LIFECYCLE EMISSIONS AND ENERGY ANALYSIS
OF
LNG, OIL AND COAL

Final Report to

WOODSIDE PETROLEUM Pty Ltd

COMMERCIAL - IN - CONFIDENCE

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Executive Summary

Lifecycle analyses (including uncertainties) have been performed on greenhouse gas emissions and useful energy from three fuels used to generate electricity in Japan.

The cases examined are:

1) Coal from the Hunter Valley, Australia.
2) Liquefied natural gas from the North West Shelf, Australia.
3) Oil from the Middle East.

The results provide:

a) the greenhouse gas emissions (in CO_2 equivalent units) to land 1 tonne of fuel for electricity generation in Japan;
b) the greenhouse gas emissions (in CO_2 equivalent units) from the use of 1 tonne of fuel in electricity generation in Japan and (including those emissions in (a);
c) the greenhouse gas emissions per megawatt hour of electricity generated with the fuel.

Gases	Coal	LNG	Oil
a) kg CO_2 equivalent/tonne fuel landed	227	838	690
b) kg CO_2 equivalent/tonne of fuel used in Japan	2,600	3,712	3,870
c) kg CO_2 equivalent/MWh generated	865 ± 18	493 ± 9	728 ± 18

The study shows that over the entire fuel-cycle for the cases evaluated, the use of LNG as a fuel to generate electricity in Japan results in less greenhouse gas emitted to the atmosphere than Australian black coal or Middle East oil used for comparable purposes. The use of coal generates the most emissions. All assumptions used in this analysis are outlined in the body of the report.

For the purposes of this analysis the fuel-cycle can be divided into two components an ‘upstream’ component involving the extraction, production and shipping of the fuel to Japan, and the downstream components which include all emissions in Japan to the point of electricity leaving the power station.

As can be seen from (a) in the table above coal produces the least upstream emissions followed by oil, then LNG. However, the larger part of the total emissions occur downstream. The influence of fuel composition and efficiency of current generating facilities are significant, resulting in fewest emissions associated with LNG followed by Middle East oil, then coal.

The greenhouse gas emissions associated with the raw materials used and the energy expended in the construction of the plant for producing the LNG are shown to be negligible

compared with those associated with the production and consumption of the fuel. This is assumed to be true also for each of the other cases.

The uncertainty analysis presented here gives the 95% confidence limits and shows that differences between the results for the three cases are highly significant.

Uncertainties not contained within the analyses include those arising from Global Warming Potentials (GWPs) and the omission of Volatile Organic Compounds (VOCs) and Carbon Monoxide (CO) in the analysis. Although GWPs have a published uncertainty of ±35%, the influence of this uncertainty on the overall analysis is considered to be negligible. Similarly, inclusion of CO and VOCs in the analysis is considered likely to change the ratio of emissions per MWh between the different fuels by 5% at the most.

These analyses are based on the efficiency of fuel use in electricity generating power plants, and it must be noted that these efficiencies are expected to increase in future, particularly for oil and coal fired power stations. While these changes would diminish the greenhouse gas emission differences between coal, oil and LNG they would not remove them.

1 Introduction

This study has been prepared by CSIRO in response to a brief from Woodside Offshore Petroleum Pty Ltd.

The objective of the study is to evaluate and compare the greenhouse gas emissions and useful energy that arise from the use of Liquefied Natural Gas (LNG), coal and oil. The analysis takes into account the lifecycle emissions and energy budget of LNG from the wellhead to the final use. including shipping and processing and compares these with similar lifecycles for coal and oil. The end-product for this analysis is electricity generation in Japan.

The level of detail involved in the report is intended to be sufficient for the uncertainty in the final indicator (energy or emission per unit mass) to be constrained primarily by the uncertainty in the current knowledge of these emissions. Assumptions are reported and errors identified and quantified.

The greenhouse gases specified in the brief are:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Nitrogen oxide (NO_x)

Where appropriate, greenhouse gas emissions are converted to "CO_2 equivalents" using the 100 year Global Warming Potentials (GWP) from the IPCC "Summary for Policymakers" document, (Houghton et al. 1995) for CH_4 and N_2O, and those from the earlier report for NO_x (Houghton et al. 1990):

Table 1. Relative GWP (weight basis) (from IPCC 1994 and 1990)

Component	GWP Factor
CO_2	1
CH_4	24.5
N_2O	310
NO_x	40

2 Background

Woodside Offshore Petroleum Pty Ltd is the operator of the North West Shelf Gas Project (NWSGP) situated in the north west of Western Australia. The Project comprises Offshore Platforms (North Rankin Alpha, Goodwyn Alpha) exporting natural gas and condensate through a 130 km trunkline to the Onshore Treatment Plant in Karratha. The gas and condensate are then separated, with the gas being exported as Domestic Gas (Domgas) through the 1,700 km Dampier-Perth gas pipeline or liquefied natural gas to Japanese customers.

Woodside produces 7.15 Mt of LNG and 2.5 Mt of condensate per annum from the Onshore Treatment Plant in Karratha, WA.

Most of this is sent to gas and power utilities within Japan, although cargoes have gone to Spain, Turkey and Korea.

The study will use the energy value of the Woodside NWS annual LNG production and the emissions arising thereof.

3 Lifecycle Analyses for LNG, Coal and Oil used for Electricity Generation in Japan

In 1993, 22%, 12% and 19% of Japan's electricity was generated from LNG, coal and oil respectively (World Energy Council, 1995). Japan is dependent on imports for 99.6% of its crude oil needs and of this, 77% came from the Middle East in 1994. Substantial fractions of Japan's 1993 imports of LNG (13%) and coal (55%) came from Australia (World Energy Council, 1995).

Whilst there are many end-uses for oil-derived products in Japan, most of the coal is used for electricity generation (29%) and steel production (51%). Most of the LNG (72%) is consumed for electricity generation (World Energy Council, 1995).

On the basis of the above data on LNG use in Japan, it is considered that electricity generation is the most appropriate scenario to use for estimating of the comparative lifecycle greenhouse gas emissions for coal, oil and LNG imported into Japan. Accordingly, the following three cases have been considered in this study.

Case 1: Production of Australian coal from the upper Hunter Valley and its export from the port of Newcastle to Japan (Yokohama) where it is used for electricity generation in a base load power plant.

Case 2: Production of LNG from the North West Shelf region of WA and its export to Japan where it is used for electricity generation in a base load power plant.

Case 3: Production of crude oil in the Middle East and its export to Japan where it is refined and a fuel oil fraction is used to generate electricity in a base load power plant.

3.1 Methodology

For each case, the greenhouse gas emissions (CO_2, CH_4, N_2O and NO_x) associated with each major stage of the fuel cycle are estimated to give the total emissions associated with producing the fuel and delivering it to Japan. The Global Warming Potentials (GWP) in Table 1 are used to convert the emissions to kg of CO_2 equivalent per tonne of fuel fed to the power station in Japan. The total of these CO_2 equivalent emissions is then added to the corresponding emissions from the power plant to give the full fuel cycle greenhouse gas emissions as kg CO_2 equivalent/megawatt-hour (MWh) of electricity despatched from the power plant in Japan.

For each fuel, a range of electricity generating technologies (each with its own overall thermal efficiency) is available commercially now, or will be commercial in the near future. In order to illustrate the effect of electricity technology selection on the lifecycle greenhouse gas emissions for each type of fuel, the results are presented as plots showing kg CO_2 equivalent per MWh as a function of power plant overall thermal efficiency, with the range of thermal efficiencies and greenhouse gas emissions for each type of technology clearly marked on these figures.

The greenhouse gas emissions associated with the construction and decommissioning of the plant and equipment used in the full fuel cycles have also been considered in this study. Estimating these greenhouse gas emissions is difficult and time-consuming and, as will be shown later, they are clearly negligible compared to those generated from the combustion of the fuel over the operating life of the fuel cycle (assumed to be at least 25 years in this analysis).

3.2 CASE 1: Production and Export of Australian Coal to Japan for Electricity Generation

General Description

A flow diagram of the Case 1 fuel cycle for coal is given in Figure 1.

The coal is assumed to be produced from an open-cut mine located in the upper Hunter Valley region north west of Newcastle, NSW. Many of the existing mines in this area (e.g. Drayton, Bayswater No.2, Lemington, Mount Thorley etc.) are open-cut operations and several major new open-cut mines (e.g. Bengalla, Bayswater No. 3 etc.) are planned (NSW Department of Mineral Resources, 1993).

The coal is mined, crushed and washed at the minesite to generate a steaming coal product which is then transported by rail to the Port Waratah coal loading facility at Newcastle. From here it is transported by bulk sea carrier to Japan where it is used to generate electricity in a base load pulverised-fuel (pf) power plant which is equipped with flue gas desulphurisation (FGD) for SO_2 emission control and selective catalytic reduction (SCR) facilities for NO_x abatement. The effect of using new advanced clean coal power generating technologies on the overall lifecycle greenhouse gas emissions is also considered briefly.

This scenario, which can be considered to be typical of the utilisation of Australian coal in Japan for power generation, is similar to the fuel cycle studied in the Full Fuel Cycle analysis recently completed by the International Energy Agency (IEA) Greenhouse Gas R&D Programme, and general summaries of the results of this study have been published (Audus, 1996; Audus and Saroff, 1994; IEA Greenhouse Gas R&D Programme, 1995). The major difference between the scenario used in this analysis and that used for the coal case in the IEA study is that the IEA study, was based on using the coal in the same type of power plant located in the Netherlands, rather than in Japan. Much of the information in the IEA study is directly relevant to the current analysis and it has been used, after appropriate modification, to account for the different power plant locations, to generate the lifecycle greenhouse gas emission estimates presented here for Case 1. Unfortunately, the detailed reports for the IEA study are not public documents and are only available to Members of the Programme. Where information from these reports, or from other unpublished IEA data, has been used in the current study it has been referred to as “IEA Greenhouse Gas R&D Programme, in-house data”.

The factors and assumptions used to generate the greenhouse gas emissions estimates for Case 1 are now presented and discussed.

<u>Assumptions and Factors Used to Estimate Greenhouse Gas Emissions</u>

Coal mining and extraction

It is assumed that the coal comes from an existing open-cut coal mine in the Muswellbrook region of the upper Hunter Valley coalfield north west of Newcastle, NSW. The greenhouse gas emissions from this stage of the fuel cycle come mainly from two sources, namely:

(a) the fuel and energy used by the mining equipment, and

(b) the coal seam gas which, in the case of open-cut mining, is unavoidably released into the atmosphere during mining.

With respect to (a), it is assumed that diesel-powered equipment is used for coal and overburden excavation with an estimated consumption of industrial diesel oil (IDO) of 8 kg/tonne coal produced (IEA Greenhouse Gas R&D Programme, in-house data). Emissions have been based on the IDO containing 87 wt% carbon and 0.1 wt% sulphur. The emissions of CH_4, N_2O and NO_x are derived from the Australian emission factors for diesel transport of 0.09, 0.03 and 20.6 kg/tonne of CO_2 respectively.

The other energy consumed by the coal mine is electricity for conveyor belts and coal crushing equipment. In-house estimates by CSIRO indicate that this energy requirement is relatively minor at around 1 kWh_e per tonne of raw coal. The greenhouse gas emissions associated with the generation of electricity consumed within Australia are estimated on the basis that the electricity is generated from coal at 37% overall thermal efficiency, a typical figure for the large base-load coal-fired power stations in NSW. The emissions of non-CO_2 greenhouse gases associated with the generation of electricity consumed in coal mining and preparation have been taken as those recommended for pulverised coal wall-fired utility boilers (Intergovernmental Panel on Climate Change (IPCC), 1994) and are 0.6, 0.8 and 461 kg/TJ of energy input for CH_4, N_2O and NO_x respectively.

With respect to (b) above, coal seam gas emissions from coal mining activities depend on, amongst many other things, the depth of the coal seam below the surface. Shallow coal seams, amenable to open-cut mining, generally have much lower gas content than the deep coal seams which are only accessible by underground mining methods. However, unlike the coal seam gas from underground mines, which can in some cases be recovered and combusted for useful energy recovery, as well as lowering the GWP effect though conversion of the methane content to CO_2, the methane in gas from open-cut mined coal is unavoidably emitted to the atmosphere.

The IEA study used a figure for Drayton coal of 1 Nm^3 of methane/tonne of coal mined. However, methane flux measurements from Hunter Valley open-cut mines (including the Drayton mine) (Williams et al., 1993; Williams and Saghafi, 1993), suggest that this is an underestimate and that a more realistic figure would be 3-3.5 Nm^3/tonne of coal mined, and 3.3 Nm^3/tonne has been used in this estimate. The data of Williams et al. (1993) indicate that the residual gas content in the coal, after it has been mined, is negligible. Therefore, it is assumed that the above figure of 3.3 Nm^3/tonne (assumed to consist of 90 mol% CH_4 and 10 mol% CO_2) is totally released during mining and there is no subsequent release of gas from the coal during its preparation and transport to Japan.

Coal preparation

Most, but not all, of Australia's exported steaming and coking coals are washed to reduce their mineral matter levels prior to shipment from the mine. This is done to meet end-user specifications and to reduce transport costs per unit of deliverable energy.

Of the 46 Mt of raw coal produced from the 16 operating mines in the Hunter Valley in 1991-92, 34.6 Mt were processed in washeries to generate 25.2 Mt of saleable product at an average yield of 0.722 tonnes of saleable coal per tonne of raw coal produced (NSW Department of Mineral Resources, 1993). In the base case scenario, which includes coal preparation, this yield figure is used.

All energy consumption within the coal washery is in the form of electricity, and in-house estimates by CSIRO Division of Coal and Energy Technology of the energy consumption are 2.7 kWh/tonne product coal. The coal yield factor given above has been used to adjust the energy required for coal mining and the coal seam gas release to bring these on a per tonne of coal shipped to Japan basis. The analysis of the coal shipped to Japan is taken as that used in the IEA study (IEA Greenhouse Gas R&D Programme, in-house data) and is given in Table 2 below.

Table 2. Analysis of Australian Coal Shipped to Japan in Case 1

Proximate Analysis	(wt%)
- dry, ash-free (daf) coal	78.3
- ash	12.2
- moisture	9.5
Ultimate Analysis (daf basis)	(wt%)
- carbon	82.5
- hydrogen	5.6
- nitrogen	1.8
- sulphur	1.1
- oxygen (diff)	9.0
Gross Calorific Value (MJ/kg as shipped)	27.06
Net Calorific Value (MJ/kg as shipped)	25.87

The same coal analysis has been used to calculate the CO_2 emissions associated with the production of the electricity required for coal mining and preparation.

The mining and preparation of coal exposes carbonaceous shales and generates washery rejects. Both these materials contain substantial amounts of organic carbon which, if left exposed to the atmosphere, will be converted to CO_2 over time through processes such as low temperature oxidation and spontaneous combustion. Further work needs to be done to quantify the significance of these phenomena and efforts in this area are continuing (Bainbridge et al., 1994). In this analysis no greenhouse gas emissions from either the carbonaceous shale spoil dumps or washery reject material have been included. The coal washery is assumed to be located at the mine site with all spoil and washery reject material being returned to the open-cut for disposal.

Coal transport from mine to Newcastle

The fuel consumption for the rail transport of coal in the UK has been quoted as 0.48 MJ/tonne-km (Boustead and Hancock, 1979) for a diesel train working in a closed circuit (i.e. fully loaded forward trip and empty return trip). A comparable figure given for the USA is 0.25 MJ/tonne-km (Khoury, 1981). More recent data for Australian conditions have been published by the Bureau of Transport and Communications Economics (BTCE) (BTCE, 1995) showing the automotive diesel oil (ADO) consumption for government bulk freight is 0.254 MJ/tonne-km, and this figure has been used in this analysis. The emission factors for rail transport using ADO as fuel are (BTCE, 1995) 69.7, 0.006, 0.002 and 1.71 grams/MJ for CO_2, CH_4, N_2O and NO_x respectively.

The distance of the Drayton colliery from the Port Waratah Coal Loader is 120 km (NSW Dept of Mineral Resources, 1993) and it is assumed that the rail transport of coal is conducted in a dedicated train.

Shipment of coal from Newcastle to Japan

In the IEA study, the fuel consumption for the marine transport of coal in a 100,000 tonne vessel was taken as 0.05 MJ/tonne-km based on the data from Boustead and Hancock (Boustead and Hancock, 1979). This figure is close to Drewry's bulk ships fuel intensity figure of 0.06 MJ/tonne-km (BTCE, 1995) for non-dedicated ocean transport (i.e. the carrier does not return specifically to Australia to reload another shipment). Since most Australian export coal is transported in non-dedicated carriers, a fuel intensity figure of 0.06 MJ/tonne-km has been used in this analysis. The emission factors for bunker fuel oil for international shipping from Australia are 73.3, 0.003, 0.002 and 1.52 grams/MJ for CO_2, CH_4, N_2O and NO_x respectively (BTCE, 1995).

The shipping distance from Newcastle to Nagoya is 7968 km (Mannini, 1989). On this basis, the distance from Newcastle to Yokohama would be approximately 8,100 km and this is the value used here to estimate the total emissions for the ocean transport of coal from Australia to Japan.

Electricity generation in Japan

The power plant is based on that assumed in the IEA study and consists of a supercritical steam Rankine cycle plant equipped with selective catalytic reduction (SCR) for NO_x abatement and flue gas desulphurisation (FGD) for the control of sulphur oxide emissions. The SCR unit removes 90% of the NO_x whilst the FGD plant removes 95% of the SO_2 in the power station flue gas.

In the IEA study, the overall thermal efficiency of the power plant system was taken as 45.6% (net calorific value basis) or 43.6% (gross calorific value basis). The plant is assumed to be located in the Netherlands, with cooling water available at 12°C. Since the overall thermal efficiency of the power plant is very dependent on cooling water temperature (the lower the temperature the higher the efficiency), this type of efficiency could not be attained in Japan where the average water temperature is likely to be somewhat greater.

On this basis, a thermal efficiency of 40% (gross calorific value basis) or 41.8% (net calorific value basis) has been taken as the base case for the power plant in Japan, and the effect of varying this efficiency on the overall lifecycle emissions has been considered.

The estimate of lifecycle greenhouse gas emissions also includes the CO_2 generated by the decomposition of the limestone used in the FGD section of the power plant.

The estimate assumes that 99% of the carbon in the coal is combusted to CO_2 in the power plant, the remaining 1% of carbon is retained within the ash residue from the boiler.

Results of the Estimate

The detailed emissions inventory for the base case of Case 1 is given in Table 3.

The emissions of each component of stages 1 to 5 of Table 3 are used to give total emissions in kg/tonne of coal fed to the power station. These figures are then converted to kg of CO_2 equivalent using the GWP factors given in Table 1. This results in a grand total of 226.9 kg of CO_2 equivalent /tonne of coal fed to the power station. The combustion of one tonne of coal in the power station produces greenhouse gas emissions of 2,373.6 kg of CO_2 equivalent to give the total lifecycle emissions of 226.9 + 2,372.6 - 2,600 kg of CO_2 equivalent per tonne of coal fed to the power plant.

Based on the 40% thermal efficiency for power generation assumed here, this equates to a net generation of 3.006 megawatt-hours (MWh) of electricity per tonne of coal feed. This in turn translates to an overall fuel cycle greenhouse gas emission rate of 865 kg CO_2 equivalent per MWh.

It is interesting to note that the greenhouse gas emission from simply combusting the coal in the power plant is 91% of the total fuel cycle emissions. In this case, the emissions from the other stages in the cycle are far less significant.

Effect of Using New Clean Coal Technologies on Lifecycle Emissions

There are new clean coal power generation technologies which are currently at or near the commercial demonstration phase of development. These technologies promise thermal efficiencies which are significantly higher than the figure of 40% (gross calorific value basis) assumed for the base case in this analysis. They include Integrated Gasification - Combined Cycle (IGCC) (with or without hot gas cleaning), Pressurised Fluidised-bed Combustion (PFBC) with an ultra supercritical steam cycle and Integrated Gasification combined with Humid Air Turbines and Fuel Cells.

To indicate how these emerging clean coal power generation technologies can impact on the overall lifecycle greenhouse gas emissions, Figure 2 shows a plot of the CO_2 equivalent of the emissions per MWh as a function of the thermal efficiency of power generation on a gross calorific value basis. The expected thermal efficiency ranges for each of the technologies (Smith, 1993) are also indicated on this plot.

Figure 2 shows that, as expected, the end-use thermal efficiency has a very significant effect on the lifecycle greenhouse gas emissions for coal. For example, the successful development of integrated coal gasification - fuel cell electricity generating technologies promise to reduce the emissions from 865 kg CO_2 equivalent per MWh, incurred with current pulverised coal technology, to around 700 kg CO_2 equivalent per MWh.

Table 3 Greenhouse Gas Emissions for Case 1 - Power Generation in Japan from Australian Coal (Hunter Valley - Open Cut)

Stage in Fuel Cycle	Atmospheric Emissions (kg/tonne coal feed to power station)			
	CO_2	CH_4	N_2O	NO_x
1/ Coal Mine				
• energy for mining (diesel/electricity)	36.5	0.003	0.0011	0.734
• coal seam gas	0.6	2.97	-	-
2/ Coal Preparation				
• energy for preparation (electricity)	2.3	negl.[2]	negl.	0.012
3/ Coal Transport to Newcastle				
• energy for rail transport (diesel)	2.2	negl.	0.0001	0.052
4/ Coal Transport (Newcastle-Japan)				
• energy for shipping (bunker fuel oil)	35.8	0.002	0.0010	0.743
5/ Provision of Lime for FGD[1]				
• CO_2 from limestone decomposition	14.3	-	-	-
6/ Power Generation in Japan				
• emissions in power plant flue gas	2,345.0	-	0.0234	0.504
Total Emissions	**2,436.7**	**2.975**	**0.0256**	**2.045**
GWP Factors	1	24.5	320	40
Total CO_2 Equivalent	**2,436.7**	**73.0**	**8.2**	**81.8**

[1] FGD = flue gas desulfurisation
[2] negl. = negligible

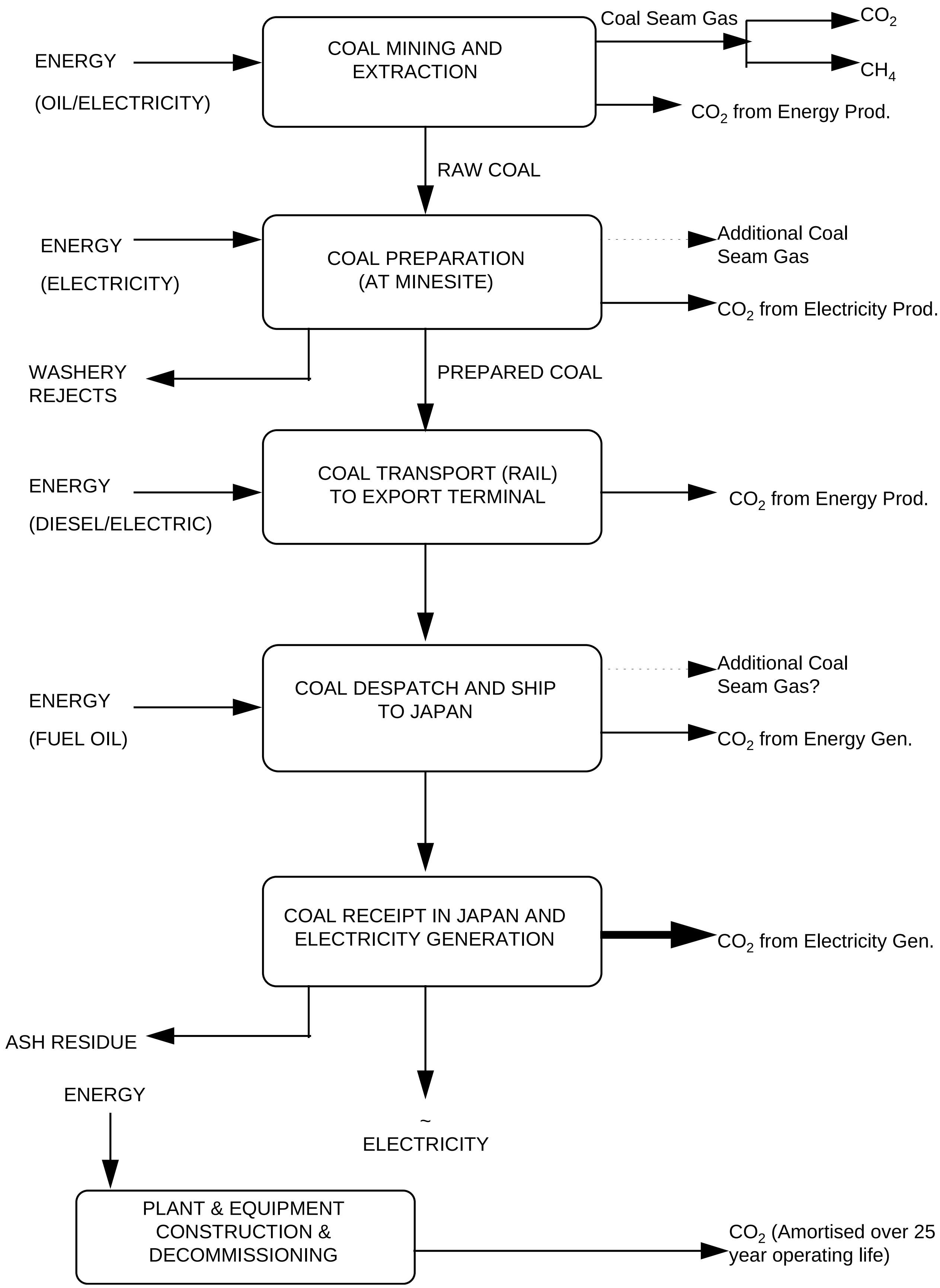

Figure 1 Case 1: Australian coal production - electricity generation in Japan

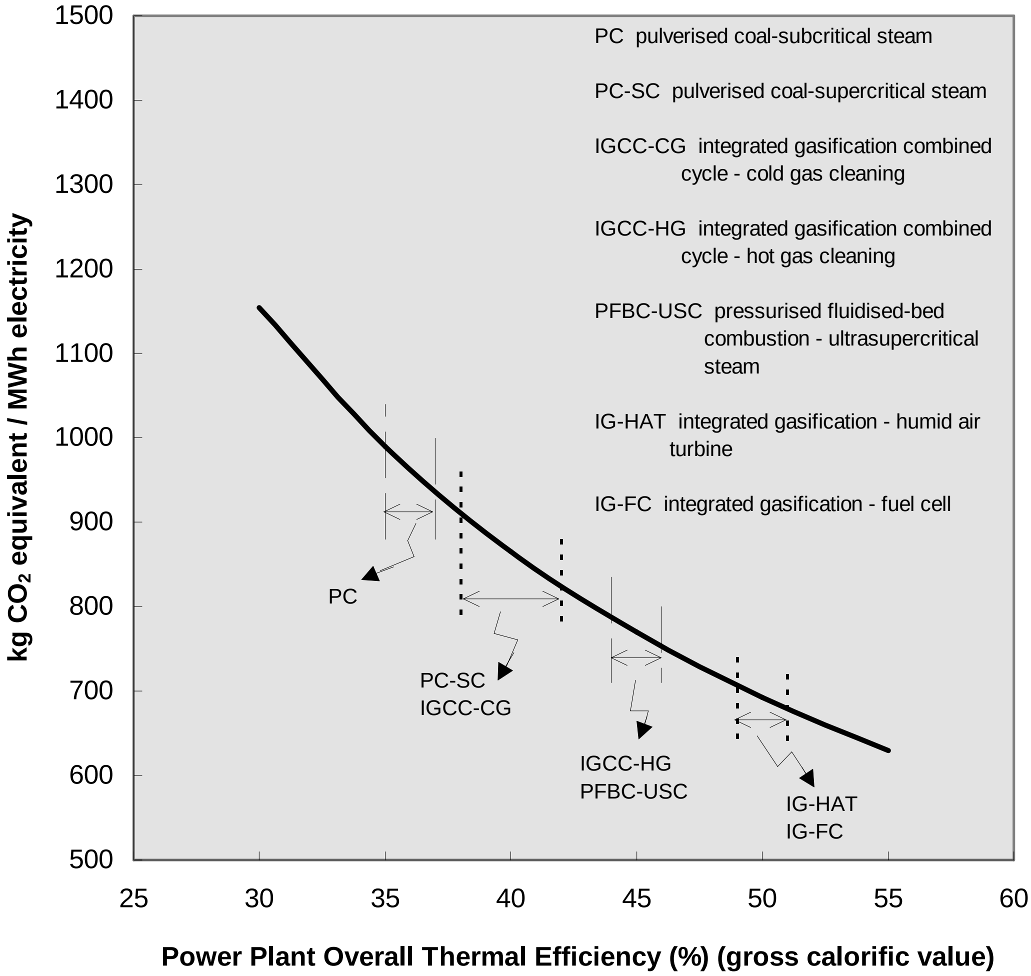

Figure 2 *Lifecycle greenhouse gas emissions for Case 1 - Coal as a function of power plant overall thermal efficiency*

3.3 CASE 2: Production and Export of Australian LNG to Japan for Electricity Generation

General Description

A flow diagram of the Case 2 fuel cycle for LNG is given in Figure 3.

This scenario follows the known gas fuel cycle for the NWSGP. Offshore natural gas from the North West Shelf Project of WA is recovered and processed in an onshore gas processing and liquefaction plant to produce LNG, condensate and a fuel gas for domestic consumption. The LNG is transported by dedicated ocean tankers from Karratha, WA to Japan. The scenario assumes that the LNG is used to generate electricity in a base load gas turbine-combined cycle power plant. The effect on the lifecycle greenhouse gas emissions of using alternative gas-based power generation technologies is also considered. CSIRO developed the lifecycle analysis.

Emissions Associated with the Production of LNG and its Export to Japan

The emissions associated with recovery of gas, liquefaction and shipping to Japan are based entirely on the confidential emission inventory data supplied to CSIRO by Woodside Offshore Petroleum Pty Ltd.

The emission inventory is based on the production 7,146,299 tonnes pa of LNG, together with 2,456,220 tonnes pa of condensate and 2,933,601 tonnes pa of gas for domestic consumption. Based on the information supplied to CSIRO by Woodside Offshore Petroleum Pty Ltd (S. Waller, private communication), the emissions directly attributable to the production and shipment of the LNG fraction only have been determined on the following basis:

- The CO_2 emissions from fuel used in the gas turbines applying to LNG are 2,414,636 tonnes pa, or 88.05% of the emissions from this source given in the original inventory.

- The CO_2 emissions from flaring applying to LNG are 103,119 tonnes pa, or 50% of the emissions from this source given in the original inventory.

- The diesel and fuel oil used for LNG shipment are 17,386 tonnes pa, or 56.2% of the total diesel fuel given in the original inventory.

- All of the gas boil-off of 192,950 tonnes pa in the original inventory is attributable to LNG production.

- All of the emissions from the acid gas removal step given in the original inventory are attributable to LNG production.

- None of the emissions from either the process combustion furnaces or the Mobile Offshore Drilling Unit are attributable to LNG production.

The emissions of other greenhouse gases from the power generation gas turbines, flaring and the diesel and fuel oil used in LNG shipment have been calculated by simply prorating the corresponding figures in the Woodside inventory using the percentage factors of 88.05%, 50% and 56.2% respectively.

The data give the total CO_2 equivalent of the emissions attributable to LNG production and transport as 5,827,066 tonnes pa to produce 7,146,299 tonnes pa of LNG which, after deducting the 192,950 tonnes pa used in ocean transport, is assumed to be used for power generation in Japan. On this basis, the total greenhouse gas emissions to the point of getting the LNG to the power plant in Japan are 838.0 kg of CO_2 equivalent per tonne of LNG.

The composition of the LNG is given in Table 4 (S. Waller, private communication)

Table 4 Composition of LNG shipped to Japan

Component	Mol%
CH_4	89.13
C_2H_6	7.32
C_3H_8	2.59
C_4H_{10}	0.87
C_5H_{12}	0.03
N_2	0.06
Total	**100.00**

On the basis of this composition, the gross and net calorific values of the LNG are 54.535 and 49.327 GJ/tonne respectively, and the quantity of CO_2 generated from the complete combustion of 1 tonne of LNG is 2.7874 tonnes.

The emission inventory has been used to prepare Table 5 which shows the greenhouse gas emissions associated with the offshore production platform, the LNG production plant and the shipping of the LNG product to Japan.

Electricity Generation from LNG in Japan

LNG can be used to generate electricity via single cycle gas turbine and Rankine steam cycle technologies or via combined gas turbine/steam cycle power plants.

Since LNG is a premium fuel which should be utilised with the maximum possible efficiency, it is obviously preferable to use it in combined cycle or co-generation systems (i.e. combined production of electricity and process heat or steam) where the overall thermal efficiencies are considerably greater than either of the single cycles alone. In this analysis the emphasis is on using gas turbine-combined cycle (GTCC) electricity generation, although the effect of using single cycle systems on the overall lifecycle greenhouse gas emissions will also be considered.

There have been very significant developments and improvements in GTCC technology over the last decade and these are continuing. The substantial gains in overall combined cycle efficiency and reduction in both NO_x and CO emissions have been the result of the major improvements in gas turbine technology. New materials of construction for the turbine blades have enabled higher turbine inlet temperatures to be used for increased thermal efficiency. New burner designs and modifications to the combustion cycle within the gas turbine have allowed the higher efficiencies to be obtained whilst reducing overall emission levels.

The modern commercially-available gas turbine technology is exemplified by machines such as ABB's GT24 (165 MW_e output) and GT26 (240 MW_e output) turbines which are claimed to have single cycle thermal efficiencies of 37.5 and 37.8% (net calorific value) respectively (Bach et al., 1995) whilst having NO_x emission levels of <25 ppm in the turbine exhaust gas (15 vol% O_2 dry basis). When these machines are used in GTCC plants the overall combined cycle outputs are 250 and 364 MW_e with overall thermal efficiencies of 57.7 and 58.2% (net calorific value) respectively. Other gas turbines, such as the Westinghouse W501G (230 MW_e output), offer similar performances in single and combined cycle operating modes (Anon, 1994).

The above power plant performance data are based on using natural gas, rather than LNG as fuel, and having the plants operating in a base-load mode at or near the design condition. The latent heat of vaporisation of LNG is equivalent to about 1% of its net calorific value. Depending on how this energy is supplied, there may be emissions associated with the LNG vaporisation step prior to power generation. Also there would be some efficiency penalty incurred if the GTCC plant operates under conditions substantially removed from its design point (e.g. at reduced outputs).

In the natural gas scenario used in the IEA Full Fuel Cycle Analysis an overall thermal efficiency of 52% (net calorific value) was used for the GTCC plant based on natural gas (rather than LNG) as fuel (IEA Greenhouse Gas R&D Programme, in-house data).

Under the assumptions used for this lifecycle analysis, the specific greenhouse gas emissions are a fixed value at the point where the LNG is received in Japan. Ignoring any small changes in the emissions of non-CO_2 greenhouse gases from the various electricity generating technologies, the overall emissions per unit of useful energy produced are then simply a function of the thermal efficiency with which this energy is produced.

Since the overall lifecycle greenhouse gas emissions per unit of electricity generated are critically dependent on the power plant thermal efficiency, and in view of the likely range of thermal efficiencies for the candidate technologies, the emissions have been plotted as a function of the end-use efficiency for the LNG in Figure 4. Also included here are the likely efficiency ranges for the single cycle and GTCC technologies which are available for electricity generation. Using the LNG in conventional Rankine steam cycle power plants will result in thermal efficiencies which are between these two ranges. The results in Figure 4 also include the CO_2 equivalent of the emissions from the gas turbine which have been assumed to be 25 ppm NO_x in the turbine exhaust (based on 15 vol % O_2 in the dry gas), as well as the emission factors for the other components (N_2O, CO, CH_4) as used in the IEA study (IEA Greenhouse Gas R&D Programme, in-house data).

The data in Figure 4 show that for an overall thermal efficiency of 55% net calorific value) for the GTCC plant, the total lifecycle greenhouse gas emissions are 492.6 kg CO_2 equivalent/MWh of electricity generated. If a single cycle (i.e. gas turbine only) power plant with a thermal efficiency of 38% is used, the overall lifecycle emissions increase to 713.0 kg CO_2 equivalent/MWh.

Table 5 Greenhouse Gas Emissions Associated with Production of LNG from the NWSGP and its Shipment to Japan

Type of Equipment	Emissions (kg per/tonne of LNG feed to power station)			
	CO_2	**CH_4**	**N_2O**	**NO_x**
1/ Production				
• gas turbines	347.262	0.053	0.028	0.846
2/ Flaring	14.830	0.193	0.001	0.008
3/ Cold Vents				
• gas vented	-	5.064	-	-
• acid gas removal	100.716	4.114	-	-
4/ Fugitive Emissions	-	0.014	-	-
5/ Transport				
• ship loading losses	-	0.006	-	-
• sea transport-diesel	8.001	0.001	0.001	0.148
• sea transport-gas	76.310	0.012	0.006	0.186
• air transport	0.460	0.000	0.000	0.002
6/ Power Generation in Japan				
• emissions in power plant flue gas	2787.4	-	-	2.16
Total Emissions	**3335.0**	**9.457**	**0.036**	**3.350**
GWP Factors	1	24.5	320	40
CO_2 Equivalent (kg/tonne LNG)	**3335.0**	**231.689**	**11.52**	**134.0**

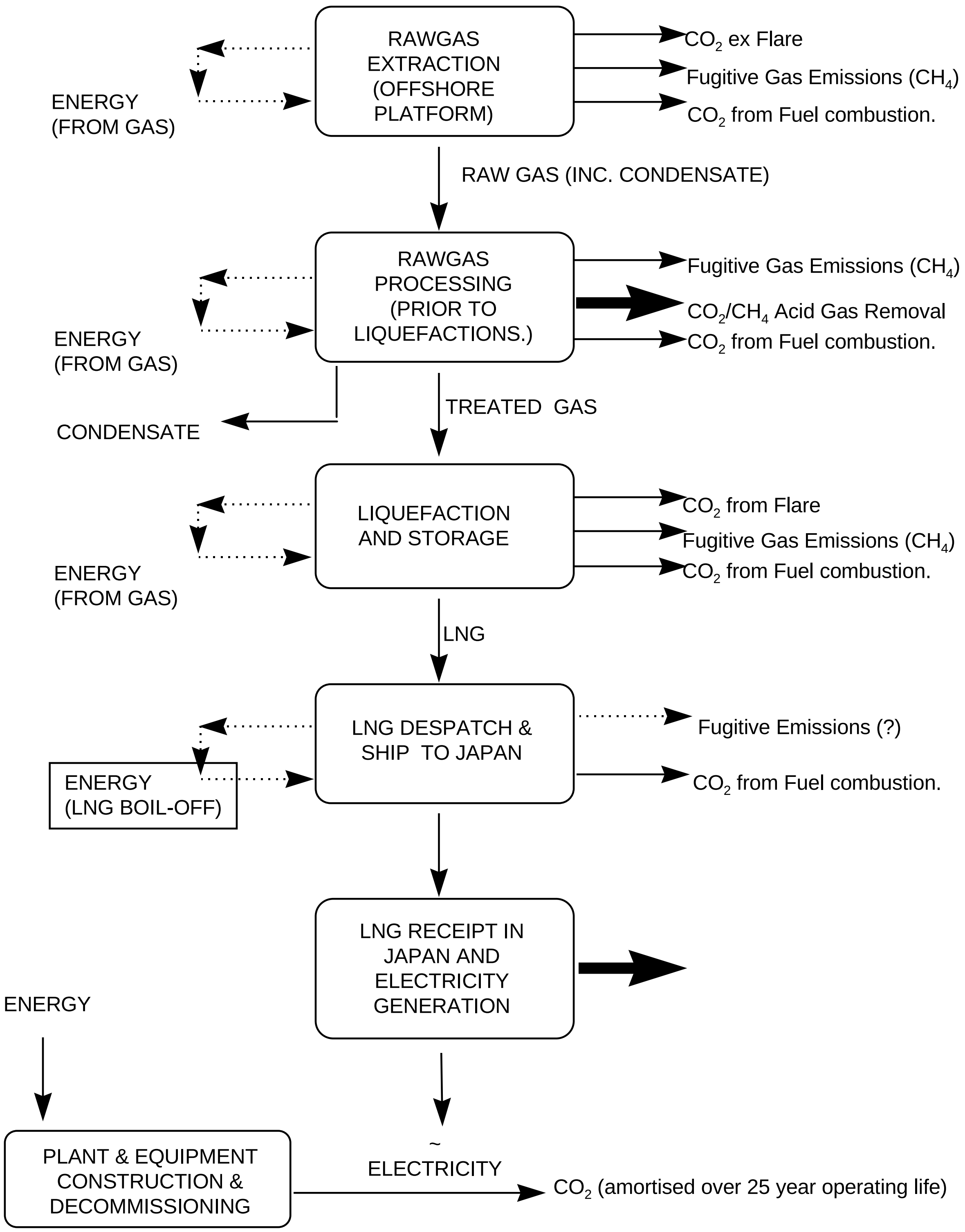

Figure 3 *Case 2: Woodside LNG production for acid gas vented case and export to Japan for electricity generation*

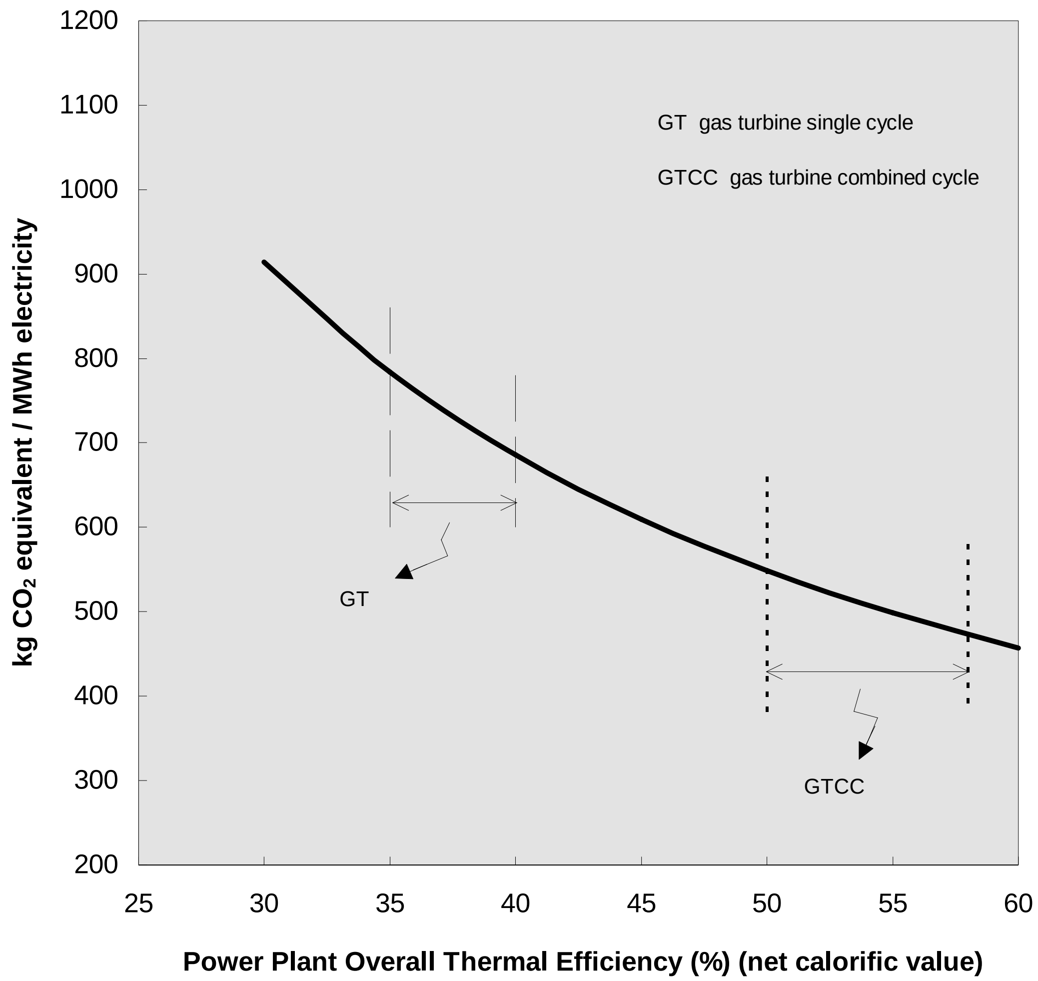

Figure 4 *Lifecycle greenhouse gas emissions for Case 2- LNG as a function of power plant overall thermal efficiency*

3.4 CASE 3: Electricity Generated in Japan from Imported Oil

General Description of Scenario Assumed

A flow diagram for the Case 3 fuel cycle for oil is given in Figure 5.

The scenario assumed for this estimate is the import of Middle East crude oil (e.g. from Saudi Arabia) into Japan where it is refined. A refined distillate or fuel oil fraction from the refinery is transferred to an adjacent power station where it is converted to electricity. The base case assumes that the power plant is a single Rankine steam cycle facility operating at 43% overall thermal efficiency. It is assumed that the oil has been refined to the extent that, with the incorporation of the appropriate SCR deNO_x unit, the emissions of N_2O and NO_x are reduced to the same levels as those used in the Case 1 estimate for coal-fired power generation.

<u>Assumptions and Factors Used to Estimate Greenhouse Gas Emissions</u>

Crude oil production

The energy consumed in producing crude oil is considered to be negligible in comparison to the energy content of the oil itself. This is particularly the case in the Middle East where the oilfields are very large and shallow, and the production facilities are already established and the energy required in drilling oil wells etc. has already been expended. Explicitly, we have effectively discounted greenhouse gas emissions associated with designed construction of the production facilities.

More important here are the greenhouse gas emissions associated with gas flaring and fugitive emissions of methane which occur during oil production and dispatch.

Atmospheric emissions of methane and VOCs during the production of oil come from exploration, associated gas vents and flares, process vents and flares, maintenance operations, energy requirements, compressors, pneumatic devices, system upsets and various fugitive emissions. It has recently been estimated (IEA Greenhouse Gas R&D Programme, in-house data) that these emissions amounted to a total of 3.126 Mt of CH_4 equivalent for the production of Saudi Arabian crude oil with a total energy content of 18,340 PJ. Assuming an energy content of 45.5 GJ/tonne for the oil, this is equivalent to methane emissions of 0.8 wt% of the oil produced (or 8 kg CH_4 per tonne of oil). This in turn equates to a CO_2 equivalent figure of 8 x 24.5 or 196 kg CO_2 equivalent per tonne of oil.

In addition to CH_4 emissions, CO_2 is emitted resulting from gas flaring operations. At this stage no data on the amount of CO_2 generated from this source have been located. In the absence of any published data on this topic, it has been arbitrarily assumed methane equivalent to 2 wt % of the oil produced is flared to produce CO_2. On this basis, the CO_2 generated from flaring is 55 kg/tonne crude oil. The total CO_2 equivalent of the greenhouse gas emissions from crude oil production (excluding the emissions of non-CO_2 greenhouse gases) are thus 251 kg/tonne of oil. The non-CO_2 greenhouse gases emissions from flaring have been estimated using the emission factors for gas flaring in the Woodside inventory namely, 35, 0.081 and 1.5 kg per tonne of methane flared for CH_4, N_2O and NO_x respectively.

Shipment of crude oil to Japan

An approximate estimate of the sea distance from Bahrain to Japan is 11,000 km. The emissions of greenhouse gases are assumed to be the same values per tonne-km as those used in Case 1 for bulk coal carriers (BTCE, 1995).

Refining of crude oil in Japan

The energy consumed in refining of crude oil is essentially derived from the crude oil itself, where large refineries (such as those in Japan) have their own fuel and electricity generating facilities.

The specific energy consumption depends not only on the size of the refinery and its complexity, but also on the properties of the crude oil and the overall product spectrum from the refinery. In general, the energy consumed in refining varies between 4 and 10% equivalent of the crude oil intake (Plummer, 1984). At this stage, an average figure of 7% of the crude oil is assumed here, being the figure for a reasonably complex refinery which includes facilities for crude distillation, hydrodesulfurisation, catalytic reforming and catalytic cracking. The crude oil is assumed to contain 86 wt % carbon (Plummer, 1984)

Since most of the fuel used in refining is consumed in combustion processes (e.g. electricity generation, refinery furnaces etc.) the greenhouse gas emissions from the refinery fuel are taken as those given for stationary combustion appliances such as a residual oil-fired furnace/boiler.

Flaring occurs in refineries as a result of numerous factors such as upsets to normal operation, emergency pressure release on process vessels and preparation of process equipment for maintenance. No reliable data on the amount of hydrocarbon flared during refining has been obtained. However, some allowance should be made for emissions associated with flaring and, in the absence of any published data, an arbitrary figure of 0.5 wt % of the crude oil throughput has been assumed to be lost to the flare which generates CO_2 and non-CO_2 greenhouse gases which are estimated using the emission factors for flaring in the Woodside inventory.

Fugitive emissions of hydrocarbons occur from refineries and product storage tanks. In this analysis these emissions are simply treated as being methane with a figure of 1800 kg of methane emitted per PJ of crude oil refined (Intergovernmental Panel on Climate Change (IPCC), 1994).

The overall yield of refined products is taken as 0.90 tonnes/tonne crude oil intake. As long as the energy required for refining is simply distributed evenly over the entire product spectrum, this figure can be used to convert the greenhouse gas emissions for crude oil production, transport and refining to figures on a per-tonne-of-oil fed to the power station basis.

Electricity generation in Japan

For the base case, the power plant is assumed to be a Rankine cycle facility, with a supercritical steam boiler, operating with an overall thermal efficiency of 43% (gross calorific value basis). The feed is a low sulphur fuel oil containing 86 wt% carbon and a gross calorific value of 44.5 MJ/kg.

As with the other cases, the lifecycle greenhouse gas emissions are strongly dependent on the power plant thermal efficiency and there is a range of technologies available for generating electricity from oil, depending on the properties of the oil. For example, GTCC technology can be used if the oil feedstock is a light distillate or naphtha fraction. In this case the overall thermal efficiency will be higher than that given above for the Rankine cycle power plant and will approach those for LNG-based GTCC plants. The effect of power plant efficiency on the lifecycle greenhouse gas emissions will be considered further.

Results of the Estimate

The detailed emissions inventory for Case 3 base case is given in Table 6. The total emissions are 690 kg CO_2 equivalent per tonne of oil feed to the power plant. Combustion of the oil in the power plant generates further greenhouse gas emissions of 3,180 kg CO_2 equivalent per tonne of oil, giving a total lifecycle emission rate of 3,870 kg CO_2 equivalent per tonne of oil feed.

Based on the 43% efficiency (gross calorific value) for the power station, one tonne of fuel oil would generate 5.32 MWh of electricity and the overall greenhouse gas emission rate for the fuel cycle is 728 kg CO_2 equivalent/MWh.

Light oils such as naphtha, gasoline and kerosene etc. can be used in GTCC power plants with overall thermal efficiencies approaching those based on natural gas. However, these are usually premium transport fuels or petrochemical feedstocks. The heavier components of the refinery product slate (e.g. fuel oils) must also be effectively utilised and this is normally done by using them in stationary combustion applications for heat and electricity generation. These heavier fuels are generally not suitable for gas turbine or GTCC applications and hence they are normally used in Rankine cycle steam plants.

The lifecycle greenhouse gas emissions for power generation from oil are thus dependent on which fraction of the refinery product slate is used as feed, since this determines the type of power generation technology can be used. Figure 6 shows the lifecycle greenhouse gas emissions as a function of power plant thermal efficiency with the range of emissions for oil-based GTCC power plant indicated. Clearly, if used in the more efficient combined cycle mode, the oil fuel cycle is much improved and in fact approaches, although does not reach, the emission for the Case 2 LNG cycle. For example, if the overall thermal efficiency of the oil-based GTCC plant is 51% (gross calorific value) or 55%(net calorific value), the lifecycle greenhouse gas emissions are 614 kg CO_2 equivalent per MWh, compared with 493 kg CO_2 equivalent per MWh for LNG with the same power plant overall thermal efficiency.

Table 6 Case 3 - Power Generation in Japan from Middle East Crude Oil

Stage in Fuel Cycle	Atmospheric Emissions (kg/tonne fuel oil feed to power plant)			
	CO_2	CH_4	N_2O	NO_x
1/ Crude Oil Production				
• methane emissions	-	8.89	-	-
• emissions from flaring	61.1	0.78	0.0018	0.034
2/ Crude Oil Transport to Japan				
• energy for shipping	53.8	0.002	0.0015	1.115
3/ Crude Oil Refining in Japan				
• energy for refining	245.5	0.01	0.002	0.545
• fugitive emissions and flaring	16.0	0.30	0.0005	0.010
4/ Power Generation in Japan				
• energy for shipping	3,153.3	0.001	0.020	0.500
Total Emissions	**3,529.7**	**9.983**	**0.026**	**2.204**
GWP Factors	1	24.5	320	40
Total CO_2 Equivalent	**3,529.7**	**244.6**	**8.3**	**88.2**

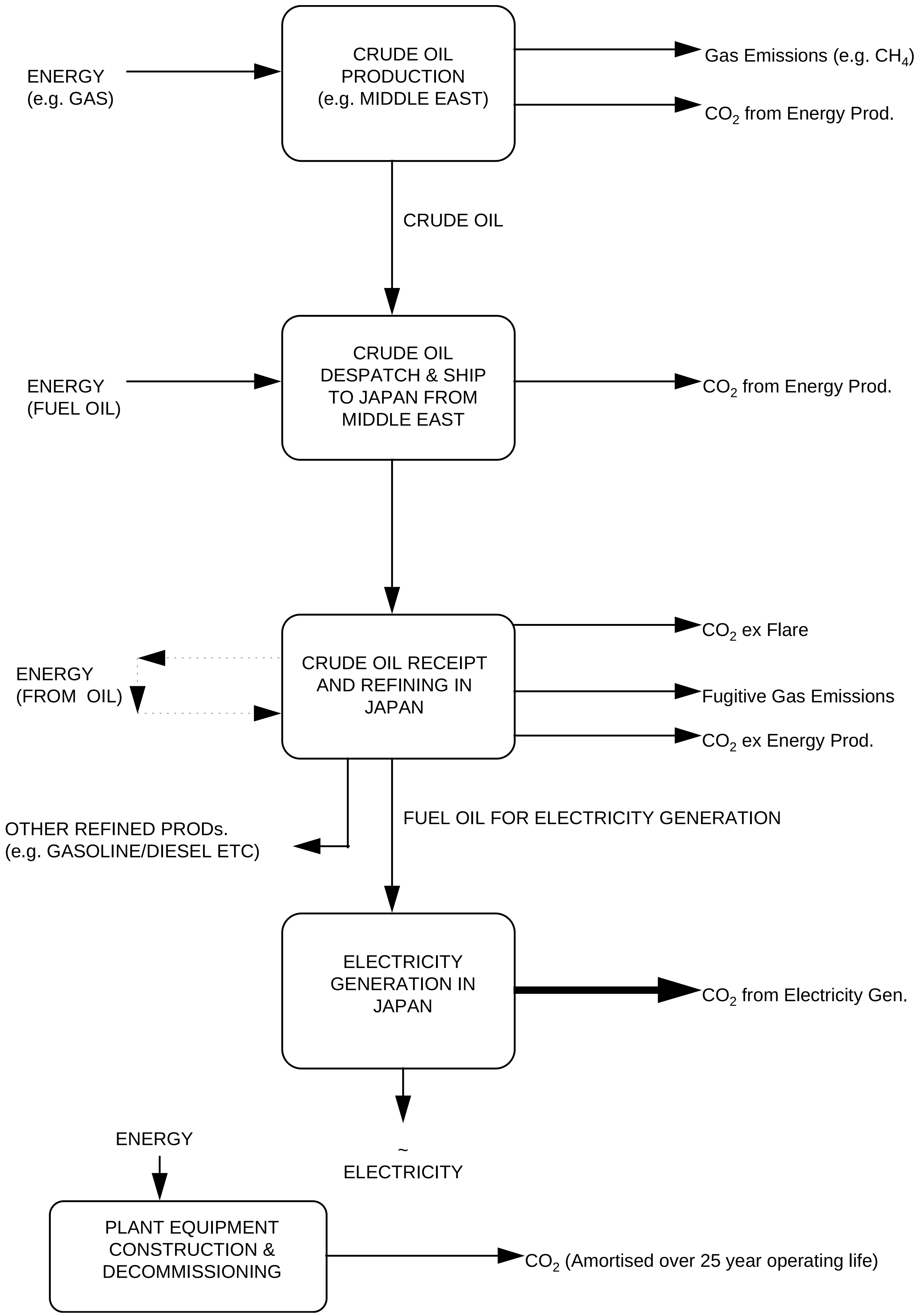

Figure 5 Case 3: Crude oil from Middle East - electricity generation in Japan

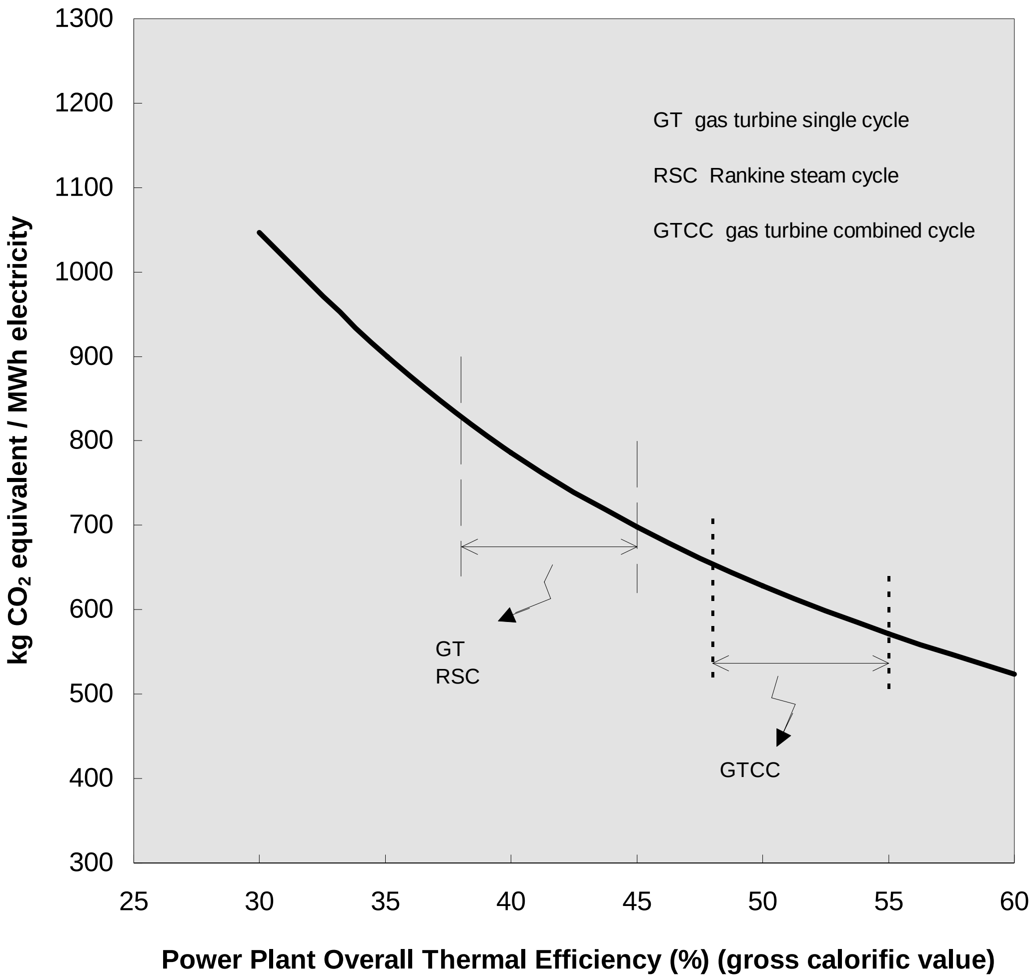

Figure 6 *Lifecycle greenhouse gas emissions for Case 3 - Oil as a function of power plant overall thermal efficiency*

3.5 Justification for Excluding Greenhouse Gas Emissions Associated with the Construction and Decommissioning of Plant and Equipment

The greenhouse gas emissions associated with the construction and decommissioning of plant and equipment have been addressed in the IEA Full Fuel Cycle Analyses (IEA Greenhouse Gas R&D Programme, in-house data) by estimating them and prorating them over the 25 year operating life of the fuel cycle as if they were emitted continuously during this period. When considered on this basis, they can then be compared directly with the emissions from the fuel cycle as given in Tables 3, 4 and 6.

The IEA study made an estimate of the greenhouse gas emissions associated with providing the raw materials (steel, cement, aggregate etc.) for the construction of the power station, the largest single part of the plant and equipment used in the fuel cycle. When these emissions were prorated over the operating life of the fuel cycle, the CO_2 figure for construction and decommissioning of the power station was only 0.054% of the annual generation of CO_2 from coal combustion in the power station. The other emissions were equally as trivial.

A further example can be given by considering the greenhouse gas emissions associated with providing the major materials of construction for Woodside's North West Shelf LNG production facility.

The LNG facility contains 132,000 m^3 of concrete, 70,000 tonnes of construction steel and 11,300 tonnes of steel piping. In addition, each of the 3 parallel processing trains contains a main cryogenic heat exchanger with 1,500 km of aluminium tubing, an air-cooled heat exchanger bank each with 352 km of finned aluminium tubing together with many other pieces of process equipment etc. (Woodside Offshore Petroleum Pty Ltd, 1992).

With respect to the greenhouse gas emissions associated with concrete, this material can be considered to be a 1/6 (wt ratio) of Portland cement and sand plus aggregate. The CO_2 generated from the manufacture of Portland cement are derived essentially from the coal fuel used for clinker production and the decomposition of the limestone feed. These emission are around 0.85 tonnes of CO_2 per tonne of cement or 23,000 tonnes to produce the cement used in construction of the LNG plant.

The energy for sand and aggregate production comes principally from industrial diesel fuel used in the quarrying and transport operations. This has been estimated to be around 0.12 GJ per tonne of sand plus aggregate. The CO_2 emitted from the combustion of diesel (87 wt % C, 45.5 GJ/tonne) required to produce the sand plus aggregate amounts to only around 1400 tonnes. The total CO_2 emission associated with concrete production are about 25,000 tonnes.

The energy for steel production comes principally from coal through the production and consumption of metallurgical coke and coke oven by-products. The energy consumption has been reported to be around 22 GJ per tonne of steel (IEA Greenhouse Gas R&D Programme, in-house data). On this basis, the coal consumed in the production of 83,300 tonnes of steel is about 68,000 tonnes and would emit 161,000 tonnes of CO_2.

The tonnage of aluminium in the cryogenic heat exchangers has been estimated on the basis of the tubes being 2.54 cm OD BWG No. 8 (wall thickness 4.2 mm) which weigh 0.762 kg/m. On this basis, the weight of aluminium required is about 4,300 tonnes.

The energy consumed in the aluminium metal production chain has been reported as being 304,200 MJ per tonne of metal based on a coal energy equivalent 10.9 MJ per kWh of the electricity consumed in the aluminium smelter (by far the largest single energy consumption) (Anderson and Haupin, 1978). This energy consumption translates to 26.6 tonnes CO_2 per tonne of metal, and to this must be added the 1.8 tonnes of CO_2 generated by the consumption of the carbon anode in the electrolytic cell used to produce aluminium (Anderson and Haupin, 1978). On this basis, the CO_2 emissions associated with the production of the aluminium used in the LNG plant approximately 122,000 tonnes.

The total CO_2 generated from the production of the steel, concrete and aluminium used in the LNG plant is 308,000 tonnes. To put this figure into proper context, the LNG plant produces 7,146,299 tonnes pa of LNG and emits more than 6 Mt pa of CO_2 equivalent in the production and shipment of the LNG to Japan. Over a 25 year operating life the total CO_2 equivalent of the greenhouse gas emissions from the production, shipment and combustion of the LNG is more than 640 Mt. The emissions associated with the supply of the basic materials of construction for the LNG plant are less than 0.05% of those generated from the production and consumption of the LNG.

Although there is other plant and equipment used in the overall fuel cycle (e.g. LNG sea carriers, power station etc.), the greenhouse gas emissions associated with their construction would also be equally as trivial. On this basis, it is justified to treat these emissions as being negligible in the overall fuel cycle and, as such, no further work was done in their estimation.

One aspect of the plant that is not included in this lifecycle analysis is the energy required to manufacture the plant out of the raw materials of steel, aluminium and concrete. Previous analyses have shown that this energy component is much smaller than the energy required to manufacture the raw materials hence it represents a diminishingly small component of this analysis and is neglected.

4. Comparative Advantages and Disadvantages of LNG, Coal & Oil

This analysis clearly demonstrates that, in each of the 3 cases, the specific life cycle greenhouse gas emissions per unit of electricity generated are dominated by the overall thermal efficiency of the power plant. This is shown by the fact that the greenhouse gas emissions from the power plant are 91%, 77% and 82% for the coal, LNG and oil base cases respectively. The LNG has the lowest figure since it is, amongst other things, the most energy-intensive of the three fuels to produce.

On the basis of the greenhouse gas emission inventory supplied by Woodside for its LNG production operations and using the assumptions outlined in this analysis, LNG clearly has lower life cycle greenhouse gas emissions than coal and, to a lesser extent, oil when used for electricity generation via existing commercial technology. The gap between LNG and coal would be narrowed substantially if the new clean coal power generation technologies approaching commercialisation live up to their promise in improving the overall thermal efficiency compared to that of the existing pulverised coal-based Rankine steam cycle technology. However, even under these circumstances, the emissions for LNG are still significantly lower than those for coal.

The comparison of the greenhouse gas emissions from LNG and oil are perhaps not so clear cut because of the uncertainties in the fugitive and flaring emissions associated with the oil fuel cycle and more importantly, as discussed earlier in this report, because the efficiency of generating electricity from oil depends on the properties of the oil fraction used as power plant feed. If a fuel oil suitable only for single Rankine steam cycle power generation is used, then LNG used in a GTCC plant has much lower life cycle greenhouse gas emissions per MWh. On the other hand, if a light distillate fuel oil is used in a GTCC plant the gap LNG and oil narrows but does not close completely.

A major advantage of LNG technology is that it enables remotely-located natural gas resources to be transported economically and made available for effective utilisation. Its major component, methane, has the lowest greenhouse gas emissions per unit of released energy of all the fossil fuels and, in the case of electricity generation, it is being used for this purpose now in the most thermally efficient combined cycle technologies.

5. Emission Factors and Uncertainty Analysis of Whole Lifecycle Emissions

5.1 Background Information

The logical basis of uncertainty analyses for greenhouse gas emission inventories has not been fully documented. Brief descriptions of this uncertainty issue are given in IPCC (1995a) and NAPAP (1990).

There can be two contributions to uncertainty in the analysis. One is a bias in the results due to an incorrect specification of the emission processes, such as overlooking an emission in the calculation. This bias is associated with missing knowledge, omitted sources, incorrect emission factors etc.. In keeping with the other analyses cited above we omit further consideration of such bias here. The other contribution to the uncertainty is precision in this case the possible variation of each of the components in the emission calculation.

The variability that makes up the precision of each of the terms in the emission calculation arises from several sources. We take, as an example, the NO_x emissions from gas turbines used for electricity generation. The emission factor will vary with design of plant, with load and probably with ambient environmental conditions. In theory, the precision would be determined by a full set of measurements of the emission factors over a representative set of plant, operating conditions etc. The variability in the results, as expressed as a standard deviation, provides the basis for precision. In cases where extensive measurements of terms have not been undertaken so that the standard deviations cannot be derived, then best professional judgement is used to estimate the likely magnitude of the standard deviation.

In compiling sets of emission factors, the compiler is forced to group activities that lead to greenhouse gas emissions into various categories and then compile emission factors for each of these categories. Perhaps one of the major sources of difference in emission factors from one compilation to another involves the definitions of the various categories. In the presence of extremely few measurements of emission factors and incomplete documentation of the specific activity they apply to, as well as comparably incomplete documentation of the actual activities that occur within nations, it is not surprising that differences of 50% or more in the choice of a specific emission factor can occasionally arise.

A further uncertainty arises because emissions of carbon monoxide and volatile organic compounds are not included in this study. The GWPs for these gases are very uncertain as is the GWP for NO_x. Of the three cases the VOC emissions are likely to be largest for the LNG case and the CO emissions smallest for the LNG case. Preliminary calculations indicate that the inclusion of these two gases will at most change the ratio of the CO_2 equivalent emissions per MWh between any two of the case studies by approximately 5%.

5.2 This Study

The greenhouse gas emissions presented in this lifecycle analysis are calculated on the basis of activity data (IPCC 1995a, b, c, NGGIC 1996a, b, c). The activities are the basic operations of the flow of resource from its origin to final fate.

The emission in CO_2 equivalent units are calculated from the formula

$$E_T = \sum_i \sum_j A_i Ec_i \, Ef_{ij} \, R_{ij} GWP_j \tag{1}$$

where:

A	=	rate of the activity
E	=	emission in CO_2 equivalent units
Ec	=	energy conversion efficiency for the activity
Ef	=	gas emission factor for the activity
R	=	removal of gas before release to atmosphere
GWP	=	global warming potential
i	=	subscript indicating particular activity
j	=	subscript indicating particular greenhouse gas
$_T$	=	subscript indicating total

For the purpose of reporting uncertainty, the recommended standard (IPCC 1995a) is the pair of symmetric 95% confidence limits, that is where for a comprehensive set of measurements of the parameter under consideration, 95% of the observations would fall within the confidence limits. For the normal or Gaussian distribution this corresponds approximately to the limits specified by two standard deviations about the mean value. These confidence limits are expressed in percentage units as a fraction of the value of the parameter being examined, and are represented as:

where:

U	=	100 $\lvert\Delta\rvert$/mean value; this is the percentage relative uncertainty at 95% confidence limits
Δ	=	the difference between the estimated parameter and the upper or lower symmetric 95% confidence limit.

To determine the total uncertainty in the lifecycle analysis, there is need for a method to combine the uncertainties in individual terms.

The method used here (IPCC 1995a, b, c, NGGIC 1996a, b, c) is based on the statistical technique of the sum of variances, basically

$$E_T U_T = \sqrt{\sum_i E_i^2 U_i^2}$$

Key assumptions underpinning the use of this formula are:

- the different error components are uncorrelated
- the distribution of data within a set is normal

In the cases where best professional judgement is used to provide uncertainty analyses, the scale is one of confidence presented as the percentage relative uncertainty at 95% confidence limits:

L	=	>20% uncertainty
M	=	5–20% uncertainty
H	=	0–5% uncertainty.

These ranges are recommended by the NGGIC (1996a, b, c). The NGGIC (1996a, b, c) provide estimates of the uncertainty of emissions and emission factors from the various processes described here, and their estimates are used in these analyses. The two exceptions are: CO_2 emissions from oil extraction where we adopt a low confidence, and CO_2 emissions from ocean shipping where we adopt a high confidence, both based on the information in the case studies.

The particular values we use to translate H, M and L into quantitative estimates of uncertainty are:

L	=	30%
M	=	12%
H	=	2%.

The uncertainty analyses that arise in the application of this methodology to the three case studies are presented in the following Tables 8, 9 and 10.

Three features are evident from Tables 8, 9 and 10. Firstly the differences are highly significant in CO_2 equivalent emissions per MWh between the coal, LNG and oil cases. More than 90% of the emissions arise directly as CO_2 for these three cases. The major source of variance in the total emissions arises from the power plant characteristics in coal and LNG cases and due of CH_4 loss during production in the case of oil from the Middle East.

Table 7 Greenhouse Gas Emissions for Case 1 - Power Generation in Japan from Australian Coal (Hunter Valley - Open Cut). Units kg CO_2 equivalent/MWh

Stage in Fuel Cycle		Atmospheric Emissions (E) and the 95% confidence limits (Δ)				
		CO_2	CH_4	N_2O	NO_x	Total
Coal Mining	**E**	12.3	24.2	0.1	9.8	46.4
	Δ	0.3	7.3	0.0	2.9	7.8
Coal Preparation	**E**	0.8	0.0	0.0	0.2	0.9
	Δ	0.0	0.0	0.0	0.1	0.1
Domestic & International Transport	**E**	12.6	0.0	0.1	10.6	23.3
	Δ	0.2	0.0	0.0	1.3	1.3
Electricity Generation and Associated Activities	**E**	784.7	0.0	2.5	6.7	793.9
	Δ	15.6	0.0	0.7	0.9	15.6
Total Emissions	**E**	810.4	24.2	2.7	27.2	864.6
Uncertainty	**Δ**	15.6	7.3	0.7	3.3	17.5

Table 8 Greenhouse Gas Emissions for Case 2 - Power Generation in Japan from LNG from the North West Shelf. Units kg CO_2 equivalent/MWh

Stage in Fuel Cycle		Atmospheric Emissions (E) and the 95% confidence limits (Δ)				
		CO_2	CH_4	N_2O	NO_x	Total
Gas Production	**E** **Δ**	2.8 0.2	7.7 0.9	0.1 0.0	0.2 0.1	10.7 1.0
Gas Purification and Liquefaction	**E** **Δ**	58.6 2.0	23.0 2.1	1.1 0.3	4.4 1.3	87.1 3.2
International Transport	**E** **Δ**	11.2 0.2	0.0 0.0	0.3 0.1	1.8 0.2	13.4 0.3
Electricity Generation	**E** **Δ**	369.9 7.4	0.0 0.0	0.0 0.0	11.5 3.4	381.3 8.2
Total Emissions	**E**	442.5	30.7	1.5	17.8	492.5
Uncertainty	**Δ**	7.7	2.3	0.4	3.7	8.8

Table 9 Greenhouse Gas Emissions for Case 3 - Power Generation in Japan from Middle Eastern Oil. Units kg CO_2 equivalent/MWh

Stage in Fuel Cycle		Atmospheric Emissions (E) and the 95% confidence limits (Δ)				
		CO_2	CH_4	N_2O	NO_x	Total
Crude Oil Production	**E**	11.9	44.6	0.1	0.3	56.4
	Δ	3.4	13.4	0.0	0.1	13.8
Crude Oil Refining in Japan	**E**	49.1	1.4	0.2	4.2	54.9
	Δ	1.3	0.4	0.0	1.2	1.8
International Transport	**E**	10.1	0.0	0.1	8.4	18.6
	Δ	0.2	0.0	0.0	1.1	1.1
Electricity Generation	**E**	593.2	0.0	1.2	3.8	598.2
	Δ	11.9	0.0	0.4	1.1	11.9
Total Emissions	**E**	663.9	46.0	1.6	16.6	728.1
Uncertainty	**Δ**	12.4	13.4	0.4	2.0	18.4

6. Conclusions

The lifecycle analysis has been carried out for the fuels electricity generation in Japan using Coal from Australia, LNG from Australia and Oil from the Middle East.

The study shows that for the conditions evaluated for electricity generation in Japan, LNG produces fewer greenhouse gas emissions than other fuels. The uncertainty analysis shows that, when using 95% confidence limits, the differences between the emission per unit of electricity for the three fuels are highly significant.

Due to the nature of these comparisons, the uncertainties in GWPs (omitted in these analyses but quoted at ±35%) are unlikely to influence the results. Similarly the omission of CO and VOCs are at most likely to change the ratio of emissions per MWh between the different fuels by 5%.

These analyses are based on the efficiencies of current electricity generating plant in Japan. The application of emerging technologies is expected to change the results of this study.

Key other features that are apparent from the uncertainty analyses are the CH_4 emission from coal and oil production and the NO_x emissions from LNG combustion. The CH_4 emissions from the relevant coal mining have been measured, but the CH_4 emissions associated with the oil production are only estimates based on professional judgements. The NO_x emissions used here are based on plant specifications.

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Appendix A: Abbreviations, Symbols and Units

A	rate of the activity
ADO	Automotive diesel oil
C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	Butane
C_5H_{12}	Pentane
CH_4	Methane
CO_2	Carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
Δ	95% confidence limit
E	emission in CO_2 equivalents
Ec	energy conversion rate for activity
Ef	gas emission factor for activity
FGD	Flue gas desulphurisation
GHG	Greenhouse gas
GTCC	Gas turbine-combined cycle
GWP	Global warming potential
H	>20% uncertainty
i	subscript indicating particular activity
IDO	Industrial diesel oil
IEA	International Energy Agency
IGCC	Integrated gasification - combined cycle
IG-FC	Integrated gasification - fuel cell
IG-HAT	Integrated gasification - humid air turbines
IPCC	Intergovernmental Panel on Climate Change
j	subscript indicating particular greenhouse gas
kg	kilograms
km	kilometre
L	0–5% uncertainty
LNG	Liquefied natural gas
M	5–20% uncertainty
MJ	Megajoule
Mt	million tonnes
mol	Mole
MWh	Megawatt-hour
N_2	Nitrogen
N_2O	Nitrous oxide
Nm^3	a cubic metre of gas at standard temperature and pressure
NO_x	Nitrogen oxide
NSW	New South Wales
NWS	North West Shelf
OD BWG	Outside diameter
PJ	Petajoule
pf	pulverised-fuel
PFBC	Pressurised fluidised-bed combustion
R	removal of gas before release to atmosphere
SCR	Selective catalytic reduction
T	subscript for total emissions
TJ	Terajoule
U	percentage relative uncertainty in parameter at 95% confidence limits
vol	volume
WA	Western Australia
wt	weight