructed to meet the US New Source Performance Standard as defined in 40 CFR60, Subpart Da (constructed after September 1978)
f   Without monitoring data, consider using emission factor for wall-fired.
g   Derived from Table 1.7-3, AP-42 (1996) for boilers utilising overfire air and low NO_x burners
h   Derived from Table 1.7-3, AP-42 (1996). Refer to boiler type described in note e
j   Derived from Table 1.7-6, AP-42 (1996). Uncontrolled relates to no particulate emission control
k   Derived from Table 1.7-6, AP-42 (1996). A = weight percentage ash content of brown coal, wet basis. For example, if brown coal is 5.3% ash, then A = 5.3
m   Estimated control efficiency of multiple cyclone is 80%, averaged over all particle sizes. This emission factor could be modified for control devices with varying efficiency by multiplying the factors by (actual efficiency/nominal efficiency (80%))

Example 4

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.

Equation 4 gives

$$E_{kpy,i} = A * EF [1 - (CE_i/100)]$$

$E_{kpy,SO2}$	=	emission of SO_2
CE_i	=	10%
A	=	$4 * 10^6$ tonnes
EF	=	15S kg/tonne (from Table 8)
S	=	0.8%

Therefore,

$$E_{kpy,i} = 4 * 10^6 * 15 * 0.8 [1 - (10/100)] \text{ kg/year}$$
$$= 43.2 * 10^6 \text{ kg/year}$$

Table 9 emission factors are based on energy input.

Table 9. Specific Power Station Emission Factors for Brown Coal Combustion (NO_x, CO, and VOCs)

POWER STATION	EMISSION FACTOR (tonne/PJ)		
	NOx	CO	VOCs[a]
Hazelwood, Victoria	151	14	1.7
Loy Yang A, Victoria	136	18	1.7
Loy Yang B, Victoria	136	18	1.7
Morwell, Victoria	151	14	1.7
Yallourn, Victoria	106	20	1.7
Northern, South Australia	136	17	1.7

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook for Fuel Combustion Activities (Stationary Sources)(Workbook 1.1, Revision 1 National Greenhouse Gas Inventory Committee, 1996)

Notes:
PJ   petajoule (10^{15} joule)
t   tonne
VOCs   volatile organic compounds
       Emissions (tonne/year) = emission factor (tonne/PJ) * energy input (PJ/year)
       Energy input (PJ) = [fuel usage (tonne/year) * higher heating value (MJ/kg)]/10^6
a   Non-methane volatile compounds
      Rating unknown

Table 10. Emission Factors for Brown Coal Combustion (Dioxins and Furans, Organic Compounds, Acid Gases, and Cyanide)

SUBSTANCE	EMISSION FACTOR[b] (kg/tonne of coal)			
	Wall-fired	Rating	Tangentially fired	Rating
Polychlorinated dioxins and furans[a,c]	$8.8 * 10^{-10}$	D	$8.8 * 10^{-10}$	D
Polycyclic Aromatic Hydrocarbons (PAHs)[b,d]	$1.04 * 10^{-5}$	B-D	$1.04 * 10^{-5}$	B-D
Benzene[f]	$6.5 * 10^{-4}$	A	$6.5 * 10^{-4}$	A
Total Volatile Organic Compounds[f]	$4 * 10^{-2}$	B	$4 * 10^{-2}$	B
Hydrochloric acid (as hydrogen chloride)[e]	0.6	B	0.6	B
Fluoride compounds (as hydrogen fluoride)[e]	$7.5 * 10^{-2}$	B	$7.5 * 10^{-2}$	B
Cyanide	$1.3 * 10^{-3}$	D	$1.3 * 10^{-3}$	D

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 1.1-11 and 1.7-14 for pulverised coal combustion systems, unless otherwise stated)
Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook for Fuel Combustion Activities (Stationary Sources) Workbook 1.1, Revision 1 (National Greenhouse Gas Inventory Committee, 1996)

Notes:
a   No specific emission factors available for brown coal. Use as default. Derived from Table 1.1-11, AP-42 (1996)
b   Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators or fabric filters. Derived from Table 1.7-9, AP-42 (1996). These emission factors are the same as for black coal.
c   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
d   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
e   Derived from Table 1.7-14, AP-42 (1996)
f   *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook for Fuel Combustion Activities (Stationary Sources)* Workbook 1.1, Revision 1 (National Greenhouse Gas Inventory Committee, 1996)

The following table includes emission factors for trace elements for brown coal combustion. AP-42 suggests that the equations included in Table 7 for black coal can be used for brown coal. However, due to the relatively high moisture content of Australian brown coals used for electricity generation, this is not recommended.

Table 11. Emission Factors for Brown Coal Combustion (Trace Elements)

SUBSTANCE	EMISSION FACTOR			
	Factor 1[a]	Rating	Factor 2[b]	Rating
	kg/PJ		kg/tonne	
Antimony & compounds	ND		$9 * 10^{-6}$	A
Arsenic & compounds	598	E	$2.1 * 10^{-4}$	A
Beryllium & compounds	56	E	$1.1 * 10^{-5}$	A
Boron & compounds	ND		ND	
Cadmium & compounds	21	E	$2.6 * 10^{-5}$	A
Chromium compounds	645 - 808[c]	E	$1.3 * 10^{-4c}$	A
Chromium (VI) compounds	ND		$4 * 10^{-5}$	D
Cobalt & compounds	ND		$5 * 10^{-5}$	A
Copper & compounds	ND		ND	
Lead & compounds	ND		$2.1 * 10^{-4}$	A
Magnesium[d]	ND		$5.5 * 10^{-3}$	A
Manganese	6966	E	$2.5 * 10^{-4}$	A
Mercury & compounds	9	E	$4.2 * 10^{-5}$	A
Nickel & compounds[e]	399 - 499	E	$1.4 * 10^{-4}$	A
Selenium & compounds	ND		$6.5 * 10^{-4}$	A
Zinc & compounds	ND		ND	

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 1.7.13 for pulverised coal combustion systems, unless otherwise stated)

Notes:
ND   No data available
a   Derived from Table 1.7-12, AP-42 (1996) and **based on heat input**. Applies to **uncontrolled** brown coal combustion, pulverised coal, dry bottom unless otherwise noted. A range of factors represents the factors in the literature. The **emission factor is in kg/PJ** of heat input.
        Emission (tonnes per year) = [emission factor (kg/PJ) * higher heating value (MJ/kg) * coal usage (tonnes/year)]/10^9
        Adjust emission rate for control equipment
b   Derived from Table 1.7-13, AP-42 (1996). The **emission factors (kg/tonne)** are **based on coal feed**, as fired, and apply to controlled coal combustion for boilers utilising electrostatic precipitators or fabric filters
c   Equation or factor for chromium (III & VI)
d   Table 2 (NEPM) lists magnesium oxide fume (no separate emission factor)
e   Table 2 (NEPM) also lists nickel carbonyl and nickel subsulfide (no separate emission factor)

5.2.3   Emission Factors for Natural Gas Combustion (Steam Cycle)

Natural gas is used in steam cycle electricity generation plants in South Australia, Western Australia, and Victoria. Natural gas is also used to fuel gas turbines, and less commonly to fuel stationary engines to generate electricity. These plant types are considered later.

Site-specific emission factors are included in Tables 12 and 13.

The default emission factors are primarily derived from the Compilation of Air Emission Factors (AP-42), and hence relate to United States natural gas. Where possible, data for the specific site natural gas supply should be used.

Table 12. Emission Factors for Natural Gas Combustion (SO$_2$, NO$_X$, CO, and PM$_{10}$)

SUBSTANCE	EMISSION FACTOR (tonne/PJ)			
	Wall-fired	Rating	Tangentially fired	Rating
Sulfur dioxide (SO$_2$)	0.25[d]	A	0.25[d]	A
Oxides of nitrogen (NO$_x$)			97[a]	U
	117[b]	U		
	226[c]	U		
Carbon monoxide (CO)	35[a]	U		
	6[b]	U		
	16[c]	U		
PM$_{10}$	1.3	D	1.3	D

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 1.4-1 and 1.4.2)

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)), National Greenhouse Gas Inventory Committee, 1996

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   Derived from Table 1.4-2, AP-42 (1996), assuming 100% conversion of sulfur to SO$_2$, a natural gas sulfur content of 4,600 g/10^{6}Nm^3 and higher heating value of 38 MJ/Nm^3

(1)   *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)),* National Greenhouse Gas Inventory Committee, 1996

Table 13. Emission Factors for Natural Gas Combustion (Dioxins and Furans, Organic Compounds, and Acid Gases)

SUBSTANCE	EMISSION FACTOR[a] (tonne/PJ)			
	Wall-fired	Rating	Tangentially fired	Rating
Polychlorinated dioxins and furans	ND		ND	
Polycyclic Aromatic Hydrocarbons (PAHs)[f]	$2.9 * 10^{-4}$	D-E	$2.9 * 10^{-4}$	D-E
Hexane	0.76[g]	E		
Volatile Organic Compounds	2.3[b]	C	2.3[b]	C
			0.6[c]	U
	0.6[d]	U		
	0.6[e]	U		
Hydrochloric acid (as hydrogen chloride)	ND		ND	
Fluoride compounds (as hydrogen fluoride)	ND		ND	

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 1.4-2)

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)), National Greenhouse Gas Inventory Committee, 1996

Notes:

a   Based on heat input
         Heat input (PJ) = (higher heating value) x (fuel used)
b   Derived from Table 1.4-2, AP-42 (1996) assuming a heating value of 38 MJ/Nm^3
c   For Newport Power Station, Victoria (1)
d   For Torrens Island Power Station, South Australia (1)
e   For Kwinana B Power Station, Western Australia (1)
f   Emission factor for PAHs derived from Table 1.4-3, AP-42 (1996). PAHs include: 2-
         Methylnaphthalene, 3-Methylchloranthene, 7,12- Dimethylbenz(a)anthracene, Acenaphthene,
Acenaphthylene, Anthracene, Benz(a)anthracene, Benzo(a)pyrene, Benzo(b)fluoranthene,
Benzo(g,h,i)perylene, Benzo(k)fluoranthene, chrysene, Dibenzo(a,h)anthracene, Fluoranthene, Fluorene,
indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene.
g   Hexane derived from Table 1.4-3, AP-42 (1996)
(1)   *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)),* National Greenhouse Gas Inventory Committee, 1996

Table 14 includes emission factors for trace elements emissions from natural gas, steam cycle plant.

Table 14. Emission Factors for Natural Gas Combustion (Trace Elements)

SUBSTANCE	Factor	Rating
	tonne/PJ	
Antimony & compounds	ND	
Arsenic & compounds	$8.5 * 10^{-5}$	E
Beryllium & compounds[a]	$<5.1 * 10^{-6}$	E
Boron & compounds	ND	
Cadmium & compounds	$4.6 * 10^{-4}$	D
Chromium (III) compounds[b]	$5.9 * 10^{-4}$	D
Chromium (VI) compounds	note b	
Cobalt & compounds	$3.5 * 10^{-5}$	D
Copper & compounds	$3.6 * 10^{-4}$	C
Lead & compounds[c]	$2.4 * 10^{-4}$	D
Magnesium	ND	
Manganese	$1.6 * 10^{-4}$	D
Mercury & compounds	$1.1 * 10^{-4}$	D
Nickel & compounds	$8.8 * 10^{-4}$	C
Selenium & compounds[a]	$<1.0 * 10^{-5}$	E
Zinc & compounds	$1.2 * 10^{-2}$	E

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 1.4-2 and 1.4-4)

Notes:

Emission factors derived from Table 1.4-4, AP-42 (1996) and assuming an average higher heating value of 38 MJ/Nm^3, unless otherwise stated

ND   No data available
a   Based on method detection limits
b   Total chromium
c   Derived from Table 1.4-2, AP-42 (1996)

5.2.4   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 15. Emission Factors for Oil Combustion (SO_2, NO_x, CO, and PM_{10})

SUBSTANCE	FUEL	EMISSION FACTOR ($kg/10^3$ L)			
		Wall-fired	Rating	Tangentially fired	Rating
Sulfur dioxide (SO_2)	Fuel Oil	18.9S[a]	A	18.9S[a]	A
	Distillate	17S[a]	A	17S[a]	A
Oxides of nitrogen (NO_x)[c]	Fuel Oil	8.0	A	5.0	A
	Distillate[e]	2.4	A	2.4	A
Carbon monoxide (CO)[d]	Fuel Oil	0.6	A	0.6	A
	Distillate	0.6	A	0.6	A
PM_{10} (uncontrolled)	Fuel Oil	0.71A[b]	C	0.71A[b]	C
PM_{10} (ESP controlled)	Fuel Oil	0.005	E	0.005	E

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 1.3-1 and 1.3-3)

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)), National Greenhouse Gas Inventory Committee, 1996

Notes:

   Emission factors are based on fuel usage (10^3 L)

   Emissions (kg/year) = [emission factor ($kg/10^3$ L) * fuel usage (10^3 L/year)]

PM_{10} For PM_{10} emissions, it is preferred to use the uncontrolled emission factor in conjunction with the actual ESP or FF efficiency. Hence, PM_{10} emissions = 0.71A *

   (1 - CE_i/100) where CE_i is the overall emission control efficiency (%)

L   Litre

a   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

b   Particulate emission factors for residual oil combustion without emission control are, on average, a function of fuel oil grade and sulfur content. Use A = 0.13(S) + 0.05 $kg/10^3$ L

c   For Bell Bay Power Station, Tasmania use 7.4 $kg/10^3$ L. Based on Reference (1) assuming a heating value of 39.7 MJ/kg.

d   For Bell Bay Power Station, Tasmania use 0.56 $kg/10^3$ L. Based on Reference (1) assuming a heating value of 39.7 MJ/kg.

e   Firing configuration unknown

(1)   *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)),* National Greenhouse Gas Inventory Committee, 1996

Table 16. Emission Factors for Oil Combustion (Dioxins and Furans, Organic Compounds, and Acid Gases)

SUBSTANCE	FUEL	EMISSION FACTOR ($kg/10^3$ L)			
		Wall-fired	Rating	Tangentially fired	Rating
Polychlorinated dioxins and furans[a]	Fuel Oil	$3.7 * 10^{-10}$	E	$3.7 * 10^{-10}$	E
Polycyclic Aromatic Hydrocarbons (PAHs)[b]	Fuel Oil	$1.4 * 10^{-4}$	C-D	$1.4 * 10^{-4}$	C-D
Volatile Organic Compounds[c]	Fuel Oil Distillate[d]	$9.1 * 10^{-2}$ $2.4 * 10^{-2}$	A A	$9.1 * 10^{-2}$ $2.4 * 10^{-2}$	A A
Hydrochloric acid (as hydrogen chloride)		ND			
Fluoride compounds (as hydrogen fluoride)	see Table 17				

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 1.3-2 and 1.3-8)

Notes:

      Emissions (kg/year) = [emission factor ($kg/10^3$ L) x fuel usage (10^3 L/year)]

L   Litre

a   Includes only OCDD (based on data from one source), no data for distillate

b   PAHs 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

c   Taken as non-methane total organic compounds, derived from Table 1.3-2. For Bell Bay Power Station, Tasmania use $8.3 * 10^{-2}$ $kg/10^3$ L. Derived from Reference (1) based on a heating value of 39.7 MJ/kg

d   Derived from Table 1.3-2 (AP-42) for industrial boilers

(1)   *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)),* National Greenhouse Gas Inventory Committee, 1996

Table 17 includes trace elements emissions from oil combustion in steam plant.

Table 17. Emission Factors for Oil Combustion (Trace Elements)

SUBSTANCE	Fuel	Factor kg/ 10^3 L^a	Rating
Antimony & compounds	Fuel Oil	$6.3 * 10^{-4}$	E
	Distillate	ND	
Arsenic & compounds	Fuel Oil	$1.5 * 10^{-4}$	E
	Distillate	$7.2 * 10^{-5}$	E
Beryllium & compounds	Fuel Oil	$3.3 * 10^{-6}$	C
	Distillate	$4.3 * 10^{-5}$	E
Boron & compounds	ND		
Cadmium & compounds	Fuel Oil	$4.8 * 10^{-5}$	C
	Distillate	$1.9 * 10^{-4}$	E
Chromium compounds^b	Fuel Oil	$1 * 10^{-4}$	C
	Distillate	$1.14 * 10^{-3}$	E
Chromium (VI) compounds	Fuel Oil	$3 * 10^{-5}$	C
	Distillate	ND	
Cobalt & compounds	Fuel Oil	$4.3 * 10^{-6}$	D
	Distillate	ND	
Copper & compounds	Fuel Oil	$2.1 * 10^{-4}$	C
	Distillate	ND	
Fluoride	Fuel Oil	$4.5 * 10^{-3}$	D
	Distillate	ND	
Lead & compounds	Fuel Oil	$1.8 * 10^{-4}$	C
	Distillate	$1.52 * 10^{-4}$	E
Magnesium	ND		
Manganese	Fuel Oil	$3.6 * 10^{-4}$	C
	Distillate	$2.4 * 10^{-4}$	E
Mercury & compounds	Fuel Oil	$1.4 * 10^{-5}$	D
	Distillate	$5.1 * 10^{-5}$	E
Nickel & compounds	Fuel Oil	$1 * 10^{-2}$	C
	Distillate	$2.9 * 10^{-3}$	E
Selenium & compounds	Fuel Oil	$8.2 * 10^{-5}$	C
	Distillate	ND	
Zinc & compounds	Fuel Oil	$3.5 * 10^{-5}$	D
	Distillate	ND	

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 1.3-9 and 1.3-10)

Notes

    Emissions (kg/year) = [emission factor (kg/10^3 L) x fuel usage (10^3 L/year)]

L   Litre

    Fuel oil factors derived from Table 1.3-10 (AP-42) for No 6 Fuel Oil combustion

a   Factors for distillate derived from Table 1.3-9 (AP-42), assuming a higher heating value for industrial distillate of 39.6 MJ/L (Reference: *Projections of Energy Demand and Supply*, ABARE)

b   Chromium (III & VI)

5.2.5 Emission Factors for LPG Combustion (Steam Cycle)

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

Table 18 Emission Factors for LPG Combustion (SO_2, NO_X, CO, and PM_{10})

SUBSTANCE	EMISSION FACTOR ($kg/10^3$ L)[a]			
	Butane	Rating	Propane	Rating
Sulfur dioxide (SO_2)[b]	$1.9 * 10^{-4}$S	E	$2.1 * 10^{-4}$S	E
Oxides of nitrogen (NO_X)[c]	2.5	E	2.3	E
Carbon monoxide (CO)	0.43	E	0.38	E
PM_{10} [d]	0.07	E	0.07	E
Total Volatile Organics[e]	0.07	E	0.06	E

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 1.5-1)

Notes

       Emissions (kg/year) = [emission factor ($kg/10^3$ L) * fuel usage (10^3 L/year)]
L   Litre
a   Derived from Table 1.5-1, AP-42) 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, AP-42, for total organic compounds

5.2.6 Emission Factors for Stationary Gas Turbines

Emission factors for stationary gas turbines fuelled on natural gas or distillate are included in this section. These factors should also be used for cogeneration systems based on gas turbines. Factors for gas turbines utilising exhaust gas control technology are included. These technologies include:

❑ 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.

❑ Selective Catalytic Reduction (SCR) systems that reduce NO_X emissions by injecting ammonia into the exhaust gases upstream of a catalyst.

Table 19 includes general emission factors, whereas Table 20 contains site-specific emission factors for NO_x, CO, and VOCs.

Table 19. Emission Factors for Gas Turbines (SO_2, NO_x, CO, PM_{10}, VOCs, Ammonia, and Formaldehyde)

SUBSTANCE	EMISSION FACTOR (tonne/PJ)[a]			
	Natural Gas		Distillate	
	Factor	Rating	Factor	Rating
Sulfur dioxide (SO_2)[b]	404S	B	473S	B
Oxides of nitrogen (NO_x)	189[c]	C	300[c]	C
	60.2[d]	C	125[d]	E
	51.6[e]	C		
	3.8[f]	C		
Carbon monoxide (CO)	47[c]	D	20.6[c]	D
	121[d]	C	8.3[d]	E
	69[e]	C		
	3.6[f]	C		
PM_{10} (uncontrolled)[g]	18	E	26.2	E
PM_{10} (controlled)			16[d]	E
Total Volatile Organics[h]	10.3	D	7.3	D
	6.0[f]	C	2.1[d]	E
Ammonia[j]	2.8[f]	C	ND	
Formaldehyde[k]	1.2[f]	C		

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Tables 3.1-1, 3.1-2 and 3.1-3)

Notes

Emissions (kg/year) = emission factor (tonnes/PJ) * heat input (PJ/year)* 10^3

ND   No data available

a   PJ (petajoule) = 10^{15} joule.

b   All sulfur in the fuel is assumed to be converted to SO_2. S = percentage sulfur in the fuel. Hence, if the fuel has 1.3% sulfur, S = 1.3. If S is unknown use 0.25 tonne/PJ (derived from Table 3.1-1, AP-42)

c   uncontrolled exhaust

d   water injection (0.8 water/fuel ratio)

e   steam injection (1.2 water/fuel ratio)

f   Selective catalytic reduction (with water injection)

g   total PM_{10} (including solids and condensables)

h   Total organic compounds (as methane) used as surrogate for VOCs

j   Ammonia from injection systems. No data for uncontrolled systems, but expected to be negligible

k   Formaldehyde only listed for selective catalytic reduction. No data for uncontrolled systems, but expected to be negligible

Table 20. Specific Power Station Emission Factors for Gas Turbines (NO$_x$, CO, and VOCs)

POWER STATION	EMISSION FACTOR (tonne/PJ)[a]		
	NO$_x$	CO	VOCs[b]
Jeeralang A, Victoria	166[c]	29	0.6
Jeeralang B, Victoria	72	29	0.6
Kwinana, Western Australia	190	46	2.4
Geraldton, Western Australia	190	46	2.4
Kalgoorlie, Western Australia	190	46	2.4
Mungarra, Western Australia	190	46	2.4
Pinjar, Western Australia	190	46	2.4
Dry Creek, South Australia	383	16	2.4
Mintaro, South Australia	190	46	2.4
Channel Island, Northern Territory	190	46	2.4
Various (distillate fuelled)	1322	349	45

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Workbook 1.1 (Fuel Combustion Activities (Stationary Sources)), National Greenhouse Gas Inventory Committee, 1996

Notes
VOCs   Volatile organic compounds
a   PJ = petajoule (10^{15} joule).
b   Non-methane volatile organic compounds
            Rating unknown
c   Supplied by Ecogen Energy

Gas turbines firing distillate may emit trace elements originating from the metals content of the fuel. Use the fuel analysis where available, assuming all metals pass through the turbine. If a fuel analysis is unavailable, use the factors in Table 21.

Table 21. Emission Factors for Gas Turbines (Trace Elements)

SUBSTANCE	Emission Factor[a]	
	tonne/PJ	Rating
Antimony & compounds	$9.5 * 10^{-3}$	E
Arsenic & compounds	$2.1 * 10^{-3}$	E
Beryllium & compounds	$1.4 * 10^{-4}$	E
Boron & compounds	$2.8 * 10^{-2}$	E
Cadmium & compounds	$1.8 * 10^{-3}$	E
Chromium (III) compounds[b]	$2 * 10^{-2}$	E
Chromium (VI) compounds	ND	
Cobalt & compounds	$3.9 * 10^{-3}$	E
Copper & compounds	$5.6 * 10^{-1}$	E
Fluoride	ND	
Lead & compounds	$2.5 * 10^{-2}$	E
Magnesium	$9.9 * 10^{-2}$	E
Manganese	$1.5 * 10^{-1}$	E
Mercury & compounds	$3.9 * 10^{-4}$	E
Nickel & compounds	$5.2 * 10^{-1}$	E
Selenium & compounds	$2.3 * 10^{-3}$	E
Zinc & compounds	$2.9 * 10^{-1}$	E

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 3.1-4)

Notes:
a   For distillate fuelled gas turbines only (trace elements negligible for natural gas)
b   chromium

5.2.7   Emission Factors for Stationary Engines

Suitable emission factors for combustion engines used to generate electricity are contained in *the Emission Estimation Technical Manual for Combustion Engines.*

5.2.8   Emission Factors for Wet Cooling Towers

Cooling towers are frequently used to dissipate heat from cooling water used in condensers for steam cycle generation plant. Two common forms of cooling towers are used for such plant: natural draft, and induced draft (fan assisted) cooling towers.

Emissions from wet cooling towers are related to the drift of liquid, containing suspended and dissolved solids. Dissolved solids found in cooling tower drift can consist of mineral matter, chemicals for corrosion inhibition, etc.

Table 22 contains emission factors for wet cooling towers.

A conservatively high PM_{10} emission factor can be obtained by multiplying the total liquid drift factor (from Column 2 in Table 22), by the total dissolved solids (TDS) fraction in the circulating water and assuming that, once the water evaporates, all remaining solid particles are within the PM_{10} size range.

If TDS data is unavailable, a source specific TDS content can be estimated by obtaining the TDS data for the make-up water, and multiplying by the cooling tower cycles of concentration. The cycles of concentration ratio is the ratio of a measured parameter for the cooling tower water, (eg conductivity) to that parameter for the make-up water.

If neither of these methods can be used, the factor in Column 5 may be used.

Table 22. Emission Factors for Wet Cooling Towers

TOWER TYPE	TOTAL LIQUID DRIFT[a]			PM_{10}	
	Circulating Water Flow[a]	kg/ML[b]	Rating	kg/ML[c]	Rating
Induced Draft	$2 * 10^{-2}$	200	D	2.3	E
Natural Draft	$8.8 * 10^{-4}$	8.8	E	ND	

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 13.4-1)

Notes:
ND   No data available
a   Total liquid drift is water droplets entrained in the cooling tower exit air stream. Factors are percentage of circulating water flow.
b   Total liquid drift in kilograms/ML of circulating water flow
c   Implies an effective TDS content of 12,000 ppm in circulating water

5.2.9   Emission Factors for Solvent Degreasing

Solvent degreasing within the fossil fuel electric power generation industry is related to maintenance activities. Table 23 contains emission factors for solvent emissions.

Table 23. Solvent Emission Factors

Solvent Used	Use	Emission Factor[a] (kg/kg solvent used)	Emission Factor Rating
Dichloromethane	Vapour degreasing		
Uncontrolled	Cold cleaners	0.930	E
Controlled		0.890	E
Tetrachloroethylene Uncontrolled	Vapour degreasing		
Controlled	Cold cleaners	0.890	E
		0.850	E
Trichloroethylene	Vapour degreasing		
Uncontrolled	Cold cleaners	0.910	E
Controlled		0.870	E

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

5.2.10 Emission Factors for Storage Tanks

Facilities that have bulk storages for hydrocarbons are referred to the *Fuel and Organic Liquid Storage Manual.*

5.2.11 Emission Factors for Fugitive Dust

Fugitive dust emissions may be relevant to facilities storing and handling coal and ash for PM_{10} and trace elements (for large emissions). Sound practice should minimise fugitive emissions that, in practice, should be minor when compared with the emissions from combustion.

Techniques for estimating fugitive emissions from the surface (eg. ash dams) are limited. Options include measuring ambient dust levels upwind and downwind of the source of interest and/or applying predictive mathematical models.

Fugitive emissions of dust are related to many factors that are not readily predictable, such as surface crusting, and roughness. The major influencing factors on total fugitive dust emissions include surface disturbance (eg ash-moving, etc), surface wind velocity and soil characteristics (eg moisture content, erodibility, etc). Fugitive dust emissions tend to be significant at the commencement of an event (eg wind change) and decrease as the surface material becomes depleted of the smaller particles. (Reference: *Air Pollution Engineering Manual,* Air and Waste Management Association, 1992)

For estimation techniques refer to the *Emission Estimation Technical Manual for Mining.*

5.3   Using Fuel Analysis Data

Fuel analysis can be used to predict SO_2, metals, and other emissions based on application of conservation laws, if fuel rate (Q_f) is measured. 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:

$$E_{kpy,i} = Q_f * \text{pollutant concentration in fuel} * (MW_p / EW_f) \qquad (5)$$

where:

$E_{kpy,i}$ = emissions of pollutant i, kg/yr
Q_f = fuel use (kg/hr)
MW_p = molecular weight of pollutant emitted (kg/kg-mole)
EW_f = elemental weight of pollutant in fuel (kg/kg-mole)

Equation 5 is most appropriate for volatile elements in coal, such as fluorine and chlorine. For elements that are captured effectively, either in bottom ash or fly ash (ie most metals with the possible exception of mercury) equation 5 can result in overestimation of emissions. If coal concentrations and ash fractions are known, emission estimates can be calculated without stack measurements by utilising mass balance techniques.

For instance, SO_2 emissions from oil combustion can be calculated based on the concentration of sulfur in the oil. This approach assumes complete conversion of sulfur to SO_2. 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 5.

Example 5

This example shows how SO_2 emissions can be calculated from oil combustion, based on fuel analysis results, and the fuel flow information. The power station is assumed to operate 150 hours per year on oil.

$E_{kpy,SO2}$ can be calculated using Equation (5)

Assume a given Q_f = 2 000 kg/hr
Weight percent sulfur in fuel = 1.17%
Operating hours = 150 hr/yr

$$
\begin{aligned}
E_{kpy,SO2} &= Q_f * \text{pollutant concentration in fuel} * (MW_p / EW_f) * \text{OpHrs} \\
&= (2\,000) * (1.17 / 100) * (64 / 32) \text{ kg/hr} \\
&= 46.8 \text{kg/hr} * 150 \text{ hr/yr} \\
&= 7.0 * 10^3 \text{ kg/year}
\end{aligned}
$$

5.4   Using CEMS Data

Using CEMS (continuous emission monitoring systems) data to estimate emissions can be applicable for 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, VOCs, 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 local environmental authority as a requirement for NPI emission estimations.

Table 24. Example CEM Output Averaged for a Power Plant Firing Fuel Oil

Time	O_2 (%V)	Concentration (C) (ppmvd)				Gas Flow Rate (Q) ($m^3_{stn.dry}$/s)	Oil Use Rate (A) (tonnes/ hour)
		SO_2	NO_X	CO	VOCs		
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 (6) and Example 4.

$$E_i = (C * MW * Q * 3\ 600) / (V * 10^6) \qquad (6)$$

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 (7) and Example 6.

$$E_{kpy,i} = (E_i * OpHrs) \qquad (7)$$

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 (8)) 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 6.

$$(E_{kpt,i})_1 = E_i / A \qquad (8)$$

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
A	=	fuel oil consumption, tonnes/hr

Example 6

This example shows how SO_2 emissions can be calculated using Equation (6) based on the average CEMS data for Time Period 1 shown in the Table 24.

$$E_{SO2} = (C * MW * Q * 3\ 600) / (V * 10^6)$$
$$C = 150.9\ ppmv$$
$$MW = 64$$
$$Q = 8.52\ m^3_{stp,dry}/s$$
$$V = 22.4\ m^3/kg\text{-}mole$$

$$E_{SO2} = (150.9 * 64 * 8.52 * 3\ 600) / (22.4 * 10^6)$$
$$= 296\ 217\ 907 / 22\ 400\ 000$$
$$= 13.22 kg/hr$$

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

For time Period 3
$$E_{kpy,SO2} = 11.2\ kg/hr$$

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 = $(13.22 * 1500) + (12.56 * 2000) + (11.2 * 1800)$ 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 (8):

$$E_{kpt,SO2} = E_{SO2} / A$$
$$= 13.22 / 290$$
$$= 4.56 * 10^{-2}\ kg\ SO_2\ \text{emitted per tonne of fuel oil consumed}$$

Similar calculations could be undertaken for the other time periods.

5.5   Using Predictive Emissions Monitoring

An example of predictive emissions monitoring (PEM) that could be used to develop a PEM protocol for acceptable NPI reporting, would need to account for the variability in these parameters, and consequently, may require a complex testing algorithm.

To develop this algorithm, correlation testing of the process variables could be conducted over a range of potential operating conditions for a suite of NPI-listed substances including VOCs and SO_2. Based on the test data, a mathematical correlation can be developed that predicts emissions using the various parameters.

PEMS is difficult to apply, and is likely to have limited application in the Australian fossil fuel electricity industry.

6.0   Control Technologies

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

New combustion technologies such as coal gasification and fluidised bed combustion, are still in the developmental stages for electricity generation in Australia. Also, since Australian coals are relatively low in sulfur, flue gas desulfurisation has not been required.

Cogeneration, described in Section 2.3, improves the efficiency of fuel utilisation. Cogeneration plant, generally using natural gas, has been developed in Australia where a suitable use for the heat is available.

6.1   Control Technologies for Air Emissions

Control of air emissions from fossil fuel electric power generation may be considered as:

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

Pre-combustion processes relate to the "cleaning" of undesirable substances from the fuel prior to combustion. This could also include the selection of fuels that can result in reduced emissions of particular substances, such as low sulfur coal. Pre-combustion processes have limited application for Australian fossil fuel electric power generation.

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

Post - combustion processes used in Australia primarily relate to the control of particulate matter. Generally, this is achieved by the use of electrostatic precipitators and fabric filters (baghouses). Collection efficiencies commonly exceed 99% of input particulate load.

6.2 Control Technologies for Water Emissions

Water emissions include discharges from boiler water demineralising plant, cooling water blowdown, ash transport water, and floor and site drainage.

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

- neutralising of acid discharges;
- dense-phase ash transport (no ash transport water to dispose of);
- impoundment of site drainage eg. 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 eg. non solvent cleaning techniques.

6.3 Control Technologies for Land Emissions

Land discharges are limited to waste material and ash (for coal fired plant).

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 overburden areas); and
- Bunding of oil and chemical storages (reduce the risk of spillage to soil).

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8.0   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
ESP   Electrostatic precipitator
FF   Fabric filter
g   Gram
GJ   Gigajoule (10^9 joule)
h   Hour
K   Kelvin
kg   Kilogram (1,000 gram)
L   Litre
LPG   Liquefied petroleum gas
MJ   Megajoule (10^6 joule)
ML   Megalitre (10^6 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
VOCs   Volatile organic compounds

APPENDIX A

NPI SUBSTANCES RELEVANT TO FOSSIL FUEL ELECTRIC POWER GENERATION

MINOR ORGANIC AIR EMISSIONS ESTIMATION FOR COAL, NATURAL GAS AND OIL COMBUSTION IN STEAM CYCLE PLANT

Table A-1 indicates the NPI listed substances that are relevant to the fossil fuel electric power generation industry.

Table A-1. **NPI Substances Relevant to Fossil Fuel Electric Power Generation [Identified as bolded]**

prefix	COLUMN 1 SUBSTANCE	COLUMN 2 CASR No.	COLUMN 3 THRESHOLD CATEGORY	COLUMN 4 THRESHOLD
	Acetaldehyde	75-07-0	1	10 tonnes per year
	Acetic acid (ethanoic acid)	64-19-7	1	10 tonnes per year
	Acetone*	67-64-1	1	10 tonnes per year
	Acetonitrile	75-05-8	1	10 tonnes per year
	Acrylamide	79-06-1	1	10 tonnes per year
	Acrylic acid	79-10-7	1	10 tonnes per year
	Acrylonitrile (2-propenenitrile)	107-13-1	1	10 tonnes per year
	Ammonia (total)	**N/A**	**1**	**10 tonnes per year**
	Aniline (benzenamine)	62-53-3	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 or 60,000 megawatt hours, or rated at 20 megawatts**
	Benzene*	**71-43-2**	**1**	**10 tonnes per year**
	Benzene hexachloro- (HCB)	608-73-1	1	10 tonnes per year
	Beryllium & compounds	**7440-41-7**	**1**	**10 tonnes per year**
			2b	**2,000 tonnes per year, or or 60,000 megawatt hours, or rated at 20 megawatts**
	Biphenyl (1,1-biphenyl)	92-52-4	1	10 tonnes per year
	Boron & compounds	**7440-42-8**	**1**	**10 tonnes per year**
1,3-	Butadiene (vinyl ethylene)*	106-99-0	1	10 tonnes per year
	Cadmium & compounds*	**7440-43-9**	**1**	**10 tonnes per year**
			2b	**2,000 tonnes per year, or or 60,000 megawatt hours, or rated at 20 megawatts**
	Carbon disulfide	75-15-0	1	10 tonnes per year
	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**
	Chlorine dioxide	10049-04-4	1	10 tonnes per year
	Chloroethane (ethyl chloride)	75-00-3	1	10 tonnes per year
	Chloroform (trichloromethane)	67-66-3	1	10 tonnes per year
	Chlorophenols (di, tri, tetra)	N/A	1	10 tonnes per year
	Chromium (III) compounds	**7440-47-3**	**1**	**10 tonnes per year**
			2b	**2,000 tonnes per year, or 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 or 60,000 megawatt hours, or rated at 20 megawatts**

prefix	SUBSTANCE (COLUMN 1)	CASR No. (COLUMN 2)	THRESHOLD CATEGORY (COLUMN 3)	THRESHOLD (COLUMN 4)
	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 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
1,2-	Dibromoethane*	106-93-4	1	10 tonnes per year
	Dibutyl phthalate	84-74-2	1	10 tonnes per year
1,2-	Dichloroethane	107-06-2	1	10 tonnes per year
	Dichloromethane*	**75-09-2**	**1**	**10 tonnes per year**
	Ethanol	64-17-5	1	10 tonnes per year
2-	Ethoxyethanol*	110-80-5	1	10 tonnes per year
2-	Ethoxyethanol acetate*	111-15-9	1	10 tonnes per year
	Ethyl acetate	141-78-6	1	10 tonnes per year
	Ethyl butyl ketone	106-35-4	1	10 tonnes per year
	Ethylbenzene	100-41-4	1	10 tonnes per year
	Ethylene glycol (1,2-ethanediol)*	107-21-1	1	10 tonnes per year
	Ethylene oxide	72-21-8	1	10 tonnes per year
	Di-(2-Ethylhexyl) phthalate (DEHP)	117-81-7	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**
	Glutaraldehyde*	111-30-8	1	10 tonnes per year
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**
	Hydrogen sulfide	7783-06-4	1	10 tonnes per year
	Lead & compounds*	**7439-92-1**	**1**	**10 tonnes per year**
			2b	**2,000 tonnes per year, or 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 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 or 60,000 megawatt hours, or rated at 20 megawatts**
	Methanol*	67-56-1	1	10 tonnes per year
2-	Methoxyethanol	109-86-4	1	10 tonnes per year
2-	Methoxyethanol acetate	110-49-6	1	10 tonnes per year
	Methyl ethyl ketone*	78-93-3	1	10 tonnes per year
	Methyl isobutyl ketone*	108-10-1	1	10 tonnes per year
	Methyl methacrylate*	80-62-6	1	10 tonnes per year
4,4-	Methylene bis 2,4 aniline (MOCA)	101-14-4	1	10 tonnes per year

Table A-1.   NPI Substances Relevant to Fossil Fuel Electric Power Generation [Identified as bolded] cont'

prefix	COLUMN 1 SUBSTANCE	COLUMN 2 CASR No.	COLUMN 3 THRESHOLD CATEGORY	COLUMN 4 THRESHOLD
	Methylenebis (phenylisocyanate)	101-68-8	1	10 tonnes per year
	Nickel & compounds	**7440-02-0**	**1**	**10 tonnes per year**
			2b	**2,000 tonnes per year, or 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 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 or 60,000 megawatt hours, or rated at 20 megawatts
	Nitric acid	7697-37-2	1	10 tonnes per year
	Organo-tin compounds	N/A	1	10 tonnes per year
	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**
	Phenol	108-95-2	1	10 tonnes per year
	Phosphoric acid	7664-38-2	1	10 tonnes per year
	Polychlorinated dioxins and furans	**N/A**	**2b**	**2,000 tonnes per year, or 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**
1,1,1,2-	Tetrachloroethane	630-20-6	1	10 tonnes per year
	Tetrachloroethylene *	**127-18-4**	**1**	**10 tonnes per year**
	Toluene (methylbenzene)*	108-88-3	1	10 tonnes per year
	Toluene-2,4-diisocyanate *	584-84-9	1	10 tonnes per year
	Total Nitrogen*	**N/A**	**3**	**15 tonnes per year**
	Total Phosphorus*	**N/A**	**3**	**3 tonnes per year**

Table A-1. **NPI Substances Relevant to Fossil Fuel Electric Power Generation [Identified as bolded] cont'**

prefix	COLUMN 1 SUBSTANCE	COLUMN 2 CASR No.	COLUMN 3 THRESHOLD CATEGORY	COLUMN 4 THRESHOLD
	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 1ßtonne per hour**
1,1,2-	Trichloroethane	79-00-5	1	10 tonnes per year
	Trichoroethylene*	**79-01-6**	**1**	**10 tonnes per year**
	Vinyl Chloride Monomer	75-01-4	1	10 tonnes per year
	Xylenes (individual or mixed isomers)*	1330-20-7	1	10 tonnes per year
	Zinc and compounds	**7440-66-6**	**1**	**10 tonnes per year**

Reference: Table *2 National Environment Protection Measure for the National Pollutant Inventory* NEPC, 1998

Note
* Included in Table 1 of the NEPM and require reporting in 1998/99 and 1999/2000
Ammonia water emissions
Benzene for brown coal combustion
Chlorine water emissions
Cyanide for black and brown coal combustion
Dichloromethane degreasing
Formaldehyde For gas turbines using natural gas and SCR
n-Hexane for natural gas/steam cycle
Tetrachloroethylene degreasing
Trichloroethylene degreasing

AIR EMISSION ESTIMATES FOR MINOR ORGANIC SUBSTANCES AND CYANIDE FROM FOSSIL FUEL ELECTRIC POWER GENERATION

The following tables indicate air emissions of minor organics and cyanide (category 1 substances) for coal, natural gas and oil combustion in steam cycle plant. Many of the organics do not have emission factors since they are not generally products of combustion. For organics that do have emission factors, an estimate of the emissions from the largest single Australian facility, or the total Australian production for fossil fuel electricity production are estimated. Hence, the emission factor tables in the Manual only include those organics that are likely to be emitted at a level greater than the threshold value.

Table A-2 contains emission factors for miscellaneous organic substances that may originate from the combustion of black and brown coal to generate electricity. Many of these substances would be in very small quantities in the exhaust gases, due to the combustion processes and input fuel. Hence, the data for emission factors is less comprehensive compared to the common emissions such as oxides of nitrogen.

Only substances that are likely to exceed the 10 tonne per year threshold are included in the recommended emission factors for black coal and brown coal.

The emissions estimates are based on the largest Australian power station sites utilising black and brown coals. The largest Australian power stations utilising black coal are Eraring and Bayswater, located in NSW. These power stations use between 5 and 6 million tonnes of coal per year. In estimating the emissions, a conservative assumption of 10 million tonnes per year black coal use has been adopted.

For brown coal, the largest single facility is Loy Yang Power, located in Victoria. This site uses an average of approximately 20 million tonnes of brown coal per year. The total emission estimated included in Table A-2 assumes a consumption of 25 million tonnes per year.

Table A-2 Miscellaneous Organic Substances: Emission Factors & Largest Single Site Emissions (Black Coal and Brown Coal Combustion for Electricity Generation)

SUBSTANCE	EMISSION FACTOR kg/tonne[a]	MAXIMUM SITE EMISSIONS FOR 1996[b] tonnes	
		Black coal	brown coal
Acetaldehyde	$2.9 * 10^{-4}$	2.9	7.2
Acetic acid (ethanoic acid)	ND		
Acetone*	ND		
Acetonitrile	ND		
Acrylamide	ND		
Acrylic acid	ND		
Acrylonitrile (2-propenenitrile)	ND		
Aniline (benzenamine)	ND		
Benzene*	$6.5 * 10^{-4}$	6.5	16.3
Benzene hexachloro- (HCB)	ND		
Biphenyl (1,1-biphenyl)	ND		
1,3 Butadiene (vinyl ethylene)*	ND		
Carbon disulfide	$6.5 * 10^{-5}$	0.65	1.6
Chloroethane (ethyl chloride)	ND		
Chloroform (trichloromethane)	$3 * 10^{-5}$	0.3	0.8
Chlorophenols (di, tri, tetra)	ND		
Cumene (1-methylethylbenzene)	$2.7 * 10^{-6}$	0.03	0.05
Cyanide (inorganic) compounds*	$1.3 * 10^{-3}$	13	32.5
Cyclohexane	ND		
1,2- Dibromoethane*	ND		
Dibutyl phthalate[c]	$2.8 * 10^{-5}$	0.3	0.7
1,2- Dichloroethane	ND		
Dichloromethane*	ND		
Ethanol	ND		
2-Ethoxyethanol*	ND		
2-Ethoxyethanol acetate*	ND		
Ethyl acetate	ND		
Ethyl butyl ketone	ND		
Ethylbenzene	$4.7 * 10^{-5}$	0.5	1.2
Ethylene glycol (1,2-ethanediol)*	ND		
Ethylene oxide	ND		
Di-(2-Ethylhexyl)phthalate (DEHP)	$3.7 * 10^{-5}$	0.4	0.9
Formaldehyde (methyl aldehyde)	$1.2 * 10^{-4}$	1.2	3.0
Glutaraldehyde*	ND		
n- Hexane	$3.4 * 10^{-5}$	0.3	0.9
Methanol*	ND		
2- Methoxyethanol	ND		
2- Methoxyethanol acetate	ND		
Methyl ethyl ketone*	$2 * 10^{-4}$	2	5.0
Methyl isobutyl ketone*[c]	$8.0 * 10^{-5}$	0.8	2.0
Methyl methacrylate*	$1 * 10^{-5}$	0.1	0.24

Table A-2 Miscellaneous Organic Substances: Emission Factors & Largest Single Site Emissions (Black Coal and Brown Coal Combustion for Electricity Generation) cont'

SUBSTANCE	EMISSION FACTOR kg/tonne[a]	MAXIMUM SITE EMISSIONS FOR 1996[b] tonnes	
		Black coal	brown coal
4,4- Methylene bis 2,4 aniline (MOCA)	ND		
Methylenebis (phenylisocyanate)	ND		
Phenol	$8 * 10^{-6}$	0.1	0.19
Styrene (ethenylbenzene)	$1.3 * 10^{-5}$	0.1	0.33
1,1,1,2 Tetrachloroethane	ND		
Tetrachloroethylene*	$2.2 * 10^{-5}$	0.2	0.57
Toluene (methylbenzene)*	$1.2 * 10^{-4}$	1.2	3.0
Toluene-2,4-diisocyanate*	ND		
1,1,2- Trichloroethane	Not detected		
Trichloroethylene*[c]	$3.1 * 10^{-5}$	0.31	0.76
Vinyl Chloride Monomer	Not detected		
Xylenes (individual or mixed isomers)*	$1.9 * 10^{-5}$	0.2	0.47

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 1.1-13)

Profile of the Fossil Fuel Electric Power Generation Industry, USEPA Office of Compliance Sector Notebook Project, 1997

Notes:

        Extracted from Table 2 of the NEPM

ND   No data available

        Not detected: Substance sampled for but not detected

*   Included in Table 1 of the NEPM

a   Emission factors derived from Table 1.1-13, AP-42 (1996)

b   Based on a black coal and brown coal consumptions for electricity production (at a single site) of 10 million tonnes and 25 million tonnes respectively.

c   Derived from average emission factors for coal assuming a black coal heating value of 23MJ/kg (Reference*: Profile of the Fossil Fuel Electric Power Generation Industry*, USEPA Office of Compliance Sector Notebook Project, 1997)

For the combustion of natural gas in steam plants, the total emissions are based on a total Australian natural gas consumption of 121.7 PJ for electricity generation during 1996 (*Electricity Australia 1997*, ESAA)

Table A-3 Miscellaneous Organic Substances: Emission Factors & Total Emissions (Natural Gas Combustion for Electricity Generation)

SUBSTANCE	EMISSION FACTOR Tonne/PJ[a]	TOTAL EMISSIONS FOR 1996 tonnes
Acetaldehyde	ND	
Acetic acid (ethanoic acid)	ND	
Acetone*	ND	
Acetonitrile	ND	
Acrylamide	ND	
Acrylic acid	ND	
Acrylonitrile (2-propenenitrile)	ND	
Aniline (benzenamine)	ND	
Benzene*	8.8×10^{-4}	0.11
Benzene hexachloro- (HCB)	ND	
Biphenyl (1,1-biphenyl)	ND	
1,3 Butadiene (vinyl ethylene)*	ND	
Carbon disulfide	ND	
Chloroethane (ethyl chloride)	ND	
Chloroform (trichloromethane)	ND	
Chlorophenols (di, tri, tetra)	ND	
Cumene (1-methylethylbenzene)	ND	
Cyanide (inorganic) compounds*	ND	
Cyclohexane	ND	
1,2- Dibromoethane*	ND	
Dibutyl phthalate	ND	
1,2- Dichloroethane	ND	
Dichloromethane*	ND	
Ethanol	ND	
2-Ethoxyethanol*	ND	
2-Ethoxyethanol acetate*	ND	
Ethyl acetate	ND	
Ethyl butyl ketone	ND	
Ethylbenzene	ND	
Ethylene glycol (1,2-ethanediol)*	ND	
Ethylene oxide	ND	
Di-(2-Ethylhexyl)phthalate (DEHP)	ND	
Formaldehyde (methyl aldehyde)	3.2×10^{-2}	3.9
Glutaraldehyde*	ND	
n- Hexane	0.76	92.5
Methanol*	ND	
2- Methoxyethanol	ND	
2- Methoxyethanol acetate	ND	

Table A-3   Miscellaneous Organic Substances: Emission Factors & Total Emissions (Natural Gas Combustion for Electricity Generation)

SUBSTANCE	EMISSION FACTOR Tonne/PJ[a]	TOTAL EMISSIONS FOR 1996 tonnes
Methyl ethyl ketone*	ND	
Methyl isobutyl ketone*	ND	
Methyl methacrylate*	ND	
4,4- Methylene bis 2,4 aniline (MOCA)	ND	
Methylenebis (phenylisocyanate)	ND	
Phenol	ND	
Styrene (ethenylbenzene)	ND	
1,1,1,2 Tetrachloroethane	ND	
Tetrachloroethylene*	ND	
Toluene (methylbenzene)*	$1.4 * 10^{-3}$	0.2
Toluene-2,4-diisocyanate*	ND	
1,1,2- Trichloroethane	ND	
Trichloroethylene*	ND	
Vinyl Chloride Monomer	ND	
Xylenes (individual or mixed isomers)*	ND	

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 1.4-3)

Notes:
*   Included in Table 1 of the NEPM
ND   Not data available
a   Derived from Table 1.4-3, AP-42 (1996)

For oil combustion in steam plants, the total emissions are based on a total fuel oil used in 1996 for electricity generation of 73,851 tonnes (82,000 kL) *(Electricity Australia 1997,* ESAA*)*

Table A-4   Miscellaneous Organic Substances: Emission Factors & Total Emissions (Fuel Oil Combustion for Electricity Generation)

SUBSTANCE	EMISSION FACTOR kg/10^3 L[a]	TOTAL EMISSIONS FOR 1996 tonnes
Acetaldehyde[b]	$1.4 * 10^{-4}$	0.01
Acetic acid (ethanoic acid)	ND	
Acetone*	ND	
Acetonitrile	ND	
Acrylamide	ND	
Acrylic acid	ND	
Acrylonitrile (2-propenenitrile)	ND	
Aniline (benzenamine)	ND	
Benzene*	$2.5 * 10^{-5}$	$2 * 10^{-3}$
Benzene hexachloro- (HCB)	ND	
Biphenyl (1,1-biphenyl)	ND	
1,3 Butadiene (vinyl ethylene)*	ND	
Carbon disulfide	ND	
Chloroethane (ethyl chloride)	ND	
Chloroform (trichloromethane)	ND	
Chlorophenols (di, tri, tetra)	ND	
Cumene (1-methylethylbenzene)	ND	
Cyanide (inorganic) compounds*	ND	
Cyclohexane	ND	
1,2- Dibromoethane*	ND	
Dibutyl phthalate	ND	
1,2- Dichloroethane	ND	
Dichloromethane*	ND	
Ethanol	ND	
2-Ethoxyethanol*	ND	
2-Ethoxyethanol acetate*	ND	
Ethyl acetate	ND	
Ethyl butyl ketone	ND	
Ethylbenzene	$7.6 * 10^{-6}$	$6.2 * 10^{-4}$
Ethylene glycol (1,2-ethanediol)*	ND	
Ethylene oxide	ND	
Di-(2-Ethylhexyl)phthalate (DEHP)	ND	
Formaldehyde (methyl aldehyde)	$4 * 10^{-3}$	0.33
Glutaraldehyde*	ND	
n- Hexane	ND	
Methanol*	ND	
2- Methoxyethanol	ND	
2- Methoxyethanol acetate	ND	

Table A-4 Miscellaneous Organic Substances: Emission Factors & Total Emissions (Fuel Oil Combustion for Electricity Generation) cont'

SUBSTANCE	EMISSION FACTOR $kg/10^3 L^a$	TOTAL EMISSIONS FOR 1996 tonnes
Methyl ethyl ketone*	ND	
Methyl isobutyl ketone*	ND	
Methyl methacrylate*	ND	
4,4- Methylene bis 2,4 aniline (MOCA)	ND	
Methylenebis (phenylisocyanate)	ND	
Phenol[b]	$4.1 * 10^{-4}$	0.03
Styrene (ethenylbenzene)	ND	
1,1,1,2 Tetrachloroethane	ND	
Tetrachloroethylene*[b]	$9.1 * 10^{-6}$	$7 * 10^{-4}$
Toluene (methylbenzene)*	$7.4 * 10^{-4}$	$6 * 10^{-2}$
Toluene-2,4-diisocyanate*	ND	
1,1,2- Trichloroethane	ND	
Trichloroethylene*	ND	
Vinyl Chloride Monomer	ND	
Xylenes (individual or mixed isomers)*	$1.3 * 10^{-5}$	$1 * 10^{-3}$

Compilation of Air Emission Factors, AP-42, Fifth edition, Volume 1: Stationary Point and Area Sources, 1996 (Table 1.3.-8)

Profile of the Fossil Fuel Electric Power Generation Industry, USEPA Office of Compliance Sector Notebook Project, 1997

Notes:
*   Included in Table 1 of the NEPM
ND   Not data available
a   Derived from Table 1.3-8, AP-42 (1996)
b   Derived from emission factors assuming a heating value of 39.7 MJ/L (Reference: *Profile of the Fossil Fuel Electric Power Generation Industry*, USEPA   Office of Compliance Sector Notebook Project, 1997)

APPENDIX B

AUSTRALIAN COAL PROPERTIES

AUSTRALIAN COAL PROPERTIES

The following Tables list properties of coals commonly used for the fossil fuel electricity generation industry. The tables include a range of properties, particularly for trace elements, indicating the heterogeneous nature of coal.

These properties may be used to estimate emissions of trace elements in the absence of better data.

Table B-1.   Indicative Coal Properties for Black Coals used in the Electricity Generation Industry

COAL CONSTITUENT (as fired basis)	COAL			
	NSW[a]	QUEENSLAND[a]	WESTERN AUSTRALIA[b]	
	Range	Range	low	high
% Carbon	57.1 - 64.5	53.2 - 80.5		
% Hydrogen	3.54 - 4.1	2.6 - 6.5		
% Nitrogen	1.15 - 1.5	0.8 - 1.5		
% Sulfur	0.34 - 0.55	0.15 - 0.75		
% Moisture	1.9 - 7.7	5.0 - 19.0		
% Ash	17.4 - 25.8	11.7 - 15.3		
OTHER ELEMENTS (mg/kg)[c]				
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[d]	7 - 23	9.8 - 28.0	1	10
Chromium III	ND	ND	ND	ND
Chromium VI	ND	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	ND
Manganese	5 - 360	7.1 - 438	<1	43
Mercury	0.02 - 0.11	0.01 - 0.1	ND	ND
Nickel	5 - 50	5.1 - 16.0	2	22
Selenium	<1 - 2	0.12 - 0.53	ND	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		

Notes

  trace elements on a dry or air dried basis
ND no data available
< less than indicates the limit of detection for the element for the technique applied
a personal communication with NSW and Queensland electricity generating companies
b Reference: Swaine D *Trace Elements in Coal* (Butterworth, 1990)
c includes compounds
d chromium (III & VI)

Table B-2   Indicative Coal Properties for Brown Coals used in the Electricity Generation Industry

COAL CONSTITUENT	COAL	
	VICTORIA	SOUTH AUSTRALIA[a]
	Range	Range
% Carbon (db)	67.5 - 69.2	50.4
% Hydrogen (db)	4.8 - 4.9	2.9
% Nitrogen (db)	0.57 - 0.60	1.1
% Sulfur (db)	0.29 - 0.38	0.7
% Moisture (ar)	61.3 - 66.5	28.0
% Ash (db)	1.3 - 3.0	27.8
OTHER ELEMENTS (mg/kg, db)[b]		
Antimony	<0.02 - 0.02	0.3 - 2.6
Arsenic	0.05 - 0.2	0.7 - 6
Beryllium	<0.05 - 0.26	<1 - 1.5
Boron	3 - 24	40 - 300
Cadmium	0.01 - 0.03	0.1 - 0.11
Chlorine	0.06 - 0.08	500 - 17,000
Chromium[c]	0.3 - 3.9	5 - 80
Chromium III	ND	ND
Chromium VI	ND	ND
Cobalt	0.2 - 0.9	<2 - 25
Copper	0.3 - 2.4	3 - 60
Fluoride	8 - 22	191 - 367
Lead	0.3 - 1.9	<2 - 50
Magnesium	0.05 - 0.35	0.29 - 0.45
Manganese	0.7 - 40	<2 - 500
Mercury	0.06 - 0.34	0.12 - 0.27
Nickel	1.2 - 3.8	4 - 60
Selenium	0.3 - 0.6	<0.5 - 1
Zinc	1.3 - 20	15 - 200
HEAT VALUE		
Higher Heating Value (MJ/kg)	8.76 - 10.2	

Notes:
ND   no data available
db   dry basis
ar   as received
a   Reference: Swaine D *Trace Elements in Coal* (Butterworth, 1990)
b   includes compounds
c   chromium (III & VI)