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Economic Cooperation

OPTIONS TO REDUCE CO_2 EMISSIONS FROM ELECTRICITY GENERATION IN THE APEC REGION (Phase II)

Energy Working Group Project EWG 02/2001

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Expert Group on Clean Fossil Energy

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EXECUTIVE SUMMARY

This project provides broad insights into opportunities to improve electricity generation in APEC economies by reducing CO_2 emissions. Examples are selected from within the APEC region and externally to provide quantified data that can be used as a guide for other APEC economies as they develop their energy planning.

It is Phase II of a project commissioned by the APEC Experts Group on Clean Fossil Energy. The first phase identified 19 possible scenarios for reducing CO_2 emission within the APEC region and estimated the maximum potential saving.

This phase seeks to take into account local conditions to give attainable targets. A number of case studies are presented with impediments, opportunities and financial information. The selection is broad enough to allow energy planners to take advantage of the projects already executed and incorporate them into their alternatives.

In most cases the improvements were economically viable in their own right. Repowering initiatives were most successful, giving large increases in generating capacity for the same fuel consumption and corresponding large reductions in greenhouse gas release. This was achieved with little change in existing infrastructure.

The next most effective process was refurbishment of older units. This gave increased capacity at a lower cost than new plant together with reduced greenhouse gas release.

Most cases studied showed a CO_2 abatement benefit rather than a cost. This, together with access to equity to proceed with the improvements were major enabling factors.

In all cases governments played a key role in facilitating the process to achieve project aims. This included introduction of competitive electricity markets to allow foreign investment, cross economy collaboration, implementation of national greenhouse abatement schemes, policies requiring high efficiency generation plant for new installations, development of new generation technologies and providing funding for appropriate demonstration projects.

In addition, the energy planning for two APEC economies, Malaysia and Viet Nam was reviewed. These provide effective but quite different approaches to meeting generation needs using mainly indigenous resources economically and reducing greenhouse gas release. Suggestions, arising from the case studies, have been made to enhance these plans and at the same time reduce CO_2 emission.

The majority of case studies improved efficiency, increased plant output and reduced greenhouse gas release at economic cost. It is recommended that the key stakeholders be brought together in a suitable forum to encourage and facilitate adoption of measures such as these case studies demonstrate to help meet expansion needs and at the same time improve greenhouse abatement. Further, even more specific work is recommended to investigate opportunities for the implementation of measures to reduce CO_2 emissions within one APEC economy. Taking a longer term view, facilitation of international collaboration in the use and development of Zero Emissions Technologies (ZETs) in the APEC region is also recommended.

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1. INTRODUCTION

1.1 Background

A major concern for the world today is the risk of global warming arising from the continuing increase in carbon dioxide concentration in the atmosphere. Much of the increase comes from emissions of CO_2 from fossil fuel combustion for power generation.

The APEC economies encompass approximately 40% of the world's population and generate over 60% of global economic activity. Collectively they account for a large proportion of global energy use and CO_2 emissions. Growth in energy use in the developing economies in the APEC region is substantially higher than the average rate projected world-wide because of rapid economic development and population growth.

One way to manage the growth in carbon emissions is to increase the efficiency of electricity generation from fossil fuels, by upgrading existing power plants, and use of advanced technologies for new power plants. The Expert Group on Clean Fossil Energy (EGCFE) promotes the clean use of fossil fuels and advanced technologies that increase conversion efficiency and reduce environmental impacts.

To begin addressing the global environmental issue of growth in CO_2 emissions in the context of fossil power generation in the APEC region, the Expert Group commenced a project on "A Study of CO_2 Reduction Options in the APEC Region". Phase I of this study was completed in December 2001.

In Phase I key data on the power generation sector of each APEC economy was compiled and a review of CO_2 reduction options for fossil fuel power generation was undertaken. A number of potential scenarios that could be pursued by APEC economies for implementing CO_2 reduction options were identified. These covered a range of options and technology approaches. For each scenario, estimates of potential CO_2 emission reductions were developed across aggregate capacity for all APEC economies.

The estimates of CO_2 emission reductions across all APEC economies, presented in the Phase I study, do not take account of circumstances in individual economies, such as their level of development and rate of economic growth and the barriers to adoption of clean coal technologies in each economy. Also, the scenarios evaluated are not necessarily applicable to the same extent in each economy. More representative scenarios for individual economies would be mixes of CO_2 emission reduction options depending on a range of factors including the mix of generation already installed and the practicality of the various options on a site specific basis.

Building on the Phase I findings and recommendations the EGCFE initiated Phase II with the aim of assisting APEC member economies to gain a more practical understanding of the different CO_2 reduction options available for both existing and new fossil fuel-fired power plants. Phase II also aims to identify specific obstacles impeding adoption of cleaner, more efficient fossil fuel-based power plant in APEC economies.

HRL Technology was engaged by the EGCFE to conduct the Phase II study. To achieve the above objective, HRLT first reviewed the Phase I report, then prepared a number of detailed case studies of specific CO_2 reduction options already implemented or considered for implementation in the fossil electricity generation sectors in several APEC economies. Then, barriers and enabling factors for introduction of CO_2 reduction options were identified and analysed. Finally action plans were prepared for two of the developing APEC economies to provide possible scenarios in which future CO_2 emissions might be further reduced by adoption of some of the more promising CO_2 reduction options.

1.2 Scope of Work

1. Present a number of case studies of specific CO_2 reduction options already implemented, or considered for implementation, in the fossil electricity generation sectors of several APEC economies, including information on the approach taken to execute the option, the relative roles of the government and private sector in implementing the option, the technologies involved, the emission reductions obtained, and the associated costs and means to finance the project (where available).

2. Describe existing obstacles and barriers to the adoption of cleaner, more efficient fossil-fuel based generating technologies. Describe general governmental policies and initiatives required to support and promote more efficient technologies. Successful policies and initiatives, which could be adopted in other APEC economies, will be highlighted.

3. Review and comment on action plans for two developing APEC economies, with high CO_2 reduction potential, to hasten the adoption of fossil-fuel based power generating technologies that will yield lower CO_2 emissions over the short-to-medium term. The case studies and action plans must serve to illustrate the potential to reduce CO_2 emissions from fossil fuel power generation in all APEC economies.

1.3 Glossary

APEC	Asia-Pacific Economic Cooperation
CO_2	Carbon Dioxide
EGCFE	Expert Group on Clean Fossil Energy
HRLT	HRL (Herman Research Laboratory) Technology

2. REVIEW OF PHASE I REPORT

2.1 Summary

The Phase I Study Report was reviewed with particular reference to the range of CO_2 emission reduction options that had been identified, to see if any viable options had been overlooked, and if so, to add them to the list of options to be considered when identifying suitable candidates for case studies.

The report essentially takes a standard database of power stations in the APEC region and identifies the types and capacities of power station plant in the APEC economies. It then identifies four basic categories (see below) and within these a total of nineteen CO_2 reduction scenarios. The CO_2 reduction that could be achieved in each scenario if a reasonable proportion of the plants in each class were converted, irrespective of APEC economy or equipment manufacturer is estimated. There are broad variations in the number and capacity of plants in each class and in the possible reduction for that class.

The four basic categories of options identified are as follows :

- Combustion, steam cycle and O&M upgrades;
- Co-firing and switching to lower carbon fuel;
- Repowering with more efficient technology or biomass;
- Combined heat and power generation.

Quite significant savings are identified but these are highly diffused over different plant manufacturers and different economies. New plant is essentially not discussed. This approach produced what might be called a maximum possible CO_2 reduction, unattainable in practice. It did however identify those scenarios that had the best potential.

Each basic category is further broken down into more specific emission reduction scenarios, each given a notation from E1 to E19, as summarised in Table 1 (see page 14). In the first basic category, improvement in pulverised coal-fired units (E4) had the greatest potential, followed by improving oil- and gas-fired units (E1). In the second group co-firing gas in pulverised coal-fired units (E7) is the most attractive. In the third group all repowering scenarios are potentially attractive, depending on local conditions. This includes conversion of plants to combined heat and power where a suitable heat sink existed.

The implementation of CO_2 reduction would also reduce health-affecting emissions such as SO_x, NO_x and particulates, and these benefits are also discussed. This may be a far more potent driver for action in many less developed APEC economies, which place local health as far more important politically than CO_2 reduction. In fact health could well be the major driver with CO_2 reduction as a by-product in some economies.

The report is beneficial in that it identifies where large reductions are possible. The two most promising scenarios are E4 concerning improving pulverised coal units and E16 concerning repowering with Atmospheric Fluidised Bed Combustor (AFBC) and 100% biomass. It is plausible that the former scenario could be implemented but the latter covers 26,000 MW of biomass driven plant and it is doubtful that such a quantity of biomass is freely available for this option.

The report covers the basic technical possibility for any technology. It identifies significant savings but these are highly diffused in many economies and different plants, and it does not identify whether the resources of gas or oil or biomass are locally available at reasonable cost.

2.2 Specific Comments

Introduction

The report provided basic background information. It states it intends to identify the options available to reduce CO_2 and seek the more promising ones. Analysis of cost effectiveness or economic feasibility was seen to be outside the scope of the report. Data was based upon 1998 as reference year.

Methodology

Information was collected from Powergen 2001 conference in Kuala Lumpur by attendance and visits were made to Malaysia and China.

The methodology used in the questionnaire component did not result in comprehensive answers and alternative methods need to be developed.

Electricity Generation

There was a poor response to the questionnaire, so a variety of literature and database sources were used. These were analysed to show the distribution of the various types of generation over the APEC economies.

No mention was made of the change from monopoly to competitive conditions in the energy industry and the effect this might have on specific improvements, or on any improvements.

The existing power generation section divides up the database into coal- and gas- / oil- fired technologies, providing a basic description. There is some confusion as it states "coal gasification is well proven technology" but later in the document gasification is stated to be at a very early stage of commercialisation. While new technology is discussed the scenarios really only covered existing plant.

As well as existing power generation, an additional 800 GW is identified as being under construction or planned for the next 20 years within APEC. The data suggests that there will be a move towards gas and hydroelectric plants at the expense of coal- and oil-fired plants in the future. The major additions are expected to be in China and the United States, but other notable capacity increases include Thailand, Viet Nam and Malaysia.

CO_2 emission data are taken from IEA documents for 1998 generally. The major emitters of CO_2 from power generation are United States, Peoples Republic of China, Russia and Japan, more or less reflecting the size of those economies.

Review CO_2 Reduction Options

The report correctly identifies the importance of energy efficiency and fuel selection as the major drivers for reducing GHG emissions.

The review of emerging technologies includes comments on Integrated Gasification Combined-Cycle (IGCC) and Pressurised Fluidised Bed Combustion (PFBC) that are some years out of date especially with respect to availability. Several emerging technologies were not covered, including poly-generation in any form, or underground gasification.

The review of improvements to existing plant is comprehensive. The data was selected mainly from AGO and IEA publications and covers boilers, steam cycle, and operations and maintenance.

Repowering is defined as substantial upgrading but seems to include rebuilding with new technology. A range of possibilities are discussed, from full replacement on an existing site down to options where the existing plant remains, but with additional capacity having lower CO_2 intensity.

Switching to lower carbon fuels covers the expected options, but much is made of utilising biomass. However in many economies there is very little biomass available. One of the scenarios calls for 26,000 MW of biomass plant, which seems unrealistic.

CO_2 capture and sequestration is discussed separately, although it is rightly judged to be still an emerging technology. The advantages of gasification technologies for CO_2 capture are not identified. Sequestration is a more difficult matter and depends locally available storage capacity.

Non technical options such as regulatory and economic approaches were seen to be outside the scope of the project but are likely to be critical issues in the move to lower CO_2 emissions in any APEC economy.

Analysis of CO_2 Reduction Options

The various options are integrated into hypothetical scenarios, grouped into four basic categories. Each scenario is analysed by assuming that it would be applied across all economies, with reasonable assumptions about the take-up of the prospective option by applicable plants. The CO_2 reductions are obtained by summing all similar plants over all APEC economies, using installed capacities, plant and fuel types from the UDI database for 1998. The intention here is not to be a forecast, but just an estimate of the potential for each type of action to reduce emissions, given that the likelihood of all of one type being improved in many economies is slight.

Scenarios are based upon modifying existing plant without any consideration of stand-alone new plants. This might have been because there was not enough detailed data available on forward plans for the various economies. Hence new technology options were confined to repowering scenarios.

The efficiency gains and CO_2 reductions expected for each scenario appear reasonable, given the broad and non-specific nature of the estimates. This section is good in identifying those scenarios that are not really worth following.

Potential Health Issues

This section reviews the pollutant emissions from the various power generation technologies and discusses air quality issues in the APEC region. It shows that air quality in respect of major pollutants derived from fossil fuel use is poor in many developing APEC economies (not all of this can be attributed to power generation). Many of the CO_2 reduction options were identified as likely to lead to reduction in pollutant emissions, a significant advantage that might lead to greater take-up of some of them. The relative importance of air pollution compared with greenhouse reduction in APEC economies might act against CO_2 reduction in the first instance, but could be a driver for greenhouse reduction for some technologies.

Obstacles and Data Gaps

The report identifies obstacles to implementation of all scenarios, and points to the need for detailed, economy-specific evaluations.

2.3 Missing Technologies

Overall, the main CO_2 reduction options are covered well. The report seems to concentrate on modifying existing plant, with little attention given to new plant. Repowering seems to be used in a mixed sense, sometimes meaning improving old plant and sometimes meaning new installations to replace old ones.

Technologies considered important but which are missing from the report include the following:

- Poly-generation in any form;
- Underground gasification;
- Combustion of washery wastes, to reduce coal methane emissions;
- Real IGCC / PFBC applications, as new installations, rather than repowering.

2.4 Glossary

AFBC	Atmospheric Fluidised Bed Combustion
AGO	Australian Greenhouse Office
APEC	Asia-Pacific Economic Cooperation
CO_2	Carbon Dioxide
GW	Giga Watt
IEA	International Energy Agency
IGCC	Integrated Gasification Combined-Cycle
MW	Mega Watt
NO_x	Oxides of Nitrogen
O&M	Operation and Maintenance
PFBC	Pressurised Fluidised Bed Combustion
SO_x	Oxides of Sulphur
UDI	Utility Data Institute

3. SELECTION OF CASE STUDIES FOR CO_2 REDUCTION OPTIONS

3.1 Introduction

A primary goal for Phase II of this study is to assist APEC member economies in gaining a more practical understanding of the different CO_2 reduction options for both existing and new fossil fuel-fired plants. To achieve this objective, eleven case studies from eight member economies are presented in this report that detail specific CO_2 reduction options already implemented or considered for implementation.

The case studies cover a broad range of CO_2 reduction options including power station upgrades and refurbishment, co-firing, fuel switching, new generating plant, repowering of older units and combined heat and power. The full set of fossil fuels (coal, natural gas and oil) as well as biomass are included.

This Chapter outlines the selection criteria for the case studies, based around the potential scenarios to reduce CO_2 emissions from their fossil power generation sector that were developed during Phase I of this study. The case studies themselves are presented in Chapter 4.

3.2 Potential CO_2 Reduction Scenarios as Defined in Phase I

Phase I defined 19 emission reduction scenarios that can be applied to existing fossil fuel power stations. These have been reproduced in Table 1. Figure 1 (a copy of Figure 5-1 of the Phase I report) shows the CO_2 reduction potential of each of the scenarios, given assumed levels of implementation.

The top eight scenarios in terms of potential emission reduction across the region include scenarios from each of the four categories, although the likelihood of being able to successfully implement the second highest reduction scenario (E16 - repower with AFBC and 100% biomass) has been questioned as the levels of biomass required that may exceed the amounts available in the region.

Figure 1: CO_2 Emission Reduction in the APEC Region Based on an Assumed Level of Implementation of the Scenarios to Existing Power Plants in 1998

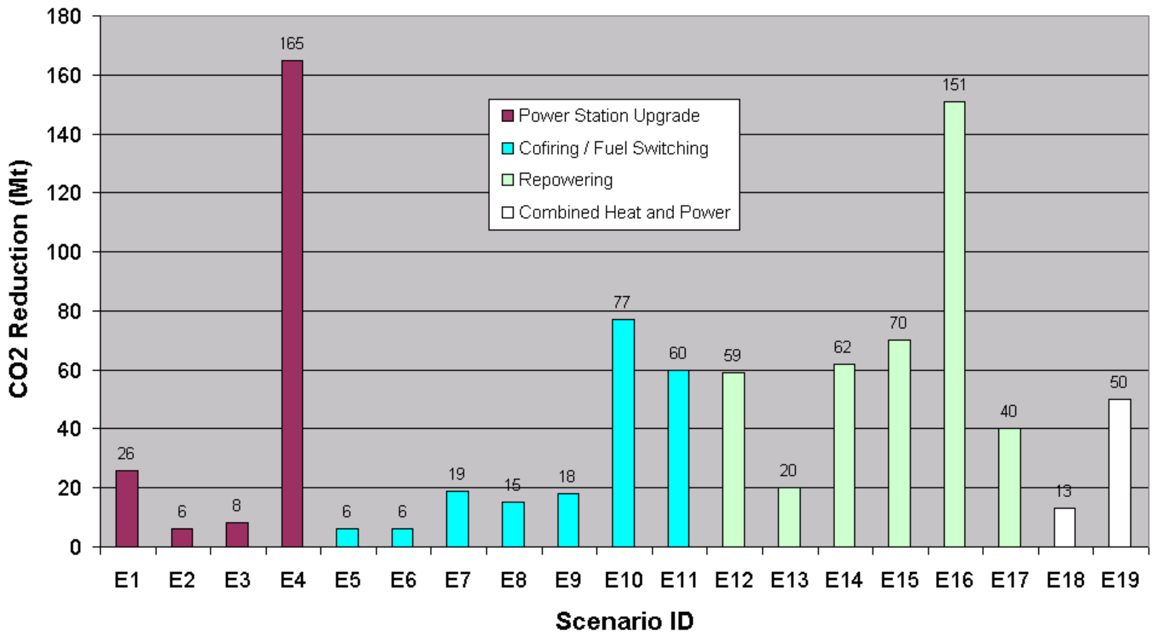

Table 1: Summary of Emission Reduction Scenarios Investigated

Basic Category	ID	Technology	Applicable Fuel	Applicable Technology
Power Station Upgrade	**E1**	Combustion, Steam Cycle and O&M Improvements	Oil, Gas	Steam Turbine, Subcritical
	E2	Combustion, Steam Cycle and O&M Improvements	Oil, Gas	GTCC and CHP
	E3	Combustion, Steam Cycle and O&M Improvements	Oil, Gas	Open Cycle GT
	E4	Combustion, Steam Cycle and O&M Improvements	Coal	Pulverised Coal Sub and Supercritical
	E5	Combustion, Steam Cycle and O&M Improvements	Coal	Stoker and Cyclone Coal Boilers
Co-fire / Fuel Switching	**E6**	Co-fire 25% Gas	Oil	Steam Turbine Subcritical
	E7	Co-fire 25% Gas	Coal	Pulverised Coal Subcritical
	E8	Co-fire 25% Oil	Coal	Pulverised Coal Subcritical
	E9	Switch to 100% Gas	Oil	Steam Turbine Subcritical
	E10	Switch to 100% Gas	Coal	Pulverised Coal Subcritical
	E11	Switch to 100% Oil	Coal	Pulverised Coal Subcritical
Repowering	**E12**	Repower with GTCC	Oil, Gas	Steam Turbine Subcritical
	E13	Repower with GTCC	Oil, Gas	Open Cycle GT
	E14	Repower with PC Super	Coal	Pulverised Coal Subcritical
	E15	Repower with AFBC and 20% Biomass	Coal	Pulverised Coal Subcritical, Stoker / Cyclone Coal Boilers
	E16	Repower with AFBC and 100% Biomass	Coal	Pulverised Coal Subcritical, Stoker / Cyclone Coal Boilers
	E17	Repower with IGCC or PFBCC	Coal	Pulverised Coal Subcritical, Stoker / Cyclone Coal Boilers
CHP	**E18**	Repower with CHP	Oil, Gas	Steam Turbine Subcritical
	E19	Repower with CHP	Coal	Pulverised Coal Subcritical

3.3 Criteria Used for Case Study Selection

In reducing CO_2 emissions from the fossil fuel electricity generation sector for APEC economies it is clear that a range of options will be required. The following criteria were used in selecting the case studies:

- Coverage of all of the Basic Categories and many of the Scenarios defined in the Phase I report;
- Case studies to represent the most suitable candidates in the APEC economies for reducing CO_2 emissions based on their present and planned generation mix;
- Case studies to demonstrate significant to large greenhouse reductions from a single plant or from multiples of similar plants;
- Coverage of both developing and developed economies;
- Case studies to illustrate different political and economic conditions (eg examples from both monopoly and competitive markets);
- Case studies to be applicable to a high proportion of developing APEC economies;
- Case studies to cover the range of fuel types (coal, natural gas, oil as well as biomass);
- Low cost of abatement (\$/t CO_2);
- Advanced technology examples to show the potential future direction for CO_2 reduction.

The case studies that satisfied the above criteria are briefly described below, arranged according to the four Basic Categories, as defined in the Phase I Report.

All efficiency data given below are on a higher heating value (HHV) basis.

Power Station Upgrade (3 case studies)

- **Malaya Power Station, Philippines** Rehabilitation of 1970's vintage oil-fired thermal power station back to rated cycle efficiency and capacity. Efficiency increased from 30.9% to 35.1% and capacity increased from 430 to 650 MW.
  Emission Reduction Scenario : E1

- **Banshan Coal Fired Power Station, China** Rehabilitation of older coal-fired plant, resulting in an increase in overall cycle efficiency from 33.9% to 38.5% and output from 125 to 135 MW.
  Emission Reduction Scenario: E4

- **Liddell Power Station, Australia** Replacement of low pressure (LP) turbine in coal-fired power station, increasing efficiency by 3 %.
  Emission Reduction Scenario: E4

Co-fire / Fuel Switching (2 case studies)

- **Lanzhou City, China** Suite of measures to reduce pollution and improve energy efficiency. Includes conversion of coal-fired to natural gas-fired power plant, construction of a natural gas-fired power station and switch from multiple coal-fired boilers for central heating to natural gas-fired centralised cogeneration plant.
  Emission Reduction Scenario : E10

- **Macquarie Generation, Liddell and Bayswater Power Stations, Australia** Co-firing of up to 5% biomass in two black coal-fired power stations.
  Emission Reduction Scenario: No Good Fit

Repowering (5 case studies)

- **Astoria Generating Station, United States** Repowering of fuel oil- / natural gas-fired thermal boilers with GTCC using natural gas, utilising much of the existing plant infrastructure (including existing steam turbine / generators and condenser) increasing power generation from 1,254 to 1,816 MW with a large reduction in greenhouse intensity.
  Emission Reduction Scenario : E12

- **Chita Power Station, Japan** Repowering of six units of Chita and Chita No. 2 Thermal Power Stations (1966 to 1983 vintage thermal plant) to fully-fired combined-cycle units by adding a gas turbine to the existing boiler - steam turbine generator, increasing power generation and efficiency.
  Emission Reduction Scenario: E12

- **Senoko Power, Singapore** Conversion of gas turbine plant from open- to combined-cycle operation, increasing power generation from 524 to 850 MW with the same fuel demand, and increasing the efficiency from 28.3% to 45.9%.
  Emission Reduction Scenario : E13

- **Yonghung Supercritical Power Plant, Korea** 2 x 800 MW supercritical coal-fired power plant with a plant efficiency of 43.5%, due for completion in 2004.
  Emission Reduction Scenario : E14

- **Wabash River Coal Gasification Repowering Project, United States** Repowering of a 1950's vintage 90 MW coal-fired thermal plant with Destec's coal gasification technology and syngas-fired combustion turbine to provide 262 MW of power, increasing efficiency from 33% to 40%.
  Emission Reduction Scenario : E17

Combined Heat and Power, or Co-generation (1 case study)

- **Map Ta Phut Hybrid Co-Generation, Thailand** 514 MWe and 2 x 100 tph steam cogeneration units using a highly innovative hybrid cycle which can use gas and coal as fuel.
  Emission Reduction Scenario : E18 / E19

3.4 References

Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region, Prepared for APEC Energy Working Group, Expert Group on Clean Fossil Energy, Prepared by Levelton Engineering Ltd, November 2001.

3.5 Glossary

AFBC	Atmospheric Fluidised Bed Combustor
APEC	Asia-Pacific Economic Cooperation
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
GTCC	Gas Turbine Combined-Cycle
HHV	Higher Heating Value
IGCC	Integrated Gasification Combined-Cycle
IP	Intermediate Pressure
kW	Kilo Watt
MW	Mega Watt
MWe	Mega Watt Electrical
MWhr	Mega Watt Hour
O&M	Operating and Maintenance
PC	Pulverised Coal
PFBCC	Pressurised Fluidised Bed Combined-Cycle
tph	Tonnes per Hour

4. CASE STUDIES FOR CO_2 REDUCTION OPTIONS

4.1 Malaya Thermal Power Station Rehabilitation

Phase I Basic Category : Power Station Upgrade
Phase I Emission Reduction Scenario : E1

4.1.1 Project Description

Power Station

The 650 MW Malaya Thermal Power Station is located on Luzon Island, 60 km from Manila in the Philippines. The conventional oil-fired power station consists of Unit 1, rated at 300 MW, and Unit 2 rated at 350 MW. Unit 1 commenced commercial operation in 1975, and Unit 2 in 1979.

Since construction, the plant performance, output and efficiency of the power station had fallen. In 1995 Korea Electric Power Corp. (KEPCO) were awarded the contract to rehabilitate the power station, under an own and operate arrangement as an independent power producer.

Plant Modification

Rehabilitation of the Malaya plant was completed in 1998. This resulted in an increase in total generation from 430 to 650 MW (back to its original rated capacity), and an overall increase in efficiency from 30.8% to 35.6%.

A summary of works that directly improved the operating efficiency are given below :

Boiler
- replacement of main boiler tubes, superheater and auxiliary boiler tubes (Unit 1);
- replacement of furnace hopper tubes (Unit 2);
- installation of 6 additional sets of retractable soot blowers (Unit 1);
- rehabilitation of boiler air fans (Units 1 and 2);
- adjustment of burners for optimal flame and tube temperatures and boiler optimisation trials (Units 1 and 2);
- replacement of air pre-heater seal and elements to reduce air leakage and to increase the boiler efficiency (Units 1 and 2);
- replacement of gas duct and fixing of all boiler air ingress points (Units 1 and 2);
- stabilisation of boiler feed water heater system by normalising level control, which used to control level by opening emergency drain valves (Units 1 and 2);
- installation of automatic burner management control system (Units 1 and 2).

Turbine, Generator and Condenser
- replacement of intermediate pressure (IP) turbine rotor (Unit 1);
- rehabilitation and replacement of generator core and exciter (Units 1 and 2);
- rehabilitation of main turbine and high voltage motor pumps (Unit 2);
- replacement of turbine seals and damaged blades to increase efficiency (Units 1 and 2);
- retubing of condensers to increase vacuum level (Units 1 and 2).

Consequent Emission Reduction

Table 2 : Efficiency Improvement Achieved

	Unit 1	Unit 2	Overall
On Turn Over Date			
Capacity, MW	180 MW	250 MW	430 MW
Efficiency, %	28.8%	32.4%	30.9%
Greenhouse Intensity, kg CO_2 / MWhr	914	811	851
After Rehabilitation			
Capacity, MW	300 MW	350 MW	650 MW
Efficiency, %	34.5%	35.7%	35.1%
Greenhouse Intensity, kg CO_2 / MWhr	761	737	748
Improvement			
Capacity Improvement, MW	120 MW	100 MW	220 MW
Efficiency Improvement, % points	5.8%	3.2%	4.7%
Relative Efficiency Improvement, %	20.1%	10.0%	13.8%

Rehabilitation of the plant has resulted in a 220 MW increase in power generation capacity (up 51%), an improvement in overall efficiency of 4.7 percentage points or 13.8%, with a reduction in greenhouse gas intensity by 103 kg CO_2 / MWhr (down 12%).

Based on a 80% available capacity factor greenhouse emissions would actually increase from 2.56 to 3.41 million tonnes of CO_2 per annum due to the increase in power generation. However, the emission savings if the upgraded plant was generating at the greenhouse intensity prior to the upgrade is 470 kt CO_2 per annum.

Other Environmental Benefits

KEPCO invested US$ 7.3 million for rehabilitation and new installation of environmental facilities for water treatment, noise reduction and waste management. A waste water treatment plant was installed to treat all waste water from the power plant, reducing discharged pollutant concentration to one quarter of limits designated by the Philippines Government.

KEPCO replaced the cyclone dust collectors to comply with the Philippine emission standard for particulate matter. In addition, the newly installed automatic boiler control system was designed to minimise NO_x. SO_x emission was reduced by burning low sulphur Bunker-C oil.

The ash handling system was changed from wet to dry type to reduce water pollution and to the improve the management of solid waste handling.

KEPCO also installed four silencers on each of the high pressure safety valves to reduce noise.

4.1.2 Financial Cost

Implementation Cost

The total cost of rehabilitating the plant was US$ 160 million (plus an additional deposit of US$ 100 million for the power station purchase). This corresponds to US$ 727 / kW for the 220 MW of increased capacity (excluding the power plant purchase cost).

Operating Cost

The investment in refurbishing the plant has resulted in a substantial reduction in the maintenance cost and with a corresponding reduction in forced outage hours. The availability factor has increased from 66% in 1996 to between 94.5 and 99.9 % in 2001, 2002 and for the first half of 2003.

Abatement Cost

The abatement cost (US$ / t CO_2) has been estimated by calculating an overall annual cost (annualised capital cost - savings in operating cost) and dividing by the annual abatement. The calculations compare the fuel demand and emissions for the refurbished plant and a theoretical fuel demand and emissions at the refurbished plant's output operating at the old plant's efficiency. The fuel savings exceeds the annualised capital cost, giving a US$ 5.4 / t CO_2 abatement 'benefit'.

Table 3

	Units	
Reduction in Operating Cost		
Annual Fuel Cost Savings	US $M / yr	21.3
Reduction in Operating and Maintenance Cost	US $M / yr	0.0
Overall	US $M / yr	21.3
Capital Cost		
Capital Cost of Refurbishment	US $M	160
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	18.8
CO_2 Abatement Cost		
Overall Annual Cost	US$ M / yr	-
Annual CO_2 Abatement	kt CO_2	470
Cost of Abatement	US$ / t CO_2	-5.4

Project Finance

The project financial arrangements were comprised of a debt of US$ 170 million, including a deposit of US$ 100 million (for the plant purchase), with US$ 90 million of equity. The lenders were Bank of Tokyo-Mitsubishi, Citibank N A (Hong Kong), Korea Development Bank, Norinchukin Bank (Japan), Nippon Life Insurance and seven other banks.

4.1.3 Key Factors

The refurbishment and operation of the Malaya Thermal Power Plant in the Philippines was KEPCO's first participation into overseas power generation market. KEPCO used the experience of rehabilitating a number of their own older thermal power plants, including Yosu 1 and 2, Ulsan 1 - 3, Youngnam 1, Busan 3 - 4 and Inchon 1 Power Plants, that were built in the late 1960's and early 1970's and were rehabilitated in the late 1980's and early 1990's. This experience, together with extensive operation and maintenance management know-how ensured a successful rehabilitation project.

KEPCO were also able to draw on resources within its organisation and within several subsidiaries such as KOPEC (Korea Power Engineering Company), KEPRI (KEPCO's Korea Electric Power Research Institute).

Enabling Factors

The sale of the Malaya Power Plant was the first stage of the break-up and privatisation of the National Power Corporation (NAPOCOR) and the facilitation of foreign and private-sector investments into the industry. Power stations approaching the end of their design life expectancy are being offered to private companies in 'rehabilitate, operate, maintain and manage' contracts. The contact arrangements with NAPOCOR are also on an Energy Conversion Agreement (ECA) basis - whereby NAPOCOR supplies the fuel, and purchase the power.

Resistance to Implementation

There was some internal resistance within the management of KEPCO to embarking on its first overseas venture that needed to be overcome.

KEPCO had no difficulties in financing the project, due to its financial strength as a state-owned monopoly in Korea. Similarly, access to technology was not an issue.

Role of Government

The Korean Government with majority voting rights of KEPCO's Board of Directors was firmly in favour of pursuing the investment.

The Philippine Government role was pivotal in setting up the Enactment of Emergency Law for Electricity Supply, such as the Build Own Transfer Law and the Electric Power Crisis Act of 1993. These laws opened the way for Independent Power Producers (IPPs) to invest in the previously state owned monopoly, rapidly averting the power crisis (due to under-supply) that hit the Philippines in the 1990's.

Role of Private Sector

There was very little involvement from the private sector, apart from the provision of technical services to assist in completing the rehabilitation project.

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4.2 Banshan Power Station Improvement Project

Phase I Basic Category : Power Station Upgrade
Phase I Emission Reduction Scenario : E4

4.2.1 Project Description

While many power generation technologies are mature there are still significant improvements in detail over time. These improvements enable the achievement of higher in plant efficiency and consequent reduction in greenhouse gas release when an older unit is reviewed and refurbished in an economical manner.

Each older power station must be reviewed on a case by case basis to determine the most cost effective remedial action. Performance improvements of up to 5% are quite possible. The performance of Banshan Power Station was reviewed, improvement proposals made to management and then successfully implemented resulting in an improvement in overall cycle efficiency from 33.9 to 38.5% (HHV).

The project represented a cooperative effort by the Australian Government, Pacific Power International, Rio Tinto Resources and the Zhejiang Provincial Electric Power Company (ZPEPC).

Power Station

Banshan Power station is an older coal-fired facility in Hangzhou, the capital of Zhejiang province in PR China. It is owned by the Zhejiang Provincial Electric Power Company. The unit selected for study was a 125 MW coal-fired subcritical boiler and turbine commissioned in 1985.

In 1997 this cooperative project was conducted jointly by Pacific Power International (PPI), ZPEPC and Rio Tinto Resources with significant funding by the Australian Government Department of Industry, Science and Resources.

This project sought cost-effective ways of improving plant performance from an holistic analysis. This minimises the likelihood of suggesting modifications with little overall effect on the unit.

It was typical of more than 100 similar units in PR China, acting as a demonstration of what could be achieved with economic refurbishment.

Plant Modifications

This excellent project demonstrated cooperation between APEC economy governments in reviewing the possibility of refurbishing an older coal-fired power station unit, proceeding with the recommended upgrade and then measuring the improvement in performance and abatement.

The following plant improvements were proposed on the basis of recovering costs within four years. The review recommended a complete turbine upgrade as proposed by the manufacturer with the option of installing a digital electro-hydraulic governor.

The proposed boiler improvements included reinstatement of the sootblowers and burner tilt mechanism, reduction in excess air, furnace remodelling to reduce unburnt carbon loss, improvement of mill maintenance and air heater upgrading.

A complete upgrade of the unit control system including extra control circuits was recommended.

The coal supply was also reviewed with a potential reduction in operating cost using a blend of Australian and Chinese coals. It was found that a blend of Australian and local coal in a ratio 2:1 could give an operational saving of US$ 2.60 / t used. This took advantage of the lower mill wear and combustion performance of the Australian coal, combined with the improved performance of the electrostatic precipitators with the Chinese coal (due to ash properties).

The plant modifications were carried out in 1999 and 2000 to test the effectiveness of the evaluation process and as a demonstration of the potential benefits of implementation for other similar plants.

The modifications resulted in performance improvements that were generally greater than had been predicted. Overall unit efficiency rose from 33.9% to 38.5% (HHV). Boiler efficiency increased from 85.5% to 89.1% (HHV) with corresponding reductions in draught losses and unburnt carbon. Turbine efficiency improvement was initially estimated at 5.4% but actually 9.2% was achieved. This resulted in an overall reduction in coal consumption of about 13.7%.

Unit output was improved from 125 to 135 MW. The control system improvements contributed to this improvement and also allowed a reduction in staff numbers. Additionally, plant history files were set-up to enable ongoing monitoring of performance.

Consequent Emission Reduction

From an analysis of the various improvements and for an available capacity factor of 70%, there is a reduction in emissions from 928 to 883 kt CO_2 / annum (a saving of 45 kt CO_2 / annum). The greenhouse gas intensity is reduced from 1,211 kg CO_2 / MWhr to an estimated 1,066 kg CO_2 / MWhr. The emission savings if the upgraded plant was generating at the old greenhouse intensity are 120 kt CO_2 per annum.

A further reduction of about 30 kt CO_2 per annum could be achieved through using a 2:1 blend of Australian to locally mined coal respectively, further reducing the greenhouse gas intensity to about 1,030 kg CO_2 / MWhr.

Other Environmental Benefits

The project resulted in a significant reduction in NO_x emission from boiler improvements and a reduction in SO_x where Australian low sulphur coal was blended into the mix.

4.2.2 Financial Investment

Implementation Cost

The refurbishment costs were US$ 3.5 million. The project is expected to pay for itself in between three and four years from increased output and decreased operating and coal costs.

The cost corresponds to US$ 438 / kW for the 10 MW of increased capacity following refurbishment.

Operating Cost

A 13.7% reduction in coal consumption was achieved together with reduced unburnt carbon and draft losses. Some reduction in staff levels was also possible.

Abatement Cost

The abatement cost (US$ / t CO_2) has been estimated by calculating an overall annual cost (annualised capital cost - savings in operating cost) and dividing by the annual abatement. The calculations compare the fuel demand and emissions for the refurbished plant and a theoretical fuel demand and emissions at the refurbished plant's output operating at the old plant's efficiency. The fuel savings exceeds the annualised capital cost, giving a US$ 4.8 / t CO_2 abatement 'benefit'.

Table 4

	Units	
Reduction in Operating Cost		
Annual Fuel Cost Savings	US $M / yr	0.99
Reduction in Operating and Maintenance Cost	US $M / yr	0
Overall	US $M / yr	0.99
Capital Cost		
Capital Cost of Refurbishment	US $M	3.5
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	0.41
CO_2 Abatement Cost		
Overall Annual Cost	US$ M / yr	-0.58
Annual CO_2 Abatement	kt CO_2	120
Cost of Abatement	US$ / t CO_2	-4.8

Project Finance

Project finance for the review stage was provided by the Australian Government, ZPEPC and Rio Tinto. Finance for the execution stage was provided by ZPEPC.

4.2.3 Key Factors

Enabling Factors

Probably the main enabling factor was the willingness of government and private companies to work together to improve an old coal-fired power station to act as a real demonstration for others to inspect and follow.

Resistance to Implementation

The local authorities in Hangzhou were enthusiastic and no major barriers were encountered.

Role of Government

The Australian Government was interested in finding a suitable older coal-fired power station unit whose performance could be reviewed and necessary improvements proposed to improve efficiency and improve greenhouse gas abatement.

It used the services of Pacific Power International to link with the ZPEPC power company in Zhejiang Province and then review refurbishment alternatives.

Role of Private Sector

While not strictly private sector, the local government in Zhejiang Province and ZPEPC were interested in cooperating in a project to improve plant efficiency.

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4.3 Liddell Power Station, Turbine Blade Replacement

Phase I Basic Category : Power Station Upgrade
Phase I Emission Reduction Scenario : E4

4.3.1 Project Description

Present power generation technologies are generally mature but even with mature status there are significant improvements over the life of a coal-fired power station that can be effective when considering refurbishment.

Probably the major single improvement in efficiency over the last twenty years has been in blade design for large steam turbines. This has been coupled with improved economic methods of making the more complex blade shapes to bring the cost within the limitations of a turbine refurbishment project. As a result, an efficiency gain of 2-3% can be predicted with some confidence for replacement of the turbine low pressure (LP) cylinder of an older unit, with rather less gain for replacement of the intermediate pressure (IP) cylinder in a large machine.

Power Station

Liddell Power Station has four 500 MW coal-fired units in the Hunter Valley in New South Wales, Australia. It was commissioned between 1971 and 1973. Liddell is part of Macquarie Generation (MG) a state owned corporation formed in 1996. Macquarie Generation competes in the National Electricity Market (NEM).

These units have English Electric turbines with blade design of about 1960 vintage. As part of refurbishing these units the replacement of turbine cylinders / blades was considered. The existing blades had some damage in the LP cylinder but insufficient to necessitate renewal.

The Australian Greenhouse Office (AGO) was offering, through the Greenhouse Gas Abatement Program (GGAP), to bridge the funding gap for otherwise uneconomic plant improvement projects that had large greenhouse abatement potential. A GGAP grant was sought to cover the financial shortfall and was granted by the government. This resulted in a contribution of AU$ 5 million (US$ 3.25 million) towards LP cylinder replacement for the four turbines costing AU$ 52 million (US$ 34 million).

Replacement blades were delivered, the first unit has been modified and improvement has exceeded expectations. The target efficiency improvement of 3% was reached. The remaining units will be modified by 2005.

Plant Modifications

The main plant modification was the replacement of the LP turbine on every one of the four units. At the same time the unit analogue control system was replaced with the latest digital control system, improving performance even further.

Consequent Emission Reduction

A reduction of 300,000 t CO_2 per annum for the four units was confirmed from tests on the first installation. This is a reduction of 3% over the remaining life of the units. The efficiency of the power station increases from 32.7% to 33.7%, with a reduction in greenhouse intensity from an estimated value of 969 kg CO_2 / MWhr to 941 kg CO_2 / MWhr.

Other Environmental Benefits

This modification is specific to the turbine and no other emission improvements are expected.

4.3.2 Financial Investment

Implementation Cost

The total cost of replacing the LP cylinders on four units was US$ 34 million. The AGO contributed US$ 3.25 million towards the project to make it financially viable. An additional US$ 13 million was invested by Macquarie Generation in the unit digital control systems. Overall capacity of the station was increased by 60 MW (a cost of US$ 780 / kW for the 60 MW of additional power generation).

Operating Cost

This plant improvement will reduce the coal consumption of the units over the next twenty years.

Abatement Cost

The abatement costs with and without AGO funding are given in Table 5. For the IRR assumptions used, without AGO funding, the project is not economically viable in its own right, giving an abatement cost of $ US 0.56 / t CO_2. With AGO funding, the project becomes economic, giving an abatement benefit of $ US 0.71 / t CO_2.

Table 5

	Units	Without AGO Funding	With AGO Funding
Change in Operating Cost and Revenue			
Annual Fuel Cost Savings	US $M / yr	0	0
Annual Power Generation Revenue Increase	US $M / yr	3.83	3.83
Reduction in Operating and Maintenance Cost	US $M / yr	0	0
Overall	US $M / yr	3.83	3.83
Capital Cost			
Capital Cost of Turbine Upgrades	US $M	34.00	30.75
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	3.99	3.61
CO_2 Abatement Cost			
Overall Annual Cost	US$ M / yr	0.17	-0.21
Annual CO_2 Abatement	kt CO_2	300	300
Cost of Abatement	US$ / t CO_2	0.56	-0.71

Project Finance

Macquarie Generation funded the plant improvement from internal resources. No loans were required.

4.3.3 Key Factors

Enabling Factors

The first enabling factor was the existence of the NEM and the necessity for rigorous review of any expenditure for plant improvement in a competitive electricity market. This review indicated that expenditure on replacement of LP cylinders was not quite economic.

The second enabling factor was the availability of government funds through a competitive process to bridge the gap and make the project economically viable on the basis of its greenhouse abatement potential.

Resistance to Implementation

There was no other resistance to the project as it fulfilled the GGAP requirements.

Role of Government

The Australian Government has played a key role in making this contribution to greenhouse gas mitigation possible. The Australian Greenhouse Office (AGO) was formed in 1998, the world's first government agency dedicated to reducing greenhouse gas emissions. This provides an integrated government approach to greenhouse matters.

The AGO has developed a number of innovative programs providing assistance in greenhouse abatement. One of these programs is the Greenhouse Gas Abatement Program (GGAP). This provides financial assistance to projects that are not economically viable in their own right but the addition of limited funding would make them attractive commercially. These projects must demonstrate an abatement of at least 250,000 t CO_2 per annum. Suitable projects are selected from a competitive process.

Role of Private Sector

Macquarie Generation operates within the NEM and must compete on a sound financial basis. Conventional economic decisions prevented investment in turbine refurbishment until adequate government funding was available from the GGAP.

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4.4 Lanzhou City Case Study, Reduction in CO_2 and Environmental Emissions

Phase I Basic Category : Co-firing / Fuel Switching
Phase I Emission Reduction Scenario : E10

4.4.1 Project Description

Lanzhou City is in north west China's Gansu Province, on the Loess Plateau at an altitude of 1,500 - 2,000 m above sea level, and has a population of 2.9 million people. The city has been heavily dependent upon coal as its source of energy for power generation and heating. Power for the city is generated mainly (80%) by conventional coal-fired boilers. In addition, heating is required for 5 months of the year, and is supplied by 1,159 low efficiency coal-fired boiler houses (32% are large central-heating boilers, and the remainder, 68% are small local boilers).

The city is in a very hilly area, with little wind all year round. In winter there is often an intensified inversion layer up to 700 m thick. The World Health Organisation has listed Lanzhou as one of the world's 10 worst polluted cities.

Infrastructure Upgrading

The environmental issues are being addressed as a result of the following infrastructure development projects :

- Construction of the Sebei to Lanzhou natural gas pipeline (completed in 2001);
- Construction of Lanzhou Power Plant, a 4 x 300 MW gas-fired turbine combined-cycle plant;
- Conversion of the Xigu power plant from coal-fired to natural gas-fired;
- Construction of a number of larger central heating boilers and shutting down of smaller local boilers for heating;
- Upgrade of province's power grid infra-structure.

Plant Design and Modification

Gansu Power, a wholly owned subsidiary of State Power Company (SPC), is constructing Lanzhou Power Plant (in conjunction with Siemens), which will be a 4 x 300 MW gas-fired gas turbine combined-cycle power plant. The project will use natural gas from the neighbouring Qinghai Province and Xianjiang Uygar Autonomous Region using the recently constructed 930 km natural gas pipe-line from Sebei to Lanzhou.

Gansu Power, in conjunction with Siemens will also convert the Xigu coal-fired to natural gas-fired thermal power plant (approved in July 2002). In addition, three power grid construction projects will improve the province's power grid infra-structure and the reliability of the power supply.

The local government of Lanzhou is also increasing the number of larger central-heating boilers and have an established program to close down the smaller low efficiency boilers. A 98 km long heat supply piping network will transmit heat from Xigu Heat and Power Plant from the East to the West sections of Lanzhou. When the project is complete the central heating system will take the place of more than 600 boilers, saving 27,000 tpa of fuel coal, and 3,200 of sulphur dioxide and will dramatically reduce the smog in the city.

Environmental Benefits

The combustion of coal in Lanzhou has resulted in the release of large quantities of particulates, SO_x, NO_x and other pollutants. The World Health Organisation has listed Lanzhou as one of the world's 10 worst polluted cities. In 1999 the TSP (total suspended solids) were 0.66 mg/m^3, or 2.3 times the National Air Quality Standard. No data was available as to the expected reduction in CO_2 emissions from the infrastructure projects.

4.4.2 Financial Cost

Implementation Cost

There are a number of costs associated with the infrastructure upgrades :

- Natural gas pipeline infrastructure cost from Sebei to Lanzhou (2.5 billion yuan or US$ 301 million);
- Construction of three 330 kV power lines (687 million yuan or US$ 83 million);
- Construction of Lanzhou Power Plant (6 billion yuan or US$ 723 million) at an installed cost of US$ 602 / kW for the combined-cycle plant;
- Conversion of Xigu power station from coal to natural gas (1.3 billion yuan or US$ 157 million);
- Conversion of locally fired boilers to gas-fired and construction of larger central heating boilers (600 million yuan or US$ 72 million for the construction of a 98 km long heat supply network from Xigu Heat and Power Plant).

Currency conversion is based on 8.30 yuan per US$. The total cost for the infrastructure upgrades are 11.1 billion yuan or about US$ 1.34 billion.

Project Finance

The construction of the Lanzhou Power Plant and the conversion of the Xigu Power Plant are to be jointly financed by Siemens and Gansu Province.

4.4.3 Key Factors

Enabling Factors

The natural gas transport pipeline from Sebei (in Qinghai province) to Lanzhou was completed in 2001 as part of the West-Gas-to-East Project, a 4,200 km pipeline to convey natural gas from Tamin Basin to Shanghai. This major infrastructure project has allowed the construction of natural gas-fired gas turbine combined-cycle Lanzhou Power Plant and the conversion of coal-fired to natural gas-fired Xigu thermal power station.

Role of Government

The Local and State Governments have had pivotal roles through major infrastructure development, encouraging foreign investment and through local schemes such as the shutting down of smaller coal-fired boilers and the construction of larger, more efficient central heating boilers. This effort was part of a Central Government plan in which Local Governments must reduce pollution levels for 49 targeted cities to 1995 levels by 2000 with factories that don't meet the standards being shut down.

Role of Private Sector

A key enabling factor has been the ability of the power sector in Gansu to encourage foreign investment (with the involvement of Siemens) in constructing, upgrading and having equity in power stations in Lanzhou. This has been in part been bolstered by planned increases in power prices, that until recently were the lowest in China.

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4.5 Macquarie Generation, Biomass Co-Firing with Coal

Phase I Basic Category : Co-firing / Fuel Switching
Phase I Emission Reduction Scenario : No Good Fit

4.5.1 Project Description

Biomass co-firing is a method of reducing the proportion of fossil carbon in conventional coal-fired power stations. The same quantity of carbon is used for power generation but some of it is considered to be from a renewable resource. The reduction in greenhouse gas is a function of the proportion of biomass used.

Biomass is a low energy density, high moisture material compared with coal so the proportion of biomass that can be substituted for coal is limited by a number of factors. In a conventional pulverised coal-fired boiler the proportion of biomass substituted can generally be up to 10% of nominal capacity without significant loss of unit capacity.

Biomass may be injected into the furnace using its own burner but more frequently it is mixed with coal fed to the pulverisers and injected with the pulverised coal in the normal burners.

The largest particle size and particle size distribution of the biomass and its moisture content are critical operational factors. Biomass is generally considered to be a ductile material while coal is brittle. Brittle and ductile materials require quite different types of grinding to reduce their particle size so that burnout is essentially complete within the boiler furnace.

If the coal-fired boiler has high speed coal pulverisers then biomass can generally be processed easily, either for separate burner injection or combined with coal. These mills provide the necessary shredding action to break up the biomass.

Most boilers have medium speed mills that are not designed for shredding. Biomass in the form of large lumps or strips cannot be processed. Biomass in the form of sawdust like material can be added up to 5% of the mill capacity providing the moisture drying capacity of the mill is not exceeded.

Some boilers have low speed mills that do not handle biomass effectively because of the grinding action and the low moisture dying capacity of this type of mill. The use of biomass is very much on a case-by-case basis because of its diverse nature. This case study provides an example of the utilisation of sawdust from a timber sawmill.

Combustion of biomass mixed with pulverised coal within a large coal-fired boiler generally releases little or no dioxins or other carcinogenic compounds normally arising from incomplete combustion.

Power Station

Macquarie Generation has two large coal-fired power stations in the Hunter Valley in New South Wales, Australia. Bayswater Power Station (BPS) has four 660 MW units and Liddell Power Station (LPS) has four 500 MW units.

Liddell has co-fired up to 5% biomass with coal for some years. Biomass consumption has been variable, depending on availability of suitable material. It aimed to produce about 100 GWhr of power per annum from this resource.

Various forms of biomass were available in varying quantities in the Hunter Valley from different crops and from the local sawmilling industry. This project has concentrated on utilising untreated timber by products such as sawdust. This material is available in limited quantities and does not have to be ground significantly to mix with normal coal fed to the plant coal pulverisers.

LPS has medium speed mills that have demonstrated that they can process up to 5% of fine wood waste, in this case sawdust which is approximately spherical with a particle size of 1 mm to 3 mm. The drying capacity of the milling plant is not exceeded.

BPS has low speed ball mills that have demonstrated that they can process much smaller quantities of fine wood waste biomass because of the brittle/ductile problem and the reduced drying capacity of this type of mill.

The environmental licence for the power stations was renegotiated to include combustion of up to 5% biomass. A number of test burns were carried out in 1999 with varying concentrations of sawdust in the coal. The main advantage in utilising sawdust in a large coal-fired furnace is the reduced likelihood of producing dioxins and other carcinogenic products of incomplete combustion.

Wood waste normally is available at no cost to Macquarie Generation. The power station incurs a transport cost to bring the material to the power station. Deliveries are monitored to provide proof of use of biomass.

Plant Modification

Very little plant modification was necessary. This was limited to the provision of biomass storage hoppers adjacent to the coal handling plant to receive biomass from a number of sources.

Consequent Emission Reduction

The co-firing of biomass at the two stations saves about 100,000 t of CO_2 per annum. Total biomass combustion from August 1999 to February 2003 is shown below with tonnage of biomass, the resulting power generated from biomass combustion and the quantity of coal replaced.

Table 6 : Emission Reduction at Power Stations

	Bayswater Power Station	Liddell Power Station	Total
Biomass, t	35,285	258,429	293,714
Power, MWhr	39,827	249,491	289,318
Coal Replaced, t	18,698	131,116	149,814

Based on 2001 - 2002 generation data, the Bayswater and Liddell power stations had a weighted average generation efficiency of 34.5%, giving a greenhouse intensity of about 917 kg CO_2 / MWhr. An annual saving of 100,000 t CO_2 from burning biomass would reduce the greenhouse emissions by about 0.44%, and the greenhouse intensity to 913 kg CO_2 / MWhr.

Other Environmental Benefits

Plant emissions are monitored regularly and there are no deleterious emissions such as dioxins.

4.5.2 Financial Investment

Implementation Cost

Implementation costs for the firing of biomass were relatively low. A resource survey was required to determine the availability of adequate reserves of biomass at an acceptable overall cost including transport to the station. Simple biomass storage hoppers were installed adjacent to the coal handling plant at relatively low cost.

Operating Cost

The biomass resource is a diverse mixture of different products available in variable quantities from locations up to 50 km from the power station. Operating costs are limited to transport cost of wood waste from a number of local resources. Biomass is purchased, transported and utilised at a cost less than the prevailing cost of an equivalent Renewable Energy Certificate described below.

Abatement Cost

The increase in power generation revenue (from RECs - see Section 4.5.3) is substantially higher than the annualised capital cost (indicating that combustion of biomass is economic in its own right), giving a US$ 17.4 / t CO_2 abatement ‘benefit’. Without RECs revenue, the benefit is reduced to US$ 1.7 / t CO_2.

Table 7

	Units	Without RECs	With RECs
Change in Operating Cost and Revenue			
Annual Fuel Cost Savings	US $M / yr	0.194	0.194
Annual Power Generation Revenue Increase	US $M / yr	0	1.577
Reduction in Operating and Maintenance Cost	US $M / yr	-0.010	-0.010
Overall	US $M / yr	0.184	1.761
Capital Cost			
Capital Cost	US $M	0.150	0.150
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	0.018	0.018
CO_2 Abatement Cost			
Overall Annual Cost	US$ M / yr	-0.166	-1.743
Annual CO_2 Abatement	kt CO_2	100	100
Cost of Abatement	US$ / t CO_2	-1.7	-17.4

Project Finance

The necessary finance was included in normal operation. No project finance was necessary.

4.5.3 Key Factors

Enabling Factors

The key enabling factors were the availability of local supplies of biomass at no cost and the suitability of the coal pulverisers at LPS to handle the biomass. Some biomass was processed at BPS but not as effectively. This shows the importance of type of coal pulveriser and the need for a case by case review before consideration of biomass co-firing.

Resistance to Implementation

There was no real resistance to implementation. However there was consultation at all times with the Macquarie Generation Community Consultative Group.

Role of Government

The Australian Government has played a key role in making this contribution to greenhouse gas mitigation possible. While the Australian Government has not ratified the Kyoto Protocol it has committed to reach the greenhouse goals negotiated under the Protocol.

To this end in 1998 it formed the Australian Greenhouse Office (AGO), the world’s first government agency dedicated to reducing greenhouse gas emissions. This provides an integrated government approach to greenhouse matters.

The AGO was generously funded and developed a number of innovative programs providing assistance in abatement. One of these programs is the Mandatory Renewable Energy Target (MRET). This requires the generation of 9,500 GWhr of extra renewable energy per year by 2010. The Office of the Renewable Energy Regulator (ORER) has been established to oversee the implementation of the measure.

This program puts a legal liability on wholesale purchasers of electricity to proportionately contribute towards the generation of an additional 9,500 GWhr per annum. Liable parties will be required to obey their obligations under the target. They need to surrender Renewable Energy Certificates (RECs) equal to their requirement which will then be cancelled. Certificates can be derived from contracts with renewable energy generators or by trading certificates at a negotiated price in the market.

RECs are created from accredited renewable energy generation from eligible renewable energy assets. They can be traded in a financial market. Acceptable energy resources for generating RECs include bagasse, wood waste and crop waste.

This project uses wood waste in the form of sawdust from a number of local sawmills to blend with coal and fire in an existing boiler. RECs are formed from the proportion of generation where coal is replaced by wood waste.

The value of a REC is a function of the market at any time. They are presently exchanged at AU$ 28 - 30 / MWhr (US$ 18.2 - 19.5 / MWhr). International sales of Green Warrants have been also been sold to a Japanese company arising from the biomass co-firing program.

Role of Private Sector

In 1992 the Council of Australian Governments (COAG) made up of federal and state governments agreed to a plan to bring competition to a number of monopoly industries including the power supply industry. The National Electricity Market (NEM) commenced operation in a limited sense in 1996 and has expanded ever since.

Organisations competing in the NEM may be government-owned, semi-government owned or private. All have to obey the same set of rules. They need to incur profits where possible for their shareholders, whether private or taxpayer. As a consequence costs are controlled and investment in projects such as MRET, are carried out on a profitable basis.

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4.6 Astoria Repowering Project, Reliant Energy

Phase I Basic Category : Repowering
Phase I Emission Reduction Scenario : E12

4.6.1 Project Description

The Astoria Repowering Project will occupy a 19 acre area situated within the 318 acres of the Consolidated Edison site in Queens, New York. The Consolidated Edison site has been the location for manufacturing and heavy industry for over a hundred years. While repowering the facility, the project also seeks to bring state of the art generation technology and emissions controls to the refurbished plant. The new facility will provide an additional 562 MW to the power grid whilst dramatically improving generating efficiency and reducing greenhouse and other emissions to the environment.

The past few years have been a period of dramatic change in the United States power and energy industry. The stockmarket crash and economic conditions have led to numerous company changes and restructures. The Astoria Repowering Project was originally conceived by Orion Power that, after a restructuring of major debt of US$ 1.57 billion, was acquired by Reliant Energy on February 19, 2002. The difficult economic and industry conditions has delayed the commencement of construction of the project. Reliant Energy remain committed to the project, but are continuing debt restructuring and state that "*Commencement is dependent on both the ability of Reliant to secure a long-term purchased power agreement and the strengthening of the company's debt rating*."

The original project timeline envisaged commencement of demolition and removal works in late 2002, with project completion in 42 months. Project completion is now expected to be six years from commencement of construction.

Description of Plant

The original plant consisted of 5 generating units operated by Consolidated Edison. Units 1 and 2 were decommissioned in 1993. Orion Power purchased the generating facility in 1999. Orion recommissioned Unit 2 as a natural gas-fired steam electric power plant in September 2000. The existing operational plant consists of 4 generating units burning low sulphur fuel oil and natural gas and the re-commissioned 175 MWe natural gas-fired steam electric power plant Unit 2 burning natural gas only. The existing boilers produce steam at a pressure of about 2,000 psi and 565 °C. Under the current operating profile the thermal efficiency of these units ranges from 32.0% to 34.5% (ISO). The existing plant has a nominal total output of 1,254 MWe.

The existing operational generation units are as follows:

- Unit 2 is a 175 MWe conventional natural gas-fired steam electric power plant;
- Unit 3 is a 354/365 (summer/winter) MWe unit that was commissioned as a coal-burning thermal power plant in 1958 and subsequently was converted to fire No. 6 fuel oil and/or natural gas in the late 1960's / early 1970's;
- Units 4 and 5 are 361/369 (summer/winter) MWe units originally commissioned as coal-burning thermal power in 1960 and 1961 respectively, but converted to burn No. 6 fuel oil and/or natural gas in the late 1960's / early 1970's.

Plant Design Features

The plant will be refurbished in 2 phases during which two of the steam generators will be repowered using combined-cycle power generation. During Phase I, Unit 2 will be demolished and Unit 5 will be repowered, while the remainder of the plant continues to operate. The repowered Unit 5 will be commissioned and brought on-line prior to the commencement of Phase II, during which Unit 4 will be repowered. At the end of the project Unit 3 will be shut down. This scheduling will allow the facility to minimise the lost generating capacity during the construction phase.

The project will include installation of six Siemens Westinghouse Model 501 FD2 Combustion Turbines, or equivalent. Waste heat from the gas turbine combustion generators will be recovered using six new Heat Recovery Steam Generator (HRSG) units with reuse of the existing Unit 4 and Unit 5 steam turbine generators and auxiliary equipment.

Despite the reduction from four to two generator blocks, the switch to efficient, combined-cycle generators will lead to an increase in generating capacity of 562 MWe over the existing 1,254 MWe output, to 1,816 MWe. The efficiency would be higher than 50%, an increase of at least 15 percentage points. Low sulphur kerosene will be used as the plant back-up fuel. Mandated specifications are for 720 hours or less per year of back-up fuel operation.

Emission Reduction Obtained

Greenhouse intensity per unit energy generated is expected to decrease by 55%. The existing plant emission rate is 826 kg CO_2 / MWhr, which is expected to reduce to 368 kg CO_2 / MWhr after the repowering project is complete. For a 90% available capacity factor, this would equate to a current CO_2 emission of 8,100 kt CO_2 per annum in comparison to a projected emission of 5,300 kt CO_2 per annum for the refurbished plant, an annual abatement of 2,800 kt. The emission savings if the repowered plant was generating at the current greenhouse intensity is 6,500 kt CO_2 per annum.

Other Environmental Benefits

The change to natural gas-fired gas turbine combined-cycle operation will dramatically reduce emissions of both SO_x and NO_x. Selective catalytic reduction will be employed to substantially reduce NO_x.

It is estimated that the introduction of a closed loop condenser cooling system and integrated heat recovery unit will cut water usage to less than 10% of current usage levels.

4.6.2 Financial

Implementation Cost

The repowering project is expected to require a total investment of US$ 1 billion, excluding payroll of the construction force. The construction force payroll is expected to total US$ 128 million, for the entire construction period. The installed cost of the 562 MW of additional power generation is US$ 2,007 / kW or US$ 631 / kW if the plant is considered to be a new installation.

Significant reductions in capital expenditure are expected from reuse of much of the existing plant infrastructure, primarily, the steam turbine and generator sets, existing generator step-up transformers, the surface condenser, and ancillary equipment.

Financing arrangements are yet to be completed and are the final major hurdle to commencement of the project construction phase.

Operating Cost

While actual per unit generating cost is highly confidential, an expected improvement in efficiency of over 30% combined with the switch from fuel oil to natural gas will reduce electrical energy production costs on a per unit basis. A reduction in on-going operational and maintenance costs also can be expected from the reduction in the number of operational boilers and the overall streamlined and modernised plant design.

Abatement Cost

The abatement cost (US$ / t CO_2) has been estimated by calculating an overall annual cost (annualised capital cost - savings in operating cost) and dividing by the annual abatement. The calculations compare the fuel demand and emissions for the repowered plant and a theoretical fuel demand and emissions at the repowered plant's output operating at the old plant's efficiency. The fuel savings exceeds the annualised capital cost and increase in operating and maintenance cost, giving a US$ 18.4 / t CO_2 abatement 'benefit'.

Table 8

	Units	
Reduction in Operating Cost		
Annual Fuel Cost Savings	US $M / yr	286
Reduction in Operating and Maintenance Cost	US $M / yr	-34
Overall	US $M / yr	253
Capital Cost		
Capital Cost of Repowering	US $M	1,128
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	132
CO_2 Abatement Cost		
Overall Annual Cost	US$ M / yr	-120
Annual CO_2 Abatement	kt CO_2	6,526
Cost of Abatement	US$ / t CO_2	-18.4

4.6.3 Key Factors

Enabling Factors

- Projected environmental benefits: reduction in emissions to air and a large reduction in water usage from the East River;
- Recognition of the need for an increase in capacity due to demand;
- Ability to compete more efficiently than existing plants;
- High cost and variability in fuel oil costs.

Careful project planning will enable the current plant to maintain operation during the interim phases of repowering. Staged shutdown dates for the oil-fired units combined with careful scheduling of the start-up dates for repowered units will enable the plant to largely maintain and gradually increase plant output.

Resistances to Implementation

The greatest threat to implementation is the current economic and industry conditions in the United States, the ability of Reliant Energy to secure a long-term purchased power agreement and the strengthening of the company's debt rating and debt restructuring.

Careful project design, detailed planning to ensure environmentally friendly outcomes, and careful explanation of the environmental benefits has helped the project gain the support of local communities and government agencies. There has been no notable resistance.

On June 19, 2003, the New York Siting Board met and approved without dissent Reliant's Article X certificate, which was recognition by the state that the proposed Astoria repowering project design meets environmental rules and is in the public interest. Receipt of the Article X certificate was the last major permitting hurdle for the proposed project; however, no date has been set to commence construction.

Role of Government and Private Enterprise

The project will be carried out by Reliant Energy, a private enterprise company.

The New York State Government has introduced policy to promote development of new efficient generation capacity to maintain pace with demand due to growth. Under this policy, approval for applications for construction and operation of new electric generating facilities over 80 MW can be expedited under the Article X process, as set down in the New York State Public Service Law. Projects that comply with the Article X requirements are issued a "Certificate of Environmental Compatibility and Public Need" which helps streamline the required review under several regulatory programs including environment protection and health laws. As well as the potential for reducing regulatory hurdles, this initiative also serves to include the neighboring community an integral part of the review process and garner community acceptance and support.

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4.7 Chita Thermal Power Station, Fully-Fired Combined-Cycle Repowering

Phase I Basic Category : Repowering
Phase I Emission Reduction Scenario : E12

4.7.1 Project Description

Power Station

Chita Thermal Power Station and Chita Thermal Power Station No. 2, owned by Chubu Electric Power Co Inc., are located near the city of Chita in the Aichi Prefecture on the main Japanese island of Honshu. The first unit of Chita Thermal Power Station started operations in 1966, with the sixth starting in 1978.

All six units of Chita Thermal Power Station are LNG-fired (liquefied natural gas), with the first four units converted to LNG by 1985. Prior to repowering the six units generated 3,350 MW of power by steam generation in the boiler and generating power with steam turbines. Units 1 and 2 are subcritical units, whilst Units 3 to 6 are supercritical.

Units 1 and 2 of the Chita No. 2 Thermal Power Station units commenced commercial operations in 1983, generating 2 x 700 MW of power in supercritical boilers and steam turbine sets.

Plant Modification

To cope with the shortage of electricity supply, Units 1, 2, 5 and 6 of Chita and Units 1 and 2 of Chita No. 2 Thermal Power Stations were repowered to a fully-fired combined-cycle power plant between 1992 and 1996 (summarised in Table 9).

Table 9 : Efficiency Improvement Achieved

Power Station	Chita				Chita No. 2		
	Unit 1	Unit 2	Unit 5	Unit 6	Unit 1	Unit 2	Total
Before Repowering							
Capacity, MW	375	375	700	700	700	700	3,550
Efficiency (HHV), %	30.7	30.7	34.2	35.1	35.0	35.0	34.0
Greenhouse Intensity, kg CO_2 / MWhr	617	617	553	539	541	541	557
After Repowering							
Capacity, MW	529	529	854	854	854	854	4,474
Efficiency (HHV), %	41.6	41.6	40.0	40.1	40.7	40.7	40.7
Greenhouse Intensity, kg CO_2 / MWhr	455	455	473	472	465	465	465
Improvement							
Capacity, MW	154	154	154	154	154	154	924
Efficiency, % Points	10.9	10.9	5.8	5.0	5.7	5.7	6.7
Efficiency, %	36	36	17	14	16	16	20

The design concept of fully-fired combined-cycle repowering is for gas turbines to be added to the existing power plant, with the hot exhaust from the gas turbines fed directly into the existing boilers. The boilers are also fired with fuel to maintain the same steam generation rate, and hence the same rate of power generation from the steam turbines. The power output of the plant is increased by the power generated by the gas turbines. The turbine exhaust gas supplies the required combustion air for the boiler.

For all repowered units, a single 154 MW gas turbine was installed per boiler. For Chita Thermal Power Station Units 5 and 6 and Chita No. 2 Units 1 and 2, Hitachi-GE F7FA gas turbines were installed. For Chita Thermal Power Station Units 1 and 2, Mitsubishi 501F gas turbines were installed.

Consequent Emission Reduction

Repowering of the 6 units resulted in an increase in power output from 3,550 to 4,474 MW (an increase of 26%), and an increase in overall efficiency from 34.0 to 40.7%, an increase of 6.7 percentage points or by 20% in relative terms. There is a small increase in fuel demand (by about 5%). Assuming an 80% available capacity factor, the CO_2 emissions would increase from 13,869 to 14,594 kt CO_2 / annum. However, compared with generating 4,474 MW of power at the old plant efficiency, the repowered plant would reduce CO_2 emissions by 2,885 kt CO_2 / annum.

Greenhouse intensity is reduced from 557 to 465 kg CO_2 / MWhr.

Other Environmental Benefits

Repowering would also result in a reduction in NO_x emission levels.

4.7.2 Financial Cost

Implementation Cost

Data on the implementation costs were not available. However, the purchase cost of each turbine is about US$ 30 million. Assuming the gas turbine cost comprises 50% of the total installation cost, the installation cost for the repowering of the six units is estimated to be US$ 360 million. This equates to an installed cost of US$ 390 / kW for the additional 920 MW of additional power generation.

Abatement Cost

The abatement cost (US$ / t CO_2) has been estimated by calculating an overall annual cost (annualised capital cost - savings in operating cost) and dividing by the annual abatement. The calculations compare the fuel demand and emissions for the repowered plant and a theoretical fuel demand and emissions at the repowered plant's output operating at the old plant's efficiency. The fuel savings exceeds the annualised capital cost and increase in operating and maintenance costs, giving a US$ 33.2 / t CO_2 abatement 'benefit'.

Table 10

	Units	
Reduction in Operating Cost		
Annual Fuel Cost Savings	US $M / yr	156.0
Reduction in Operating and Maintenance Cost	US $M / yr	-18.0
Overall	US $M / yr	138.0
Capital Cost		
Capital Cost of Repowering	US $M	360.0
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	42.3
CO_2 Abatement Cost		
Overall Annual Cost	US$ M / yr	-95.7
Annual CO_2 Abatement	kt CO_2	2,885
Cost of Abatement	US$ / t CO_2	-33.2

4.7.3 Key Factors

Enabling Factors

Chubu Electric Power have had a long-standing policy for increasing their consolidated annual thermal efficiency from their power generation plants and operating in the most economical means possible. For 2001, a gross efficiency of 41.85% was achieved, breaking the record for the seventh consecutive year since 1995, and achieving the highest figure of any power company in Japan for the fifth consecutive year since 1997.

Power demand has increased steadily for Chubu Electric Power (between 1995 and 2000 demand increased by 11%). Repowering has offered an cost effective means of meeting that increased demand, particularly when compared with new power plant costs, whilst also increasing efficiency. The construction time for repowering is also considerably reduced compared with new power plant.

Role of Government and Private Industry

The Electricity Utility Law of Japan regulates the electric power industry in Japan and grants ten privately owned companies an exclusive territory in return for commitment to supply electricity. The law was amended in 1995 to increase the scope of activities for wholesale electricity generators by removing the need to obtain certain approvals and establishing a national bidding system. Given such a regional monopoly, Chubu Electric Power has the requirement of meeting demand with the guarantees of power sales, an important enabling factor for the repowering project.

Japan relies on imports for more than 80% of its energy supply, with a high reliance on oil. Government policy is to achieve energy security through, amongst others, promotion of energy conservation, decreasing the dependence of petroleum and promotion of natural gas development. The concern about the environment also leads to heavy restrictions on land use and this restricts the availability of land for new power generation facilities in Japan. All of these factors makes repowering attractive.

The Japanese Government has made an international commitment to the reduction of greenhouse gas emissions.

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4.8 Senoko Power, Conversion of Gas Turbine Plant from Open-Cycle to Combined-Cycle Operation

Phase I Basic Category : Repowering
Phase I Emission Reduction Scenario : E13

4.8.1 Project Description

Power Station

The Senoko Power Plant, operated by Senoko Power in Singapore, consists of two types of plant. 1,610 MW (or 3 x 120 MW and 5 x 250 MW) is oil-fired thermal plant, and 850 MW (or 2 x 425 MW) is a gas turbine combined-cycle plant. Another 2 x 360 MW gas turbine combined-cycle plant will be coming on stream by March 2005, through repowering of the older oil-fired thermal units.

This case study focuses on the conversion of the gas turbine plant from open-cycle (2 x 262 MW) to combined-cycle (2 x 425 MW) operation.

Plant Modification

The two open-cycle gas turbine blocks, installed for peak load operation, came on line in 1990 and 1991 respectively. In 1996 the two blocks were converted to combined-cycle operation, increasing the total power generation from 524 to 850 MW. The plant was used for base load after its conversion (although operated with an available capacity factor of 55% for 2002 due to oversupply of power generation). At the time of conversion the gas turbine plant met 15.5% of Singapore's total power demand.

The gas turbine plant uses natural gas as its primary fuel, with diesel oil as a standby fuel. Prior to conversion the turbines used fuel oil. Each combined-cycle block consists of two 131 MW Siemens gas turbines, two heat recovery steam generators (HRSGs) and one 163 MW Siemens steam turbo-generator. The net efficiency on a higher heating value basis is 45.9%.

Each HRSG, manufactured by Austrian Energy and Environment, is a vertical, dual-pressure (80 bar at 530°C and 6.5 bar at 200°C), natural circulation drum type, taking gas turbine exhaust gases at 555°C and exhausting to stack at 98°C. The non-reheat, condensing steam turbine is designed for a more efficient two-stage (HP and LP) operation. The Siemens condenser uses sea water as the cooling medium.

The plant was originally designed for fast start-up to support the grid in times of emergency. The whole block can be brought to full load from cold in less than 3 hours, and from hot in less than 1 hour. This feature was retained after the conversion, with a diverter damper located downstream of the gas turbine permitting open-cycle operation.

Consequent Emission Reduction

As a result of the modifications, some 62% additional power could be generated without burning more fuel, with the net efficiency increasing from 28.3% to 45.9% on a higher heating value basis.

There is a reduction in greenhouse gas intensity from 669 to 412 kg CO_2 / MWhr by converting from open-cycle to combined-cycle operating on natural gas. There was also a further improvement as a result of the conversion from oil to natural gas.

In 2002 the plant had an availability factor of 96.5%, but an available capacity factor of just 54.7%. The CO_2 reduction for 2002 is 1,045,000 tonnes, based on the improved efficiency on natural gas for the 850 MW plant.

Other Environmental Benefits

The conversion from fuel oil to natural gas has reduced the level of pollutant emissions. Dust / ash emissions has fallen from 40 to 0 mg/Nm^3. There has also been a large reduction in SO_x emissions. Noise was minimised by use of an acoustic enclosure.

4.8.2 Financial Cost

Implementation Cost

The total cost of the plant upgrade was around US$ 257 million for the four HRSGs, the two steam turbo-generators, the condenser and associated ancillary equipment. The installed cost of the 326 MW of additional power generation was US$ 788 / kW.

Operating Cost

The approximate cost of the natural gas is US$ 28.2 / bbloe (June 2003). Natural gas is sourced from Kerteh in Malaysia by means of a 750 mm diameter pipeline.

Abatement Cost

The increase in power generation revenue exceeds the annualised capital cost together with higher operating and maintenance costs (indicating that this repowering project is economic in its own right), giving a US$ 11.1 / t CO_2 abatement ‘benefit’.

Table 11

	Units	
Change in Operating Cost and Revenue		
Annual Fuel Cost Savings	US $M / yr	0
Annual Power Generation Revenue Increase	US $M / yr	54.6
Reduction in Operating and Maintenance Cost	US $M / yr	-12.9
Overall	US $M / yr	41.8
Capital Cost		
Capital Cost	US $M	257.0
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	30.2
CO_2 Abatement Cost		
Overall Annual Cost	US$ M / yr	-11.6
Annual CO_2 Abatement	kt CO_2	1,045
Cost of Abatement	US$ / t CO_2	-11.1

Project Finance

At the time of the conversion, Senoko Power was under the umbrella of Singapore Power, under the control of the Singapore Government through a statutory board arrangement. Financing was arranged through Singapore Power, which was financially strong.

4.8.3 Key Factors

Enabling Factors

The main enabling factor for implementing the project was the drive for efficiency and the requirement to convert the plant from peak load to base load operation and to increase power generation to meet projected demand.

The second enabling factor was the availability of natural gas from Malaysia, under a 15 year deal that commenced in 1992 (pegging natural gas prices at 7% above the oil price).

Resistance to Implementation

There was no resistance to implementation that could be established.

Role of Government

Energy conservation has been actively promoted by the Singapore Government at the national level through a series of fiscal and non-fiscal policies with the objective of improving overall power system efficiency.

The agreement between the Singapore and Malaysian Governments for the supply of natural gas was an important element in the conversion.

Role of Private Sector

There was very little private sector involvement in the project at that time (prior to restructuring to form a National Electricity Market).

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4.9 Yonghung Supercritical Power Plant

Phase I Basic Category : Repowering
Phase I Emission Reduction Scenario : E14

4.9.1 Project Description

Fuel cost is a significant part of generating costs. Higher fuel prices and the expectation of future increases have led to a need to reduce fuel costs. These economic factors together with a heightened environmental awareness have provided the impetus for the development of plants with improved efficiency. For coal combustion plants, the incorporation of supercritical steam pressure design can significantly improve generator efficiency.

Description of Plant

The Yonghung Plant comprises 2 x 800 MW supercritical coal-fired power plants, and will be the first example of Korea's "standard 800MW class" power plants. The plant is being constructed on the west coast of Korea at the port city of Inchon on the island of Yonghungdo, approximately 50 km west south west of Seoul. The plants are designed for base load and cyclic operation modes and incorporate distributed digital control and a single reheat once-through boiler with a plant efficiency of 43.5% (HHV). Construction is currently underway, with Unit 1 due for completion in July 2004, and Unit 2 due for completion in December 2004.

Table 12 : Plant Design Features

Item	**Specifications**
Power Capacity	800 MWe
Plant Efficiency	43.5%
Vacuum Degree	38 mm HgA
Operation Mode	Base Load Plant with Load Follow Operation Possible
Boiler Type	Supercritical Pressure, Once-through, Single Stage Reheat, Balanced Draft
Fuel	Bituminous coal
Boiler Steam Conditions	254 kg/cm^{2}g, 569 °C
Boiler Efficiency	90.14%
Turbine Type	Tandem compound, HP, IP and LP turbine, Single Stage Reheat, Condensing Type
Turbine Speed	3,600 RPM
Turbine Steam Condition	246 kg/cm^{2}g, 566 °C
Turbine Efficiency	48.26%
Generator	Cylindrical rotor, Hydrogen and Water Cooled, 3 phase Synchronous Generator
Main transformer	3 Phase, 2 Winding Forced Oil to Air (FOA)
Main Control System	Distributed Digital Control (Functional, Hierarchical Distribution)

The once through supercritical pressure steam design allows improved heat rate with variable pressure operation ensuring better performance efficiency than subcritical pressure plants.

Incorporation of an advanced digital distributed process control system including over 18,000 sensors and I/O devices designed by Emerson combined with a boiler design that includes high pressure / low pressure turbine systems helps to streamline operation and reduce start-up time, allowing the system to provide base load supply while enabling cyclic operation. This enables better integration with the rest of the supply system to help deliver generation output that more closely follows the demand cycle. This, in turn, reduces the margin of oversupply required to adequately maintain and manage the supply grid, resulting in better overall grid energy efficiency.

Emission Savings Obtained

At 85% availability annual savings in CO_2 emissions are estimated to be 2,623,000 tonnes, relative to a typical subcritical plant operating at 34 % efficiency (HHV), or an annual saving of 1,219,000 tonnes of CO_2 compared to a modern Korean subcritical plant with an assumed operating efficiency of 38.5%. The greenhouse intensity of the plant is 788 kg CO_2 / MWhr, compared with 890 kg CO_2 / MWhr for a modern subcritical plant.

Other Environmental Benefits

The Yonghung Pant was designed to be environmentally friendly through the use of modern technology to minimise emission of other pollutants and to reduce the overall environmental impact. A two-stage combustion system with low NO_x burners combined with a catalytic reduction system minimises NO_x emissions. The wet limestone process is used to reduce SO_x emissions, with the by-product being sold as commercial gypsum. Emissions of both NO_x and SO_x are designed to be less than 70 ppm, which is almost 65% less than mandatory South Korean standards. Wastewater treatment and reclamation re-use systems are also incorporated in the plant design.

Experience gained with design and implementation of this plant is being used for the design of next generation ultra-supercritical plants, which promise even greater efficiency improvements.

4.9.2 Financial

Implementation Cost

Implementation costs were minimised by production of a detailed feasibility study that looked at all important factors for the proposed plant. These included: Korean grid requirements, availability of local expertise and skills, manufacturers' capabilities in production of steam generators and turbines, competitiveness in the international market and available domestic power plant technologies. Previous experience with technical innovations at a 500 MW plant built in the same region increased confidence at the planning and feasibility stage and provided a sound basis for the project's success. KOPEC learnt from their experience with the planning and construction of the earlier 500 MW plant and, through design improvements, optimal process control and an increased number of competitive bids claim to have identified savings of 293 billion won (US$ 249 million) in construction costs for the new 800 MWe Yonghung Thermal Power Generating Units 1 and 2.

Plant cost is expected to be US$ 2.5 billion at a cost of US$ 1,562 / kW of installed capacity. However, this includes very substantial infrastructure costs, including construction of a bridge to the island and dock loading facilities.

Operating Cost

Efficiency improvements over standard subcritical plants mean improved cost per unit of electrical production. The incorporation of a sophisticated distributed control system means that monitoring of all critical parameters and of plant conditions reduces maintenance costs and staffing requirements.

The incorporation of continuous cycling, 2 shift daily start/stop and 90 minute Fast Start technology mean that supply can be better matched to demand, reducing overall grid costs.

Abatement Cost

The abatement cost has been calculated by comparing the costs and emissions of a new supercritical plant and a new subcritical plant of the same size. The capital cost of a supercritical plant has been taken to be just over 4% higher than that of a subcritical plant. Operating and maintenance costs have been taken to be the same. The coal savings exceeds the annualised capital cost (indicating that it is economic to choose a supercritical plant over a subcritical plant), giving a US$ 11.8 / t CO_2 abatement 'benefit'.

Table 13

	Units	
Reduction in Operating Cost		
Annual Fuel Cost Savings	US $M / yr	27.1
Reduction in Operating and Maintenance Cost	US $M / yr	0
Overall	US $M / yr	27.1
Capital Cost		
Capital Cost Differential (Super vs Sub Critical)	US $M	108.7
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	12.8
CO_2 Abatement Cost		
Overall Annual Cost	US$ M / yr	-14.3
Annual CO_2 Abatement	kt CO_2	1,219
Cost of Abatement	US$ / t CO_2	-11.8

4.9.3 Key Factors

Enabling Factors

With limited indigenous energy sources, South Korea is dependent on imports for almost all its fossil fuel needs. Since 1990 energy consumption has increased rapidly in line with industrialisation. Together with increasing fuel costs, these have provided a strong incentive for efficient utilisation of energy sources.

Local expertise in design and construction developed during construction of earlier supercritical plants including the 2 x 500 MWe and 200 MWe plants have helped. Development of such expertise has been part of a Government targeted technology and engineering skills development programme.

Obstacles to Implementation

Dramatic industrial growth and subsequent projected power demand combined with a state regulated generation industry, meant that there were few obstacles to implementation of the project.

Role of Government and Private Enterprise

The great majority of the generation infrastructure in Korea is owned and operated by the State-owned Korean Electric Power Company (KEPCO) or subsidiary companies that provided financing for the project. The Yonghung plant is now owned by KOSEP (Korean South East Power Company Ltd) a fully owned subsidiary of KEPCO.

The Korean Government has also implemented a number of energy policy initiatives recognising the limited indigenous energy resources and a desire to develop world-class technology in both efficiency and environmental performance. Power plant design and construction, including sales to other countries, has been identified as a national industry goal. The Korean Government has financed research, design and implementation projects to ensure that these goals are met.

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www.kepco.co.kr
www.kosep.co.kr

4.10 Wabash River Coal Gasification Repowering Project

Phase I Basic Category : Repowering
Phase I Emission Reduction Scenario : E17

4.10.1 Project Description

The 262 MWe project is a joint venture of Global Energy Inc and PSI Energy (part of Cinergy Corp.). The joint venture was formed as part of the Department of Energy's (DOE) Clean Coal Technology (CCT) program to demonstrate the repowering of an older thermal generating unit that was impacted by the Clean Air Act Amendments. The project was 50% funded by the DOE during the demonstration period. Construction of the demonstration project was started in 1993, commercial operation started in 1995 and the demonstration period was completed at the end of 1999.

Power Station

Wabash River Generating Station is in West Terre Haute, Indiana. The 1950's vintage power station was comprised of six units, fuelled by pulverised bituminous coal, and used fuel oil for start-up and for flame stabilisation.

Plant Modification

The oldest of the six units (put into service in 1953) was repowered to an integrated coal gasification combined-cycle power plant using Destec's coal gasification technology (known as E-Gas^{TM} Technology). The project retained the 1950's vintage Westinghouse steam turbine generator, some pre-existing coal handling facilities, interconnections and other auxiliaries.

The E-Gas Process is an oxygen blown, continuous slagging, two-stage entrained flow gasifier using locally mined high sulphur coal. The first stage of the gasifier operates at 1,400°C and 27.5 bara. The syngas flows to the second stage where additional coal slurry is injected to increase the syngas heating value and to improve the overall efficiency.

High pressure steam is generated from the hot syngas in a high temperature heat recovery unit (HTHRU). Particulates are separated from the cooled syngas in a hot ceramic filter unit, and returned to the gasifier to maximise carbon conversion.

The syngas is further cooled in a low temperature heat recovery unit (LTHR) and water scrubbed to remove chloride, and passed through a catalyst to convert carbonyl sulphide (COS) to hydrogen sulphide (H_2S). The H_2S is then separated in methyldiethanolamine (MDEA) based absorber / stripper columns.

The syngas is then combusted in the new General Electric 7FA gas turbine to produce 192 MW of electricity. High pressure steam is generated from the gas turbine exhaust gas in the heat recovery steam generator (HRSG). Steam from the HRSG and from the HTHRU is used to drive the Westinghouse turbine, generating 104 MW of power. The net sent out power is 262 MWe.

Commercial operation began in 1995, and quickly demonstrated the ability to operate at capacity and within environmental compliance parameters. However, numerous operating problems resulted in an availability factor of only 22% in the first year. This increased steadily to 70% by the end of 1999.

Consequent Emission Reduction

The project turned a 33% efficient 1950's technology pulverised coal-fired plant (producing 90 MW of power) into a 262 MW (increasing power generation by 290%) gasification unit, operating at 40% efficiency (an increase of 7 percentage points or 21%). There is an associated reduction in greenhouse intensity from an estimated figure of 953 to 786 kg CO_2 / MWhr.

Assuming 70% available capacity factor, the CO_2 emissions would increase from about 526 to 1,262 kt CO_2 / annum. There would be a saving of 268 kt CO_2 / annum if the 262 MWe of power of the repowered plant was generated at the old plant efficiency (33%).

Other Environmental Benefits

The separation of sulphur through this technology dramatically reduces the sulphur emissions (by 98%) using the local Indiana high sulphur coal. The SO_2 emission rate is less than 10% the emission limit set for the year 2000 by the acid rain provisions of the Clean Air Act Amendments. A sulphur by-product is also produced that is 99.999% pure that is sold to sulphur users.

Actual particulate emissions are less than the detectable limit using the EPA approved method.

The slag produced by the process is in vitreous form that has low leaching levels and can be used as aggregate in asphalt roads, thus reducing the need for dumping of ash and emission of heavy metals into the environment.

4.10.2 Financial Cost

Implementation Cost

The actual capital cost of implementing the repowering project was US$ 417 million (1994 dollars). This equates to US$ 1,590 / kW for the 262 MW of installed capacity, and US$ 2,422 / kW for the additional 172 MW of the repowering project. The installed cost for a greenfield site would have been US$ 1,700 / kW, a saving of 7%. It is expected that a new greenfield gasification project, benefiting from the lessons learned at Wabash would have a cost of US$ 1,300 / kW (2000 dollars).

Operating Cost

The technology is economic, with a 12% internal rate of return (IRR), with power prices between US$ 38 and US$ 49 / MWhr for a new greenfield project.

Abatement Cost

The abatement cost (US$ / t CO_2) has been estimated by calculating an overall annual cost (annualised capital cost - savings in operating cost) and dividing by the annual abatement. The calculations compare the fuel demand and emissions for the repowered plant and a theoretical fuel demand and emissions at the refurbished plant's output operating at the old plant's efficiency. In this case the fuel savings are not high enough to cover the annualised capital cost and the higher operating and maintenance costs giving a US$ 249 / t CO_2 abatement cost.

Table 14

	Units	
Reduction in Operating Cost		
Annual Fuel Cost Savings	US $M / yr	3.1
Reduction in Operating and Maintenance Cost	US $M / yr	-20.9
Overall	US $M / yr	-17.8
Capital Cost		
Capital Cost of Repowering	US $M	417
Annualised Capital Cost (20 years @ 10% IRR)	US $M / yr	49.0
CO_2 Abatement Cost		
Overall Annual Cost	US$ M / yr	66.7
Annual CO_2 Abatement	kt CO_2	268
Cost of Abatement	US$ / t CO_2	249

Project Finance

The DOE provided 50% of the total project funding for capital and operating costs during the demonstration period, ending in 2000. The costs totalled US$ 438 million. The remaining 50% was supplied by the other two partners, Global Energy Inc and PSI Energy.

4.10.3 Key Factors

Enabling Factors

The key enabling factor was the DOE's Clean Coal Technology program (which started in 1986), which funded 50% of the capital and operating costs of the project during the demonstration phase.

The program's goal is to demonstrate the best, most innovative technology at a scale large enough to determine whether the processes have commercial merit. Originally the program was a response to concerns over acid rain. The Federal Governments share of the program has been US$ 1.8 billion to date, and has attracted US$ 3.5 billion in private sector funding (or almost two thirds). The Wabash River project was one of 38 first-of-a-kind projects.

Resistance to Implementation

Negotiation of the Co-operative Agreement between the three parties would clearly have been highly complex.

Role of Government

Without the United States Federal Government's participation to help leverage funding, the Wabash Repowering Project and most of the other projects under the CCT banner would never have become a reality. The DOE CCT program greatly assists innovative power generation technology to overcome the barriers associated with construction of demonstration scale projects.

Role of Private Sector

Private industry, through Global Energy Inc and PSI Energy, have played an important entrepreneurial role in developing this technology and providing 50% of the project funding. The reward is a commercially operating first of a kind plant.

4.10.4 References

Paper

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4.11 Map Ta Phut Phase III, Hybrid Co-Generation

Phase I Basic Category : Combined Heat and Power or Co-generation
Phase I Emission Reduction Scenario : E18 / E19

4.11.1 Project Description

The growth of regional centres as a focus for industrial growth can provide excellent conditions for the development of co-generation facilities in line with local industries' needs for both power and heat as steam. Map Ta Phut industrial estate, located in Rayong province, on the eastern seaboard of Thailand, has undergone rapid growth since the early 1990's to become one of Thailand's major industrial centres.

A company was set up in 1993, under the Thai Government Independent Power Producers (IPP) programme, by Banpu Public Company Ltd to be responsible for meeting the electrical energy and process steam needs for industries expected in this high growth area. A number of other companies and developers have also become shareholders in this venture at various times.

The Map Ta Phut generation plants have evolved in 3 phases starting with a gas and oil-fired boiler plant providing 2 x 125 tonnes per hour commissioned in 1994; a gas and oil-fired combined-cycle co-generation plant providing 2 x 150 MWe and 2 x 160 tonnes per hour, completed in 1996; and the new Phase III hybrid gas / coal cogeneration units. After many changes in ownership structure in the intervening years, the Map Ta Phut Phase I, II and III power plants came under the ownership of Glow Company Co, Ltd, which is majority owned by Tractebel. Map Ta Phut Phase III came on-line in March 1999.

For this latest addition to infrastructure for the Map Ta Phut region a number of criteria and operational scenarios were taken into account during the planning process. These included potential variability in coal feed stock and variability of required electrical loads and steam supply demand.

Description of Plant

The Map Ta Phut Phase III includes 2 new Hybrid Combined-Cycle Cogeneration units that have a versatile output configuration and so can produce both high pressure steam and electricity or just electricity depending on demand.

The plant configuration includes:

- Six 35 MW Gas turbines (GT) - GE MS6001B;
- Two 152 MW Steam Turbines Generators (STG) - GE;
- Two Circulating fluidised Bed (CFB) Boilers - Foster Wheeler;
- Four Heat Recovery Units (HRU) - Foster Wheeler.

The Hybrid Cogeneration units integrate a circulating fluidised bed coal-fired plant with a gas-/oil-fired plant using a common heat recovery unit. This design allows Map Ta Phut the versatility to supply large quantities of high pressure steam for industrial processes while providing efficient electricity generation. The plant output is rated at 514 MWe and 2 x 100 tonnes per hour process steam. The boilers have been designed for operation with feedwater temperatures ranging from 150 °C to 275 °C, depending on whether feed water heating is available from the gas turbine HRUs due to steam output demand.

The Hybrid design enables high efficiency production of electricity and high pressure steam while reducing capital costs that would otherwise be associated with construction of separate coal- and gas-fired plants. Capital costs are reduced by eliminating the need for a heat recovery steam generator, separate feed water train and reheater of conventional designs and replacing it with a simpler and cheaper heat recovery unit (HRU), which efficiently transfers heat from the gas side to the coal side of the plant.

By use of the hybrid concept, the feed water train and the boiler reheater of the Rankine steam cycle as well as the heat recovery steam generator of the combined-cycle are replaced by a simple gas to water/steam heat exchanger, the HRU. The HRU is not used to boil water but simply as a three-section heat transfer unit, one section for each cycle component being the steam reheater, feedwater economiser and condensate economiser. In each section of the HRU, heat transfer takes place at very small temperature differences between the gas turbine exhaust gas and the water/steam side. This reduces thermodynamic losses that would occur by using a combined-cycle gas turbine and a separate coal plant operated in condensing mode. The HRUs receive exhaust gas from the gas turbine at 553 °C and cool it down to 100 °C. The steam outlet reheat temperature from the units is up to 530 °C. Modelling has shown an increase in efficiency from 40.7% to 43.0% for the Map Ta Phut hybrid compared to separate similar plants.

Additionally, a single large and efficient steam turbine generator effectively replaces the 2 separate turbines that would be required for conventional separate plants.

The coal-fired plant incorporates a circulating fluidised bed (CFB) design that allows the plant to efficiently handle a high degree of variability in the quality of available fuel feedstocks. This allows the operator to take advantage of fluctuations in price and availability of different fuels while maintaining efficient generating capacity. At the same time the CFB design of the coal-fired boiler significantly reduces emissions of SO_x and NO_x compared to conventional pulverised coal plant.

Plant Design Features

Hybrid (coal- and gas-/oil-) fired co-generation plant reduces capital cost and allows flexibility of fuel mix. At a gas to coal price ratio of 2:1, the hybrid design has a cost advantage of 9% relative to separate units in fuel costs alone. The simplified design when compared to 2 separate plants should also mean additional ongoing operational and maintenance cost savings, including reduced staffing requirements.

The CFB coal-fired plant allows versatility of fuel selection enabling the plant to use a variety of different fuel qualities depending on availability and cost, whilst still meeting the high environmental standards specified.

Overall efficiency for the Hybrid plant is improved to 43.0% (HHV) as compared to 40.7% (HHV) for separate combined-cycle gas turbine and coal-fired boiler plants.

Emission Reduction Obtained

Emission intensity is expected to be 796 kg CO_2 / MWhr. This does not take into account the useful energy in the form of steam gained from the co-generation technology. Based on generation efficiency improvements, the Map Ta Phut Hybrid development offers an estimated reduction in CO_2 emission of 183,000 t per annum in comparison to separate combined-cycle gas turbine and coal-fired boiler plants.

Other Environmental Benefits

Emission reduction mechanisms for the CFB coal plant reduce SO_x and NO_x, whilst the hybrid design means overall greatly improved environmental performance for SO_x, NO_x, and particulate emissions than for separate conventional plants.

4.11.2 Financial

Implementation Cost

Simplified design including replacement of separate turbines for gas and coal boilers, replacement of a HRSG and conventional feed-water train and reheater with a simpler more efficient HRU means a substantial reduction in construction and equipment costs for the Hybrid design over separate coal and gas units. The capital cost for the Hybrid plant construction and equipment is US$ 544 million and is estimated to be 12% lower than for conventionally designed plants. The installed cost for the 514 MW of power is US$ 1,058 / kW.

Operating Cost

The simplified design when compared to 2 separate plants should also mean additional on-going operational and maintenance cost savings, including reduced staffing requirements.

Financing

The project was financed using a “Build, Own Operate” model by Cogeneration Company Co Ltd set up by Banpu Public Company Ltd with major shareholders including Sithe Industries, under the Government Independent Power Producers and Small Power Producers programmes.

4.11.3 Key Factors

Enabling Factors

The close relationship between client industries in the Map Ta Phut industrial area and the infrastructure provider enables excellent understanding of the regional industry needs. Long-term contracts were pre-signed for supply from the new plant with industries in the development region.

The Thai Board of Investment provided a raft of incentives to enable the project to commence including reduction of import duties, short term exemption from corporate income tax, tax deductions for utilities and transport usage, deduction of the costs of installation and construction of the project's infrastructure facilities from net profits, and exemption from personal income tax for dividends to shareholders.

Obstacles to Implementation

A major obstacle to the project was lack of local engineering and design skills. This was overcome by allowing a build-own-operate model for the project. This allowed purchase and licensing of skills and technology appropriate to the project that weren't available locally, and full cost recovery to be spread over a longer term.

In the early stage of operation there was potential for significant excess of supply above requirements for the local industrial estate. The state-owned Energy Generating Authority of Thailand (EGAT) agreed to buy surplus supply. Additionally, EGAT also agreed to provide back-up electricity, should this be needed, which effectively guaranteed project reliability.

Low community and industry awareness of environmental performance and generator efficiency can be an obstacle in developing countries. Cogeneration Company Ltd and the Government embraced the possibilities of improved performance efficiency, reduced capital cost and better environmental performance. The earlier success of the staged implementation of the Phase I and Phase 2 Map Ta Phut power plants together with the experience of its part-owner Nordic Power Invest gave the infrastructure operator, CoCo, the confidence to implement the innovative Hybrid technology. While the proposed Hybrid design was new and innovative, it was carefully designed to meet the need of the local industrial region as well as the availability of fuel. Its potential efficiency improvements, capital cost reduction, operational cost advantages, environmental improvements and careful design feature outweighed the potential technology risks.

Role of Government and Private Enterprise

Government policy on developing efficient industries and the move to a competitive energy market has provided direction for the establishment of efficient technological solutions in the power industry. The Thai Government has also set a target for annual reductions of greenhouse gas emissions.

The central Government has targeted for economic growth through development of efficient industries, which has been rewarded with rapid industrial growth through the 1990s. Its Public Enterprise Development Policy encourages private sector involvement through joint developments and also by enabling the private sector to take a stake in government-owned public companies as they are listed on the Stock Exchange of Thailand. Through the government owned Electricity Generating Authority of Thailand, the Thai Government is implementing its vision for a competitive energy market for the nation and also a future as part of the proposed Association of South-East Asian Nations (ASEAN) Grid.

4.11.4 References

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4.12 Glossary

AGO	Australian Greenhouse Office
APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of South-East Asian Nations
bbloe	Barrels of Oil Equivalent
BOT	Build Own Transfer
BPS	Bayswater Power Station (Australia)
CCT	Clean Coal Technology
CFB	Circulating Fluid Bed
CO_2	Carbon Dioxide
COAG	Council of Australian Governments
COS	Carbonyl Sulphide
DOE	Department of Energy (United States)
DPIE	Department of Primary Industry and Energy (Australia)
ECA	Energy Conversion Agreement
EGAT	Energy Generating Authority of Thailand
GGAP	Greenhouse Gas Abatement Program
GT	Gas Turbine
HHV	Higher Heating Value
H_2S	Hydrogen Sulphide
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HRU	Heat Recovery Unit
HTHRU	High Temperature Heat Recovery Unit
IP	Intermediate Pressure
IPP	Independent Power Producer
IRR	Internal Rate of Return
KEPCO	Korea Electric Power Corp.
KEPRI	Korea Electric Power Research Institute
LNG	Liquefied Natural Gas
LP	Low Pressure
LPS	Liddell Power Station (Australia)
LTHR	Low Temperature Heat Recovery Unit
MDEA	Methyldiethanolamine
MRET	Mandatory Renewable Energy Target
MW	Mega Watt
MWe	Mega Watt Electrical
MWhr	Mega Watt Hour
NAPOCOR	National Power Corporation (Philippines)
NEM	National Electricity Market (Australia)
NO_x	Oxides of Nitrogen
ORER	The Office of the Renewable Energy Regulator
PPI	Pacific Power International
SO_x	Oxides of Sulphur
SPC	State Power Company
STG	Steam Turbine Generators
TILF	Trade and Investment Liberalisation and Facilitation
TSP	Total Suspended Solids
UNFCCC	United Nations Framework Convention on Climate Change
ZPEPC	Zhejiang Provincial Electric Power Company (China)

5. ENABLING FACTORS FOR THE REDUCTION OF CO_2 EMISSIONS

There is a whole range of factors that contribute to effective reduction in the release of carbon dioxide. Governments, industry and the financial sector all play a part in an efficient overall strategy. This section considers every major factor, describing its influence and the range of possible actions that can be taken to improve abatement.

APEC represents a very broad range of economies concerned with greenhouse matters. Membership ranges from economies actively developing appropriate greenhouse abatement technologies on a large scale, such as the United States and Japan. Other members have energy resources to share with neighbouring economies while many see abatement as a product of improving the efficiency of their economy.

5.1 Government Attitude

Governments exert control, either directly or indirectly by way of regulation, on the energy resource mix used to generate electricity in their economy. This energy mix is the key both to efficient supply of power to the population and to potential greenhouse abatement.

While greenhouse gas abatement is acknowledged to be internationally important, governments in many economies, including many in the APEC region, have many other critical issues that they have to confront both domestically and internationally. Any study must take these important factors into consideration when focusing on the greenhouse issue.

Those economies with a higher standard of living can more easily afford to take actions complementary to greenhouse abatement and generally do so. However economies that have more pressing needs such as the health of their population cannot allocate greenhouse reduction the same level of attention.

In general, government actions reflect this situation well. Government attitude may be an enabling factor or a barrier in greenhouse abatement.

5.1.1 Indigenous Energy Resources

Most governments have policies promoting the utilisation of their indigenous energy resources. These resources may or may not have a greenhouse implication. The use of indigenous resources has many positive benefits for the economy including employment and domestic income.

Economies with energy resources excess to their needs may also have policies promoting the export of energy resources to their neighbours that do not have adequate resources. Few governments promote or can be expected to promote policies that go against these basic facts. In the future there may be some incentive for governments to consider such matters.

5.1.2 Domestic Issues

With respect to energy supply all economies need to ensure adequate power supply to maintain the standard of living for the population. Fossil fired power stations emissions to air / water are / should be regulated for health reasons and hydro projects require policies on resettling and compensation for those displaced during the development of large dam installations.

5.1.3 International Issues

Greenhouse abatement is the subject of international agreements. Many economies are concerned, some have signed on to international agreements, such as the United Nations Framework Convention on Climate Change and the Kyoto Protocol while others are actively reducing greenhouse gas in their own manner. Some economies have not been able to consider international actions because of their domestic needs.

5.2 Carbon Penalties

One of the outcomes of concern for the effects of greenhouse is the imposition of policy instruments designed to limit the use of fossil fuels. One approach is the implementation of a direct carbon content tax as has been initiated in Norway. The proceeds of this tax may be used to minimise greenhouse or to add to consolidated revenue in the economy in question.

An alternative approach is the introduction of some form of emission trading. This has been instituted in some economies but really needs to be international in nature to be effective. This has the potential to minimise the actual cost of reducing greenhouse gas release in the most economic way.

There are a number of possible mechanisms for imposing carbon penalties, with different levels of associated risk and different possible dates for introduction. This provides the energy investor, whether government or entrepreneur, with a high level of unquantified risk and uncertainty. As a result investment in new plant is delayed.

High carbon penalties are a significant barrier to installing advanced coal-fired plant with reduced greenhouse generation capability or any other carbon utilising plant. A more balanced level of penalty will promote the use of advanced coal-fired plant over conventional installations. In this scenario the level of carbon penalty imposed would vary from economy to economy, and optimised to take account of national circumstance and the government's long-term energy mix strategy.

5.2.1 Industry Initiatives

New power generation plant has a life of about 50 years. Both government, in the case of public sector monopolies, and industry in the case of a competitive market have to make very large commitments to fund new plant. As part of this they must allow for a much greater level of risk than would be necessary if the carbon penalty regime were known and could be included in the financial analysis for each project.

As a consequence, the cost of new plant is greater than otherwise would be required.

5.2.2 Government Initiatives

Some governments have instituted voluntary emission trading regimes. For instance, the Australian Government, through the Australian Greenhouse Office, has set up the Greenhouse Challenge program. This program allows industry to commit to fulfilling greenhouse guarantees over a period. This program has resulted in significant voluntary abatement over a number of years.

Others have instituted limited legal trading regimes. An example of this is the New South Wales Government in Australia, which has legislated for its own Greenhouse Gas Abatement Scheme for generation within the State of New South Wales. This effectively sets a cap for the greenhouse gas release and progressively reduces this value.

It requires large electricity customers and retailers to identify their greenhouse gas release and purchase carbon free generation or pay a per-tonne of emission levy for their excess. This is designed to not interfere with the operation of the competitive market but constitutes a disincentive for new facilities or additions to be made in this state because of the added non-competitive cost of energy supply.

These are examples of types of initiative awaiting international recognition of a universal process. Agreement on such a system will reduce uncertainty and perceived risk for decisions on committing to new generation plant.

5.2.3 Carbon Penalty Uncertainty

The imposition of a carbon penalty is a serious challenge to investment in new plant but the additional uncertainty over the likely type, intensity and timing of carbon penalties imposed by government presents a major barrier to new plant commitments and must be addressed.

5.3 Development of Clean Coal Technology (CCT)

The active development of advanced clean coal technologies is a major enabling factor in mitigating greenhouse gas release. Clean coal technology covers an extremely broad range of activities by industry and government. It has the dual advantage of improving plant efficiency and greenhouse abatement.

All clean coal technologies are more capital intensive than conventional plant. In some cases the additional capital cost is more than recouped by improved performance. Supercritical pulverised coal plant is in this category. With some of the more advanced technologies this stage has not yet been achieved. Gasification technologies are in this group. Their superiority, with respect to carbon dioxide collection for sequestration, will become a valuable additional incentive when carbon penalties are invoked.

While the components of the technology are generally known there are new and novel applications and combinations of equipment that have not been used before. The risks associated with the components are fairly well defined but the risks associated with operating them in a particular manner are not.

5.3.1 Industry Initiatives

Power generation plant has been developed and supplied by a small number of competitive organisations for many years. The cost of development has largely been provided by the industry with some government assistance. The cost of extending present technology or developing radical new technology has risen rapidly with the level of sophistication.

Significant advances have been made by industry. These have tended to be incremental rather than revolutionary in nature. An example of this is the gradual increase in steam pressure and temperature in modern supercritical coal-fired generators. The increases have awaited the development of alloys that can operate continuously at elevated conditions for many years to be economic.

The increase in steam temperature and pressure has improved the efficiency of new coal-, oil- and gas-fired plant and consequently lowered the level of greenhouse gas release and, incidentally, reduced the efficiency advantage of advanced CCTs that have greenhouse benefits, like coal gasification.

5.3.2 Financial Organisation Initiatives

Both the World Bank and the Asian Development Bank have programs supporting various aspects of CCT. The World Bank has interests in coal washing, coal briquetting, and in rehabilitating older power stations. It is also assisting with advanced CCT assessment and with policy advice. For instance the Asian Development Bank has funded a review of the washability of Indian coals.

5.3.3 Government Initiatives

Governments have taken the initiative in seed funding major advances in generation technologies that were beyond the financial capability of equipment suppliers. With respect to coal the United States has, through the Department of Energy, called for competitive offers to share in the development of new, more efficient technologies.

This resulted in the now famous Clean Coal Technology initiative. This was started in about 1992, produced new technologies operating in the late 1990s, and now plants operating with high availabilities and operating in competitive electricity markets.

There are excellent examples of these in the Wabash plant that converted a stranded asset (a 100 MW conventional coal-fired unit) that could not compete in the market into a highly competitive 250 MW integrated gasification combined-cycle (IGCC) unit. The Polk Power Station is an example of a new facility IGCC of 250 MW capacity. Both of these are efficient, high availability units.

The United States Government has added to this initiative recently by committing to the FutureGen initiative. This is a consortium of nine large utilities in an alliance with the Government seeking the creation of a near zero-emission power plant and hydrogen production facility with integrated carbon dioxide management. It will be a test bed for new coal-based power generation technologies capable of producing electricity and hydrogen with near zero emissions over the next ten years.

On a smaller scale, the Australian Cooperative Research Centre (CRC) concept for bringing academia and industry together with common goals has been very successful. A number of CRCs have been focused on energy resources and have carried out valuable work to complement the major U.S. initiatives.

Major economies, such as China and India, have committed to build further clean coal technology facilities to utilise their indigenous energy resources, maximise plant efficiency and thus reduce greenhouse gas release.

5.3.4 Limited Competition

One of the issues with such programs is the resulting effective technologies are controlled by a few organisations keen to seek returns on their large investments. This has resulted in relatively few offers for new plant of an advanced specification. The control of technology and intellectual property for the supply of large new power stations is now in the hands of a few large organisations.

5.4 Communication and Technology Transfer

Making industry and government aware of the potential for CCT is a critical enabling factor for its development. While major investment in new technology development can only be carried out by large economies such as the United States, there is a role for smaller economies to communicate the results of this work and manage technology transfer to a range of other economies that can benefit from the advances.

This task falls into two distinct categories. The first is communicating the results at a number of different technological levels to match the technological awareness of those in decision making positions. The second category lies in transferring appropriate technology, in a controlled manner, once decisions are made on committing to new technology.

5.4.1 Communication of Technology Information

A number of economies have undertaken the task of communicating the results of major projects into information at levels appropriate to bureaucrats and entrepreneurs with different technological awareness. The United States runs its own communication service on clean coal technology via the Clean Coal Initiative.

Within APEC, the Expert Group on Clean Fossil Energy runs regular conferences and workshops and provides effective publications on many aspects of clean coal technology including this document.

Within Europe, the IEA Clean Coal Centre in London provides an excellent resource on-line. Canada and Australia both have web facilities and Australia has recently sent a group of government and industry representatives to the United States to result in a team aware of the potential for clean coal technology.

5.4.2 Technology Transfer

APEC has taken a lead in technology transfer in running a series of workshops on various aspects of clean coal technology in a number of APEC economies. These have been well attended, with many speakers having been provided from other APEC economies. Further necessary technology transfer would obviously occur with specific installations.

5.5 Implementation of Clean Coal Technology

After the development stage, the implementation of CCT is a major enabling factor. The United States has done an excellent job in developing demonstration new technology plants such as Wabash. At the same time Japan has done a similar excellent job in demonstration of ultra-supercritical units. These initiatives have made available large commercial units of the different technologies for economies that do not have the required resources needed to develop them.

Implementation can be by direction in a monopoly situation or as the project with the most long-term potential in a competitive market situation taking into account capital costs and likelihood of carbon penalties.

5.5.1 Capital Cost of Plant

Particularly with the competitive electricity market the capital cost of new technology plant is an important barrier to greenhouse abatement. Incremental improvements in conventional plant to move from subcritical to supercritical to ultra-supercritical have been made over a number of years. Generally speaking, costs have been constrained so that the more advanced units are not significantly more expensive than earlier versions.

New technology units of the IGCC or PFBC technology are significantly more expensive because of their advanced technology and few units having been commissioned. The capital cost of these units will come down as more units are installed and some level of standardisation can take place. Present units are virtually one off with consequent allocation of a high proportion of costs to one project. Standardisation of design could allow spreading costs over a number of units with corresponding possibility of cost reduction.

Depending on the technology, considerable enhancements are possible to offset any additional costs. Probably the most effective of these is poly-generation, (see section 5.5.5 below), where the plant is designed to operate with its availability similar to that of an oil refinery.

5.5.2 Time to Initial Generation

A competitive electricity market requires small additional generation capacity to be added to the system at regular intervals. CCT can provide this regime effectively. Present time to bring a new unit to a commercial solution is far too long compared with gas turbine plant, however there are simple means of reducing this to an acceptable minimum. A considerable proportion of this lies with necessary government processes.

5.5.3 First of a Kind Plant

First of a kind plant presents special additional risks. In general the components have been tested separately and are insurable in the normal manner. However, the combination of plant and its level of integration provide a risk that is very difficult to insure because of its novel nature.

The Japanese Government has been very effective in supporting this type of plant. Through the Ministry of Economy, Trade and Industry (METI) it has provided funding so that conventional power companies can build new technology plants. An excellent example of this is the Karita Power station of Kyusuu Electric. This is a pressurised fluidised bed combustion (PFBC) power station with a capacity of 300 MW. This policy is also supporting IGCC with two plants on the drawing board for commissioning before 2010.

5.5.4 Subsequent Installations

Until new technology installations have a record of adequate availability there will be a need for some form of assistance or insurance to cover operating teething problems. The form of this assistance needs further consideration.

5.5.5 Poly-Generation

Cogeneration is the production of electricity plus heat as a by product. Poly-generation is the production of a number of products from the same plant. One of these is electricity but the others may be heat, steam, hydrogen or a range of chemicals and fertilisers.

Normal power station plant is limited by its capacity factor, the proportion of time that the unit is operating in the system. In a well run system, this may be as high as 80% but is often much lower. The ability to produce an adjustable quantity of a number of products allows the capacity factor of the plant to rise to close to oil refineries and other almost continuously operating plant. This means that the investment is much more effective than for a conventional power station.

5.5.6 Government Initiatives

From the above it can be seen that government action, generally in conjunction with industry and the financial sector has resulted in the development of suitable new technology demonstration plants. Government has also been willing to fund a considerable part of first-of-a-kind plants. This has been limited to those APEC economies that are in a position to invest large sums in bridging the technology gap. Other economies are not in a position to do this. They probably fall into the group that will eventually utilise the new technologies developed in the United States and Japan.

5.6 Transition to a Competitive Energy Market

Another critical enabling factor in the reduction of carbon dioxide is the transition towards a competitive electricity market in many APEC economies. Monopoly conditions existed in the power industry for many years. Governments owned or franchised power supply, and accepted all the risk.

More recently governments have allowed to private sector to assist in providing energy infrastructure, freeing up government income for other more vote sensitive issues and maintaining control via regulation of the industry.

A competitive market generally operates at higher efficiencies than a monopoly situation, with resulting improved greenhouse abatement. Entrepreneurs are also more likely to utilise technologies such as poly-generation than conservative government controlled power organisations.

5.6.1 Monopoly Conditions

Under monopoly conditions governments ran the power system or franchised the running of it by a commercial organisation. They controlled the resource energy mix and therefore the level of greenhouse abatement as part of the overall energy scene. This made it relatively easy to mandate new technology installations. The risks in new technology were covered by government.

5.6.2 Competitive Conditions

Competitive market conditions provide the entrepreneur with a challenge to craft a possible new generation facility to make an adequate return while obeying all the regulation requirements.

Governments can still retain some control over resource energy mix by setting suitable incentives. They should, of course, not attempt to manage the market and greenhouse abatement with the one regulation. The market should be left to compete and different means used to initiate greenhouse abatement. In this way both goals can be attained effectively.

5.7 Application to APEC Economies

APEC economies cover an extremely broad range of political situations. This means that the approach to abating greenhouse gas will be quite different. Different economies have a different position with respect to the factors set out above.

5.7.1 Viet Nam

Separately in this document the long-term energy planning for Viet Nam is discussed. EVN is government-owned entity so that the government can control the type and extent of new generation installed. It has indigenous anthracite resources that could be used in advanced technology plants to make electricity with low greenhouse gas release.

5.7.2 Malaysia

Malaysia is a rapidly growing economy in transition to a competitive market. It still retains some control over energy resource mix. It is installing new coal-fired power stations to help stabilise the power system in the event of loss of gas supply to a system that is highly dependent on gas.

5.8 References

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5.9 Glossary

APEC	Asia-Pacific Economic Cooperation
CCT	Clean Coal Technology
CRC	Cooperative Research Centre (Australia)
IEA	International Energy Agency
IGCC	Integrated Gasification Combined-Cycle
METI	Ministry of Economy, Trade and Industry (Japan)
PFBC	Pressurised Fluidised Bed Combustion

6. SELECTION OF TARGETED ECONOMIES

An important element of this particular phase of this project (Phase II) is to review the approach taken by two developing APEC economies to reduce CO_2 emissions. The objective is to highlight action plans that are being successfully implemented to illustrate possibilities for all APEC economies. This Chapter describes how the target economies were selected, and the economy reviews are given in the proceeding two Chapters.

From the list of APEC economies those that are defined as in the developing class include China, Indonesia, Malaysia, Philippines, PNG, and Viet Nam. Others may also be developing but the definition is not rigid.

The criteria that were used for selection of the target developing economies were as follows :

- Target developing economies should have high CO_2 reduction potential in the short to medium term;
- Target economies should illustrate the potential to reduce CO_2 in the majority of APEC economies;
- Adequate data should be available on installed generating plant. There should be future planning proposals that can be used as a reference to show improvement against original "business as usual" plan;
- Economies selected should have significantly different action plans to highlight possible approaches;
- Economies selected should illustrate different technologies to show different possibilities;
- Economies selected should illustrate different market conditions for power supply (ie monopoly, market driven or transition to market driven).

Suitable target developing economies that meet these criteria (there may be additional economies) are :

- China is in transition to market economy for power generation. It depends strongly on coal and so has a high potential for CO_2 reduction. Availability of reliable data is questionable. It has a forward plan for new plant. However, it is such a large and diverse economy that it would be difficult to cover satisfactorily;

- Indonesia is a near-monopoly for power generation. It depends on coal and oil and has a medium potential for CO_2 reduction. Availability of reliable data is questionable. There are a few major plants and these tend to be international IPPs. It has a forward plan for new plant, which would give a good basis for comparison with "business as usual";

- Malaysia is in transition to market economy for power generation. It depends on gas and is installing coal for security so has a high potential especially with respect to new advanced coal technology plant. It has future generation plans;

- The Philippines is in transition to market economy for power generation. It depends on oil and gas. It has significant older plant that could benefit from refurbishing or repowering. Data is probably easy to obtain. It has a future generation plan;

- PNG is a monopoly. It has a very small power system and is atypical. It should not be considered further;

- Viet Nam is a monopoly market for power generation, so new plant can be directed by government. It has adequate generation capacity and stated future generation plans.

The two economies that best fit the selection criteria were considered to be Viet Nam (a largely centrally planned or monopoly market) and Malaysia (an economy whose power generation is market driven, or at least in the transition to market). This would give an indication of how the different market systems affect the way that action plans might develop.

7. TARGETED ECONOMY REVIEW - MALAYSIA

7.1 Economy Summary

Malaysia has enjoyed stable government and generally strong positive economic growth over the past 3 decades, which has ensured its position as one of the wealthier economies in the South-East Asian region. An economic downturn was experienced during the financial crisis of 1997 - 1998 which interrupted otherwise strong economic growth. There was a recovery in 1999 and 2000 with real gross domestic product (GDP) growth above 6%. Since then growth has slowed due to the global downturn, with a GDP growth rate improving from 0.43% in 2001 to 4.1% in 2002. Following significant depreciation after the 1997 regional financial crisis, the local currency, the ringgit, was pegged at an exchange rate of RM 3.80 per US$ in 1998. The Malaysian economy has a continued outlook for high growth and is supported by good fundamentals including a strong current account surplus, a growing manufacturing sector, low inflation and significant foreign reserves.

Strong economic, industrial and manufacturing growth, and heightened environmental awareness have been major drivers behind Malaysia’s policies to ensure future energy security and sustainability. Malaysia has been a strong supporter of international environmental conventions including the UNFCCC and Kyoto Protocol and other international initiatives on climate change and energy management. Malaysia has taken a “no regrets” approach to greenhouse abatement. Any greenhouse gas abatement strategies would be expected to be complementary to the comprehensive range of policies, initiatives and incentives in place to address issues of energy sustainability and supply security in a growing economy.

Malaysia has significant fuel reserves particularly in natural gas but, with major industrial growth increasing energy demand, has been quick to recognise the need for careful management of its energy resources. Apart from fossil fuel reserves of gas, oil, and coal, significant use has been made of Malaysia’s hydro energy resources and there is significant potential for development of other renewables such as biomass, solar, and wind projects.

Whilst the majority of existing generation capacity is fuelled by natural gas, the focus for most planned additional capacity until 2010 is coal-fired plants, based on Clean Coal Technology. The policy decision to implement more thermal coal generation in preference to natural gas has been made to diversify energy mix for power generation. Some existing open-cycle gas turbine plants will also be upgraded and a number of new gas turbine plants are planned. This will be supplemented by renewable energy, including a major hydro project in Sarawak, biomass (principally utilisation of palm oil industry waste) and others.

Demand side measures including industrial, commercial and domestic energy efficiency programmes will also help mitigation of greenhouse emission intensity. Significant investments in improvements to the transmission and distribution systems are also planned to 2010, which should help reduce system losses, and will prove another factor in reducing future greenhouse gas emissions.

7.2 Economy Description

7.2.1 General

Population Demographic

In 2002, the population of Malaysia was approximately 24.5 million with an annual average population growth rate of between 2.1% and 2.3% since 1997. Average life expectancy is 72.7 years. Approximately 62% of the population live in urban settings and 38% rural, with urban population growth being significantly greater than the national average.

Geography

Malaysia consists of the Malay Peninsular, the island of East Malaysia, Sarawak and Sabah, and coastal islands. With an approximate area of 329,750 sq. km, Malaysia has 4,675 km of coastline. Approximately 23% of the total land area is cultivable. Malaysia has many contrasts in topography with both mountainous and water-rich regions that have provided ample scope for the implementation of hydroelectric projects.

Industry

In order to appreciate the challenges facing Malaysia in greenhouse mitigation, it is important to understand the national goal of attaining developed nation status and the rapid industrialisation that has ensued.

There has been a significant increase in industrial growth over the past decade with this sector representing 49.6% of GDP by July 2001 as opposed to 42.1% in July 1991. Manufacturing alone accounted for 30.1% of GDP as of July 2001. As with other sectors of the economy, manufacturing was hit hard by the world economic downturn of 2000, but is recovering with strong economic growth expected over the next few years.

Major products and industries include tin, rubber, palm oil, timber, oil, textiles and electronics. Malaysia's major trading partners include Singapore, Japan and the United States of America. Malaysia seeks to move to a technology, services and knowledge-based economy. Government policy has included the promotion of high technology manufacturing and technology services for export growth. The realisation of Malaysia's high-technology exports growth and the Multimedia Super Corridor initiative are examples of these policies.

Sectoral Economic Data

Table 15 : Sectoral Size

Economic Indicator (as % of GDP)	**1981**	**1991**	**2000**	**2001**
Agriculture	21.4	14.4	8.6	8.4
Industry (Manufacturing)	40.3 (20.9)	42.1 (25.6)	51.7 (34.3)	49.6 (32.1)
Services	38.3	43.5	39.7	41.9

Source : WDB, ADB, EC, BNM

Table 16 : Sectoral Annual Growth (end of 2001)

Indicator	Growth
Real GDP growth for 2001 (actual)	0.4%
Real GDP growth for 2002 (estimated)	4.1%
Agriculture	-0.9%
Mining	-0.8%
Manufacturing	-5.8%
Construction	2.1%
Services	5.7%

Source : BNM

Socio Economic Information

The Malaysian economy has continued to improve following the economic decline in the Asian region in the late 1990's. The annual growth rate as a percentage of Real GDP returned to 0.43% in 2001 and grew to 4.1% in 2002.

For the year 2001, GDP was US$ 87.5 billion, with per capita income of US$ 3,664. The electricity demand per capita was 2,625 kWhr.

Political Geography

Malaysia is a parliamentary democracy with a constitutional monarchy of 13 Federated States and three Federal Territories. Nine states have royalty rulers as heads of state and the remaining four States are headed by elected Governors.

In regard to power supply the major regions are Peninsular Malaysia, Sabah and Sarawak each with separate grid systems. The major power producer and distributor in Malaysia is Tenaga Nasional Berhad (TNB), which operates in Peninsular Malaysia, with vertically integrated government monopolies dominant in Sarawak and Sabah. There are also several Independent Power Producers (IPPs).

TNB was established in 1990 as the result of the Malaysian Government's corporatisation and subsequent privatisation of the National Electricity Board (NEB). In 1992 it became a private listed company after a public offering of shares on the Kuala Lumpur Stock Exchange. It is one of the largest listed companies in Malaysia.

TNB controls the major generation subsidiaries in both coal- and gas-fired thermal generation plants as well as major hydro assets through TNB Hidro (TNBH).

On Peninsular Malaysia, TNB's thermal power plant consists of conventional oil- and coal-fired steam power plants and combined-cycle gas power plants with a total installed capacity in 2002 of 6,144 MW. TNBH manages the operations and maintenance of three groups of hydro plants in Peninsular Malaysia including generators, turbines, pumps, dams, spillways, gates, waterways, and catchment areas with a total installed capacity of 1,911 MW.

TNB will remain a dominant player in the growth of new capacity with current project developments including the Manjung Power Plant in Perak Darul Ridzuan, managed through its subsidiary TNB Janamanjung (TNBJ). The Manjung development is a pulverised coal-fired 3 x 700 MW power plant with an estimated capital cost of RM 7 billion (US$ 1.84 billion). The first 700 MW unit for Manjung was placed on commercial operation on 21 April 2003. When completed this project will provide Malaysia with significant new generation capacity.

7.2.2 Energy

Malaysia has significant fossil fuel and hydro resources that have been successfully developed and utilised to meet electrical generation demand. Nonetheless there is a strong appreciation of the finite nature of fossil fuel resources and the importance of careful strategic planning to maintain sufficient generation capacity growth for continued economic development, whilst managing finite fossil fuel resources to ensure a sustainable energy future.

The great majority of electricity customers and demand are on Peninsular Malaysia, which also hosts the majority of generating infrastructure.

Energy Reserves

As at the end of 2001, Malaysia had proven oil reserves of 3.39 billion barrels. Known reserves of oil have fallen significantly over the past 10 years with the rate of discovery of new reserves failing to keep pace with consumption at current production rates. At the planned rate of consumption, oil reserves are expected to last for 15 years. Malaysia is anticipated to become a net importer of oil by 2008.

Malaysia has large natural gas reserves standing at 82.5 trillion standard cubic feet (TCF). Malaysia's planning goals project a life expectancy of 60 years for proven gas reserves.

Coal reserves are 1,483 million tonnes. In rural areas, particularly in Sabah and the Sarawak coal is used as a cooking fuel. Peninsular Malaysia itself has only small reserves of coal, with Sarawak representing 1,228 million tonnes and Sabah 238 million tonnes. Malaysia is a significant importer of high grade coal for thermal generation plants. In 2001, Malaysia produced 0.46 million tonnes of coal, but consumed 4.7 million tonnes, of this approximately 3.16 million tonnes of coal were used as fuel for power stations.

The estimated total potential hydroelectric power generating capacity is 29,000 MW, with total estimated potential annual output of 123,000 GWhr. Approximately two thirds of this potentially exploitable resource is located in Sarawak.

Malaysia also has significant potential energy reserves from biomass, including palm oil, rice husks, bagasse and forestry residue. It was estimated in 2003 that there was potential for 1,117 MW of installed generation capacity using waste from the palm oil industry. Interconnection procedures to the distribution network and a renewable energy power purchase agreement have been developed for biomass power plant, and the first full-scale grid-based biomass demonstration power plant is being constructed.

Energy Infrastructure

Malaysia has significant energy resources including coal, oil, gas, hydro and biomass. It has an extensive grid system that extends to 93% of the population. The electricity sub-sector is dominated by three integrated utilities, Tenaga Nasional Berhad (TNB) which serves Peninsular Malaysia, Sabah Electricity Sdn. Bhd. (SESB), and Sarawak Electricity Supply Corp. (SESCo) and complemented by a number of independent power producers (IPPs), dedicated power producers and co-generators.

Peninsular Malaysia, Sarawak and Sabah have separate transmission networks and are not interconnected, however, TNB's Peninsular Malaysia network has interconnections to both Thailand and Singapore. As the majority of demand, population and industry, is located in Peninsular Malaysia, TNB is the dominant company in power generation, transmission and distribution. However a number of IPPs are in the market representing approximately 40% of Malaysia's installed capacity. Encouraged by government policy and open bidding for major projects, new IPPs are expected to continue to enter the market and further capacity building is expected from entrenched IPPs.

The entry of small power producers and the use of renewable energy for on-grid end-use has also been encouraged, through the Small Renewable Energy Power (SREP) programme. One example is Matrix Hydro Generation Sdn Bhd, which has received approval from the Ministry of Energy, Communications and Multimedia to implement mini-hydropower generation in four locations in Peninsular Malaysia for a combined capacity of 8.4 MW. Construction of plants, with an estimated project cost of RM 45 million (US$ 11.8 million), can commence within 24 months from 27 January 2003, pending the submission of additional requirements. Off-grid generation using renewable energy has been a feature of many regional palm oil processing plants, some of which have been operating in this way for at least 30 years.

Due to factors arising from the recent regional and global economic downturns, the rate of deregulation has been deliberately slowed while still continuing to be developed.

Transmission System

The transmission grid encompasses 66 kV, 132 kV, 275 kV and 500 kV transmission networks of which 99% are owned, operated and managed by TNB on Peninsular Malaysia. The TNB Transmission Division is responsible for planning, evaluating, implementing and maintaining these transmission assets. Sabah and Sarawak transmission are operated separately to TNB.

Energy Mix

At the end of 2002, Malaysia's installed capacity was 15,121 MW, growing by 5.6% from 14,314 MW at the end of 2001. In 2002, major additional generation capacities were from 2x143 MW gas turbines in GB3 Power Station in Lumut and 2x230 MW from Panglima Power Station in Malacca.

In 2001, Malaysia's installed capacity grew by 4.1% from 13,762 MW at the end of 2000. A substantial part of this growth reflected the commissioning of the first 2 units of the 500 MW Phase III Sultan Sala Huddin Abdul Aziz coal-fired plant.

At the end of 2002, the electricity generation mix was represented by natural gas at 74.4%, fuel oil and diesel at 7.8%, coal at 10.4% and hydro at 6.7%.

Table 17 : Malaysian Electricity Generation Capacity (MW) and Share (%) by Technology Type and Producer

	TNB	SESCo	SESB	IPPs			TOTAL	SHARE
				PM	SWK	SAB	(MW)	(%)
STEAM								
Coal	1,600	0	0	0	100	0	1,700	11.5
Gas	1,200	0	60	0	0	0	1,260	8.5
Oil	360	0	106	0	0	0	466	3.1
HYDRO	1,898	94	66	20	0	0	2,078	14.0
MINI-HYDRO	12	7	6	15	0	0	41	0.3
DIESEL/LFO	0	75	74	0	0	170	319	2.2
RURAL DIESEL	0	28	4	0	0	0	32	0.2
COMB. CYCLE	1,721	0	44	3,580	0	0	5,345	36.1
GAS TURBINE								
Diesel/Oil	68	64	0	0	0	0	132	0.9
Gas	1,805	291	127	880	218	120	3,441	23.2
TOTAL	8,664	559	487	4,495	318	290	14,813	100.0
SHARE (%)	58.6	3.8	3.3	30.3	2.0	2.0	100.0	

Source : National Energy Balance

Power Generation Technology

The main fuel used for power generation in Malaysia is natural gas with combined-cycle technology having the single largest installed capacity. In 2001 36.1% of installed generation capacity used combined-cycle technology. These plants have relatively high efficiency and low greenhouse gas release for fossil fuelled generation. There are also a significant number of open-cycle plants fuelled with gas (23.2% of total installed capacity). While plans exist for refurbishing some of the open-cycle plants as combined-cycle, open-cycle plants are still being constructed or planned for construction.

There has been a focus on utilising fuels other than gas, in particular coal to diversify energy generation mix. It is expected that more coal-fired capacity than gas-fired capacity will be built until 2010. An example is the 2,100 MW capacity pulverised coal-fired plant that is under construction at Manjung for TNB.

Coal-, gas- and oil-fired conventional thermal plants accounted for 23.1% of total installed capacity at the end of 2001.

Hydro power accounted for approximately 14% of installed generating capacity with most hydro generation occurring on Peninsular Malaysia. Sabah and more particularly Sarawak have large potential hydro resources. Hydropower generation does not contribute significantly to greenhouse gas emissions and scope remains to further utilise these resources to minimise greenhouse gas emissions.

Energy Demand

For 2001, total generation was 74,634 GWhr and consumption was 66,445 GWhr. Peak demand for Peninsular Malaysia required 12,680 MW of capacity compared to installed capacity of 13,159 MW. As of 2003, Malaysia has planned for a 7.8% per annum increase in demand until 2005 with manufacturing industry expected to be one of the largest demand growth sectors.

In recent years, growth has been suppressed in this sector by the global economic slowdown, and earlier by the regional financial crisis. Total electricity generated was 0.5% lower in 2001 than for year 2000, due mainly to lower peak demand for manufacturing industries caused by the world economic slowdown. Nonetheless, total net consumption actually increased by 4.5% to 63,043 GWhr in 2001, mainly due to increased domestic and commercial usage. More vigorous growth is expected to return as the global economy improves.

Energy Planning

Energy demand is expected to continue to grow very strongly in line with strong growth in the industrial sector and continuous improvement in living standards, and despite a safety margin of approximately 37% in generation capacity over peak demand for the year 2001, it is expected that significant additional generation infrastructure will need to be commissioned to keep pace with expected demand growth.

The Ministry of Energy, Communications and Multimedia is responsible for energy planning in Malaysia. Under the Energy Commission Act 2001, the Energy Commission (EC) has assumed all the responsibilities of the former Gas and Electricity Commission including maintaining and regulating quality, adequacy of supply, and tariffs. In addition the EC has been entrusted with additional roles and functions, such as promotion of research and development and protecting consumers. The TNB System Planning Unit provides data to the Energy Commission and MECM. Demand forecasting and generation planning functions are performed by EC and MECM. Sabah perform their own forecasting and modeling.

Malaysia follows a number of policy principles in regard to energy planning. In order to ensure diversity of energy mix, Malaysia has placed maximum limits on the quantity of these fossil fuels that can be extracted from internal resources each year. Additionally, the Four Fuel Policy was introduced in 1981 to ensure a balanced mix of utilisation of oil gas, coal and hydropower resources and to maximise security of supply. There has also been recognition of the potential for renewable energy sources to play a significant role in offsetting the use of fossil fuels, thereby preserving indigenous resources. Under the 8th Malaysia Plan (2001-2005) the Four Fuel Policy was extended to recognise renewable energy as the Fifth Fuel for Malaysia's future.

Planning strategies have been outlined in the Third Outline Perspective Plan (OPP3 2001-2010). In 2003, the EIA reported that an expected capital investment of US$ 9.7 billion would be required in the electric utility sector to meet growth. Due to both the Asian financial crisis and the world slowdown, demand has been somewhat less than predicted. For this reason some projects have been postponed to minimise the amount of excess capacity. Malaysia currently has adequate installed power generation capacity, and a number of significant projects either under construction or planned that should ensure adequate supply until the end of 2010.

In line with the recent energy policy additions that promote renewable energy as the fifth fuel source, the government will implement programs to accelerate the development and use of renewable energy in line with OPP3 2001-2010 and the Eighth Malaysia Plan (8MP 2001-2005). The strategies being implemented include promotion of renewable energy resources, such as biomass, biogas, municipal waste, solar, and mini-hydro; in-house biomass-based cogeneration; demonstration projects; and commercialisation of research. Funded research and development will extend not only to established renewable energy resources but will also focus on palm diesel and use of alternative sources such as fuel cell, hybrid cell, and hydrogen fuel. Incentives include fiscal incentives and promotion of cooperation between public and private sectors.

There is also planning for an increase in small renewable energy production for both on and off-grid uses. Growth in the use of cogeneration, driven by commercial need, is expected to continue.

Government Energy Policy and Structure

Malaysia has a comprehensive set of energy policies and bodies in place to meet its strategic national goals. The Ministry of Energy, Communications and Multimedia is responsible for energy planning. The Energy Commission is responsible for ensuring adequate, secure, and reliable supply of electricity and the supply of gas through the pipelines.

The ROLES in the electricity supply sector in Malaysia are as follows:

1. POLICY MAKER - Government
2. REGULATOR - Energy Commission
3. ENERGY SUPPLY AND SERVICE COMPANIES - TNB, SESB, SESCo, and IPPs
4. RESEARCH and DEVELOPMENT and PROMOTION INSTITUTIONS
5. CONSUMERS

Malaysia aims to meet three major strategic objectives in regard to energy planning. These are:

- **The Supply Objective :** To ensure the provision of adequate, secure, and cost-effective energy supplies through developing indigenous energy resources both non-renewable and renewable using the least cost options and diversification of supply sources both from within and outside the country;
- **The Utilisation Objective :** To promote the efficient utilisation of energy and to discourage wasteful and non-productive patterns of energy consumption; and
- **The Environmental Objective :** To minimise the negative impacts of energy production, transportation, conversion, utilisation and consumption on the environment.

All three objectives have implications for greenhouse gas emissions.

Greenhouse Abatement Policy

Malaysia has been exemplary in its strong participation in international initiatives on climate change and energy management. Malaysia is a non-Annex 1 Party under the United Nations Framework Convention on Climate Change (UNFCCC). It signed the UNFCCC treaty on 9 June 1993 and ratified on 1 October 1994, and subsequently signed the Kyoto Protocol on 12 March 1999 and ratified on 4 September 2002. The Government, with the Malaysian Centre for Environmental Studies and the Institute of Strategic and International Studies (ISIS) Malaysia, commenced work on a National Greenhouse Inventory (NGI) and its first National Communication under the UNFCCC in 1997, assisted by the United Nations Development Programme (UNDP). Malaysia finalised its first National Communication under the UNFCCC in January 2000.

Greenhouse strategy has been stated in Malaysia's National Communication to the UNFCCC. For the energy sector, and particularly for electricity, the processes by which projected greenhouse emissions will be minimised are:

- implementation of efficient generation capacity;
- demand side management and energy efficiency initiatives;
- use of biomass and other renewable fuels.

In response to the UNFCCC, Malaysia has initiated a number of programmes, some funded by the Global Environment Fund or other multilateral bodies. These have included surveys on energy efficiency in industry, demand side management and potential for biomass utilisation for power generation. Pusat Tenaga Malaysia (PTM) was established and a comprehensive energy data source, the Malaysia Energy Database Information Service (MEDIS), was established in 1998 as a resource for energy planning and management.

Small Renewable Energy Power (SREP) Programme, the Energy Efficiency in Manufacturing initiative and the establishment of PTM and its associated energy efficiency programmes are examples of Malaysia's response to Greenhouse abatement and Climate Change issues.

7.3 Carbon Dioxide Reduction Options

Malaysia is a growing economy. National economic development will continue to be dependent on industrial growth, particularly in manufacturing and, in turn, will require increasing power generation capacity. The challenge is to meet the increasing demand while reducing the rate of growth of greenhouse gas emissions.

In Malaysia's first National Communication under the UNFCCC, projections were made for greenhouse gas emissions using Business as Usual (BAS) and Efficiency-Oriented (EO) scenarios projecting expected energy efficiency gains of 10% by 2010 and 20% by 2020 for electricity over a base year of 1990, with a population base of 17.2 million in 1990 and 32 million projected for 2020.

The Phase I report for this project identified 19 options as having significant potential for greenhouse gas abatement. A number of these are applicable to the scenario as it stands in Malaysia, and are being implemented, or could be implemented for either existing or planned plants.

Table 18 : Energy Input to Power Generation 2001

Fuel	Energy Input (ktoe)	Energy Input Share (%)	Greenhouse Emissions ($ktCO_2$)
Natural Gas	11,922	71.7	28,000
Coal	1,194	12.0	7,900
Fuel Oil/Diesel	1,080	6.1	3,100
Hydro	1,678	10.2	0
Total	16,615	100.0	39,000

(Source : National Energy Database 2001)

The total energy input into power generation in 2001 excluding co-generation and private power plants (off-grid) was reported as 16,615 ktoe (NEB). The breakdown into different fuels is given in Table 18. Total greenhouse gas emission for generation would be equivalent to 39,000 kt CO_2, with a greenhouse intensity of 0.55 t CO_2/MWhr. At least 34% of gas was used in open-cycle gas turbines. Conversion of all open-cycle plants to combined-cycle technology, with a conservative 20% reduction in fuel usage (Phase I report), and unchanged power generation, would equate to a potential reduction of greenhouse emissions by 1,903 kt CO_2 per annum. If we also assume the 5% target for biomass (2005) is successfully met and that distribution system losses will be improved from 15% to 10% greenhouse intensity for power generation could be reduced to 0.47 t CO_2/MWhr.

7.3.1 Technology Improvements

The majority of installed capacity in Malaysia is gas-fired. The most common technology is combined-cycle and, therefore of relatively high efficiency and relatively low greenhouse gas emissions per kWhr of electricity generated. However, there are also a significant number of plants using open-cycle technology in operation. Conversions to combined-cycle reduce greenhouse gas emissions, can be cost effective and can also enable the delay of construction of new plant and supporting infrastructure elsewhere. Conversion of some existing open-cycle plants to combined-cycle has been undertaken. Many of the current open-cycle plants are used for peaking capacity, therefore conversion of the installed base of open-cycle generators to combined-cycle would require technology which would maintain their ability to operate as peaking plants. The new versatile CCGT plants that can retain open-cycle operation make upgrade of more plant feasible.

Hydropower accounts for 14% of capacity and approximately 10% of generation (2001) and produces minimal greenhouse gas emissions. There is significant potential for increased use of hydro resources, particularly given the huge potential resources available from Sarawak. Projects are under construction and more are planned. There is also potential for export of electricity from hydropower generation to neighbouring APEC nations, which has the potential to reduce emissions from importing nations that would otherwise require commissioning of thermal fossil fuel generation. Additionally, micro-hydro power generation is also being encouraged, with approval having been granted for a number of both on and off grid projects.

Conventional thermal generation in Malaysia is fuelled by coal (1,700 MW), gas (1,260 MW), and oil (466 MW). Currently, all steam turbine generation is based on subcritical plants. Conversion of existing gas- and oil-fired turbines to combined-cycle gas turbine has the potential for significant efficiency increases. By utilising existing plant and taking advantage of increased efficiency and generation gains, as demonstrated by the accompanying case studies in this report, these types of conversions can be very cost-effective.

Review of existing coal-fired plants and improvements to combustion and steam cycle, as detailed in the Phase I Study, could lead to improvements in efficiency of up to 3.5% and subsequent reductions in greenhouse gas emissions. Plants would have to be evaluated on a case-by-case basis for capital investment and pay back period, and taking into account National circumstance. In line with the National Depletion Policy, which seeks to limit the rate of usage of oil and gas reserves, it is anticipated that the majority of new capacity to be constructed through to 2010 will be thermal coal. Ensuring that new plant is of supercritical design would minimise greenhouse emissions compared to new subcritical plant.

Biomass has insignificant greenhouse emissions compared to fossil fuel generation. Malaysia has significant potential energy reserves from biomass. It has been estimated that, in 2003, palm oil industry waste had potential to provide sufficient energy for 1,117 MW of installed generation capacity. Apart from palm oil waste, rice husks, bagasse, and forestry residue are other potential biomass fuels. The Energy Commission are developing grid access regulations and buy-back power rates and the first grid-based biomass power plant started construction in 2003. Incentives are in place for approved renewable energy projects and can include income tax exemption or investment tax allowance on capital expenditures; import duty and sales tax exemption on imported machinery and equipment; and sales tax exemption for domestically produced machinery and equipment.

Co-generation provides a potential opportunity for greenhouse gas abatement. Malaysia has no specific policy on co-generation except for renewable energy projects, as noted earlier. Co-generation has the potential for significant commercial advantages, where there is a requirement for both heat and power. Commercial imperatives have driven and should continue to drive significant investment in co-generation for industry.

7.3.2 Other System Improvement Opportunities

Malaysia has embarked on a number of other initiatives and policies that have the potential for greenhouse gas emission abatement. These include demand and supply side measures and other infrastructure improvements.

Competition Efficiency

Experience of privatisation and implementation of a competitive electricity market has been found to provide overall efficiency benefits. At the moment, Malaysia's power generation and transmission continues to be dominated by TNB (58.6% of total installed capacity), there are 2 other state-owned power generators, and 15 IPPs were licensed soon after the market was opened to competition in 1994. IPPs account for a further 30.3% of installed generation capacity in Peninsular Malaysia. TNB manages almost all transmission and distribution assets. Malaysia is reviewing the future shape of the industry. Earlier plans to achieve a fully competitive power market, with decoupled generation, transmission, and distribution are being reviewed.

Transmission Losses

Transmission and distribution losses make up a significant proportion of supply irrespective of source of generation. In Malaysia, in 2002, losses for Peninsular Malaysia were 14.9% and for Sarawak and Sabah were 15%. System losses actually increased from 12.7% for Peninsular Malaysia in 1985.

In general, transmission losses increase with distance travelled and decrease with increased transmission voltage. Careful planning of major new projects can reduce losses due to transmission. In planning for new plants, each project must submit an environmental impact statement. The location and access to grid and distance to the target consumers are factors taken into consideration in the planning and approval process.

TNB Distribution Sdn Bhd, a wholly owned subsidiary of TNB, will spend RM 320 million (US$ 84.2 million) over four years to upgrade the national electricity distribution network. The upgrading works include replacing cables, rehabilitating 20-year-old switchgears, increasing transformer capacity and replacing transmission lines. The system upgrade is expected to provide major benefits to industrial areas and nearby domestic and commercial users comprising 80% of TNB's customers, but the remaining 5.1 million domestic users are also expected to see significant improvements.

Refurbishing Hydro Power Stations

This possibility was not included in the original 19 scenarios. In essence a refurbished plant provides more capacity to the system at a cost but no increase in greenhouse gas. This has the potential to offset greenhouse emissions growth from fossil fuel-fired plant that would otherwise be utilised.

Demand Side Management

Demand side management opportunities have been identified and form the basis for a number of government policy initiatives and research and development programmes. Implementing bodies include the PTM, which has an overriding coordinating and implementation role. The Malaysian Industrial Energy Efficiency Improvement Programme (MIEEIP), implemented by PTM and co-funded by UNDP and Global Environment Facility (GEF), commenced in July 1999 and aims to contribute to greenhouse abatement by improving end use energy efficiency in Malaysian industries. Industry accounts for almost half of all power consumption in Malaysia, and industrial growth is expected to be one of the driving factors for continuing growth in demand.

Biomass Co-generation

Domestic off-grid biomass co-generation has been identified as having significant potential for rural and remote areas. Many examples are already in place. Successful implementation of this technology reduces greenhouse emission and can also reduce the need for additional grid generation.

7.3.3 Prioritisation of Options

Malaysia has not set priorities for improvement options but implements on a case-by-case basis. Each proposed project must submit an Environmental Impact Statement (EIS), which will be assessed before a license for the project is issued. The EIS includes emissions to air, allowing assessment of greenhouse emission impacts during the approval process.

Malaysia's Fuel Depletion Policy means there is a significant emphasis for new generation capacity to be based on coal-fired generation. All future plant of this type must include clean coal technology. There would only be incremental additional costs if all proposed new coal-fired plant were specified to be supercritical design rather than subcritical. Significant greenhouse abatement would ensue as well as longer-term efficiency and consequent cost savings. Refurbishment of the currently installed base of subcritical coal-fired power stations would require significant capital expenditure, but could probably be carried out at a far lower cost per kW than construction of new plant.

7.4 Perceived Barriers

Availability of capital to carry out new projects or refurbish existing infrastructure is a primary barrier for all major projects. The regional financial crisis and associated recession and now the world economic slow-down and particularly the collapse of several energy companies in the United States market, has made accessible capital more cautious. However, the stability of government and strength of economic fundamentals, including the rebound to stronger growth, ensures that Malaysia is seen as possessing an attractive destination for investment. This is tempered by equity requirements for new investments, including renewable energy where a local equity must be at least 30% and an individual foreign entity can have no more than 30% equity in new renewable projects. The entry of IPPs into the market has allowed additional capital inflow. The float of TNB provided significant capital and subsequently, TNB has been successful at raising capital through both foreign and local bond issues. However, capital markets remain risk averse, to technologies perceived as being new or emerging. It is hoped that experience, as exampled by the accompanying case studies, combined with complete life-cycle analysis can contribute to the uptake of the extensive opportunities available through the use of efficient generating technologies.

The second barrier is the rate at which a competitive market is being developed. The present timetable sees a partly competitive electricity market by 2010. The efficiency improvement due to the market could be brought forward by a number of years with consequent improvement in performance and greenhouse gas reduction.

Technology is seldom seen as a barrier as it can be either sourced locally or imported. Malaysia supports a range of research and development programmes that look at both conventional and renewable technologies. An example is biomass generation, which was identified as a potential significant energy source for generation. Research was undertaken and in 2001, a licence was issued for the first full-scale biomass generation plant utilising palm oil industry waste.

The rate of growth of electricity demand is seen as a barrier to the implementation of refurbishment projects. Even with its current significant excess of generation capacity, the high rate of growth and volatile world economy, pose a very significant risk of supply constriction if plant is taken out of service for refurbishment or repowering.

7.5 Government Initiatives

Malaysia has a comprehensive system of policies and initiatives for the growth and refurbishment of the power system.

7.5.1 Necessary Policies

At an early stage, a programme of research, data gathering and surveys was developed to allow planning of strategies to mitigate greenhouse emissions on a "no regrets" basis. These have been integrated within the policy frameworks already in place to ensure quality, stability, continuity and adequacy of supply, which will meet the Supply, Utilisation and Environmental National Objectives for energy.

Under the Supply Objective, sustainability and security of supply is addressed by the National Depletion Policy which addresses energy mix and that incorporates the original Four Fuels Policy, which has now been extended to include renewable energy as the Fifth Fuel for energy production and power generation.

The Utilisation Objective promotes the efficient utilisation of energy resources and reduction of waste, and incorporates demand-side management and energy efficiency. Energy efficiency regulations are currently being formulated which will focus on designation of large consumers, appointment of energy managers for large consumers and equipment labelling. Programme initiatives include the Malaysian Industrial Energy Efficiency Implementation Programme (MIEEIP), jointly funded by the GEF and Malaysian Government and implemented by PTM.

The Environmental Objective, focuses on quantifying potential impacts and minimising the negative impacts of energy production, transportation, conversion, utilisation and consumption on the environment, including greenhouse impacts. All new projects and upgrades must undertake an EIS, which must be meet Environmental Objectives before project approval. Other policies and programs in place include:

1. Target Setting
Malaysia's renewable energy policy calls for an ambitious target of 5% (or 500 MW), to be implemented by 2005, mostly comprising of grid-based biomass power plants. At November 2003, 50 projects had been approved for a total capacity of 310 MW, with 265 MW grid connected.

2. Grid Connection for Renewable Energy Projects
The Small Renewable Energy Power (SREP) programme enables small power generation plants that utilise renewable energy to sell electricity to the utility companies through the distribution grid system.

3. Investment Incentives/Subsidies for Renewable Energy Projects
Project developers of qualified biomass-based power projects can access a variety of investment incentives including income tax exemptions or investment tax allowances, import duty and sales tax exemptions on machinery and equipment.

4. Pricing
Price regulation is maintained by the Energy Commission. Generation from renewable energy and highly efficient plants must compete for capital within the market with generation from other sources.

5. Power Purchase Agreements
Power purchase agreements (PPAs) for selling electricity to the grid are negotiated with the individual utility. Some previous long-term guaranteed PPAs between the Government and IPPs, were transferred to the privatised TNB. After the slow-down in demand growth due to the economic downturn, the economic viability of some PPAs was questioned.

6. Energy Efficiency and Demand Management
Energy efficiency programmes including demand-side management have been addressed under the Utilisation Objective. The Energy Commission is responsible for research, development and promotion of energy efficiency. The government has partnered with TNB in setting up the Demand Side Management (DSM) Project. The Low Energy Office (LEO) Project at Putrajaya is a demonstration project relevant to commercial and industrial premises. PTM has implemented a range of energy efficiency programmes including the successful industrial energy efficiency programme.

7. Education, Training and Awareness Programmes
Education, training and awareness programmes are indirect measures that help promote positive attitude towards renewable energy among the general public. The current trend is to share information, to identify technology transfer opportunities, and to increase public awareness of the positive attributes of renewable energy. The Centre for Education and Training on Renewable Energy and Energy Efficiency (CETREE) is a central resource for information, education and promotion of renewable energy. PTM are responsible for energy efficiency for the industrial, commercial and domestic sectors.

8. Permits, Grid Access Regulations and Environmental Compliance
Malaysia has developed guidelines on securing permits for installation of new projects and grid access, for both thermal and renewable energy projects. Each new project over 10 MW must produce an Environment Impact Statement, which includes atmospheric emissions but does not necessarily include greenhouse emissions or impact.

7.6 Action Plan

Malaysia, both in its initial communication to the UNFCCC and through its utilisation and environmental objectives, has outlined actions that will impact greenhouse emissions based on the "no regrets" principle, but a consolidated action plan specifically for greenhouse and power has not been made. However, comprehensive set of policies, and initiatives on energy and power generation have been put in place and those relevant to greenhouse emission reduction can be summarised. Some initiatives, such as incentives for renewable energy use, can be said to extend beyond the "no regrets" approach.

Malaysia's current action plan can be summarised as:

- Expand renewable energy use, as illustrated by biomass demonstration plant and major hydro projects to utilise large exploitable hydropower reserves. Encourage renewable energy projects through incentive schemes;
- Maintain and accelerate demand-side programmes including industrial energy efficiency, energy auditing program, energy service companies support program and technology demonstration programs and expand these to commercial and domestic energy sectors in areas such as equipment and appliance energy labelling and building and home design;

- Upgrade transmission and distribution systems to realise system efficiency gains due to transmission loss reductions whilst improving supply quality;
- Refurbish existing open-cycle gas to combined-cycle where appropriate;
- Ensure new coal-fired plant utilises clean coal technologies;
- Review status of pace and scope of privatisation and competitive electricity market reforms at a measured pace in-line with National Objectives;
- Utilise multilateral CDM, GEF, opportunities and bilateral opportunities (partnerships with Japan) to help fund and implement GHG emission reduction projects.

Additional measures that could be considered include:

- Prioritise initiatives on the basis of cost effectiveness;
- Implement a greenhouse abatement policy which includes setting of efficiency and greenhouse gas intensity targets;
- New coal-fired power plants to be supercritical. Malaysia has signalled an intention to construct more coal-fired capacity in addition to utilisation of biomass and gas turbine generation. An example is the 2100 MW Manjung coal-fired power plant, currently under construction, that is being built as a subcritical seawater-cooled plant. Utilisation of supercritical technology would have produced significant efficiency gains, and reduced greenhouse emission intensity. A policy initiative for all future coal powered plants to utilise more efficient supercritical or ultra-supercritical technology would cost-effectively reduce greenhouse emissions;
- New supercritical coal-fired plants could incorporate continuous cycling, and fast start technologies (see the Yonghung case study in this report) that would help meet peak demand while better tailoring capacity to demand.
- Provide access to capital or incentives for investing in improved efficiency and greenhouse gas abatement measures;
- Generation from renewable energy and highly efficient plants must compete for capital, within the market, with generation from other sources. Often the capital cost of more efficient and lower greenhouse emission technologies will be greater than for other technologies but will have a payback over time from lower cost per MWhr of generation. In a capital constrained market the solution requiring lower initial capital investment will often win out. In some countries, incorporation of full life-cycle cost analysis during the project approval process has been used as a selection criteria during the project approval process. Incentives including tariff differentiation for more efficient plant can also be used to influence capital markets;
- In some countries, voluntary programmes, where consumers can opt to pay a premium for green-energy, have been used to drive increased generation from renewable or low greenhouse emission technologies;
- Explore the Clean Development Mechanism (CDM) as a tool to promote greenhouse gas reduction projects in the energy sector.

7.7 Appendices

7.7.1 References

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7.7.3 Notes

Most recent data (31/12/2001) from MEDIS report, National Energy Balance (NEB) 2001 supplemented by other resources has been used as far as possible. A new NEB is due for release by the end of December 2003.

Data from the Malaysia's First Communication to UNFCCC Initial Response paper was finalised in 2001, and report for the base-line year, 1988, and first report year, 1997.

7.8 Glossary

ACE	ASEAN Centre for Energy
ADB	Asia Development Bank
APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of South-East Asian Nations
BAS	Business as Usual
BNM	Bank Negara Malaysia
CCGT	Combined-Cycle Gas Turbine
CDM	Clean Development Mechanism
CETREE	Centre for Education and Training on Renewable Energy and Energy Efficiency
CO_2	Carbon Dioxide
DSM	Demand Side Management
EC	Energy Commission
EIA	Energy Information Administration
EIS	Environment Impact Statement
EO	Efficiency Orientated
GDP	Gross Domestic Product
GEF	Global Environment Facility
GW	Giga Watt
GWhr	Giga Watt Hour
IPP	Independent Power Producer
ISIS	Institute of Strategic and International Studies
JICA	Japan International Cooperation Agency
KLCC	Kuala Lumpur City Centre
KLIA	Kuala Lumpur International Airport
KLSE	Kuala Lumpur Stock Exchange
ktoe	Kilo Tonnes Oil Equivalent
kV	Kilo Volt
kW	Kilo Watt
kWhr	Kilo Watt Hour
LEO	Low Energy Office
MEDIS	Malaysia Energy Database Information Service
MIEEIP	Malaysian Industrial Energy Efficiency Improvement Programme
MP	Malaysia Plan
MW	Mega Watt
NEB	National Energy Balance
NGI	National Greenhouse Inventory
NUR	Northern Utility Resources
OPP	Outline Perspective Plan
PM	Peninsula Malaysia
PPA	Power Purchase Agreement
PTM	Pusat Tenaga Malaysia
SAB	Sabah
SESB	Sabah Electricity Sdn. Bhd.
SESCo	Sarawak Electricity Supply Corp.
SREP	Small Renewable Energy Power
SWK	Sarawak
TCF	Trillion Cubic Feet
TNB	Tenaga Nasional Berhad

TNBH	Tenaga Nasional Berhad Hidro
TNBJ	Tenaga Nasional Berhad Janamanjung
UNDP	United Nations Development Program
UNFCCC	United Nations Framework Convention on Climate Change
WDB	World Development Bank

8. TARGETED ECONOMY REVIEW - VIET NAM

8.1 Economy Summary

Viet Nam is a developing economy with an exceptional growth rate in energy and electricity requirements. It has adequate energy resources for the present and is using these wisely to keep up with demand for power and at the same time achieving a good balance of the key energy supply factors.

With respect to climate change, it has taken its part in international discussions and commitments and is managing the energy mix for the economy in an efficient manner that contributes to minimising greenhouse gas release and provides for effective development of its resources.

Viet Nam has more than 50% of its power sourced from hydro with about 30% from domestic gas and 20% from domestic coal. It is driving its hydro installations with a capacity factor of 80% and fossil plant with a much lower capacity factor. In the event of drought, it has the capacity to maintain supply albeit at higher greenhouse gas production.

While Viet Nam has an ambitious Power Development Plan, there are a number of initiatives that could be activated to achieve greater greenhouse gas abatement without affecting other important factors significantly.

With respect to installed capacity, there are older coal-fired installations of 900 MW installed capacity that could be refurbished to improve their efficiency. There are also older hydro installations comprising 4,000 MW that could be refurbished to increase their output and replace fossil generation. There are 2,500 MW of older gas-fired units some of which could be converted to combined-cycle operation.

Considering the interconnected power system, improvements to transmission will reduce losses from 14 to 10% by 2010, which is equivalent to extra generation.

Viet Nam has planned for the introduction of competition in stages by 2010. Experience in other economies has shown a significant overall efficiency improvement accompanies competition. Viet Nam could accelerate the development of a competitive market and take advantage of this efficiency gain earlier.

Like many other Asian economies, Viet Nam recognises the importance of nuclear generation. While it has placed this initiative at 2020 because of the need to train personnel, there is a strong climate change case to accelerate this possibility.

Taking the 2001 Power Development Plan (PDP) as a basis and adding the above changes, there is the practical possibility of reducing greenhouse gas release from 0.3 t CO_2/MWhr to 0.23 t CO_2/MWhr or a saving of about 5 million tonnes of CO_2 per annum in 2010.

8.2 Introduction

In any economy, there is an ongoing need to provide adequate energy for the beneficial development of that economy. The main driving force in this is defining and managing the energy mix for the economy. In particular, for electricity supply the energy resource mix used must reflect a number of key factors.

The primary factor is security of supply so that electricity is available when needed. Other key factors that must be considered are the stability of the interconnected power system, the capital and operating costs of the supply system, the electricity price that the population can afford, and the environmental implications of operating the power system.

Economies tend to utilise domestic energy resources to save foreign exchange where possible. Viet Nam is endowed with adequate energy resources for the near and intermediate future.

There is therefore a responsibility to supply reliable power, using primarily indigenous resources, at an acceptable community cost. Environment matters, such as climate change and public health, need to be considered with cost of power and system reliability in meeting the long-term needs of Viet Nam.

8.3 Economy Description

8.3.1 General

Viet Nam is a rapidly growing Asian economy. It has a large literate workforce and a liberal foreign investment code. It has an effective energy development plan seeking to change from an agricultural base to an industrial one.

Population

The population of Viet Nam was 78.1 million in 2003 with an annual average growth rate of 1.4%. One third of the population is under 15 years of age and 5% are over 65.

Geography

The mainland of Viet Nam occupies an area of 330,000 sq. km. It has 3,260 km of coastline and many islands off the coast.

Industry

Industry made up about 35% of GDP in 2003, employing 13% of the workforce.

Agriculture

Agriculture made up about 23% of GDP in 2003, employing 70% of the total workforce.

Socio Economic Information

The GDP per capita in Viet Nam was about US$ 400 in 2003. The electricity consumption per capita was 340 kWhr in 2003 compared with its neighbours, Thailand 2,000 kWhr, China 1,200 kWhr, Malaysia 2,500 kWhr and Singapore 5,000 kWhr. Viet Nam considers that it should target an electricity per capita figure of about 3,000 kWhr to become an industrial economy.

It is planning to increase the electricity consumption per capita value of 340 kWhr in 2003 to about 1,800 kWhr in 2010. This implies major expansion in generation both to meet population growth plus increase in per capita usage to improve the standard of living. It has a major energy conservation program for industry and presumably this would be extended to the domestic sector over the same time period.

This growth will be coupled with major domestic greenhouse abatement in changing homes using coal as fuel at 17% efficiency to briquettes at 27% efficiency and then to use electricity at 35-50% efficiency from gas- and coal-fired power stations plus hydro generation. The change from coal to electricity domestically will also improve public health significantly by reducing the level of local and indoor pollution.

Political Situation

With respect to energy supply, Electricity of Viet Nam (EVN) is a state-owned utility established in 1995. It provides electricity generation, transmission and distribution for the Viet Namese economy. It is a complex organisation with separate sections dealing with plant design, plant manufacture and telecommunications in addition to power generation, transmission and distribution.

It has recently contracted private generators to supply power on long-term contracts at agreed prices. This has allowed it to husband its capital successfully.

Vinacoal, the anthracite coal mining organisation in Viet Nam also generates power from a number of coal-fired power stations for supply to the EVN power system.

8.3.2 Energy

Viet Nam has ample natural domestic energy resources for the present and until at least 2015. It has proven oil reserves of 390 million tonnes, gas reserves of 617 billion cubic meters and coal reserves of 3,325 million tonnes. It gives high priority to thermal plants using indigenous coal and gas and to hydro power. It is an exporter of oil and anthracite.

Energy Infrastructure

Viet Nam has a number of large rivers providing the opportunity for hydro generation. In the north of the economy it has large reserves of anthracite which is mined for export and for use in coal-fired power stations. In the south it has significant offshore gas fields being developed.

It has an extensive power supply system covering about 86% of the economy. It is interconnected with neighbouring economies and the development of the Greater Mekong Subregion (GMS) Power Grid will eventually interconnect at least Viet Nam, China, Myanmar, Thailand and Cambodia.

Energy Mix

In 2001, the total installed capacity in Viet Nam was 8,478 MW of which 7,878 MW were owned and operated by EVN and 600 MW by independent power producers (IPPs). Of this total, 48.6% was hydro power, 13.4% coal and oil, 30.8% gas turbine and diesel and the remaining 7.2% from IPPs with mixed fuels.

Total generation in 2001 was 30,600 GWhr with the proportion of hydro 59.5%, coal 10.5%, oil 3.6%, gas turbine 14.4% and 7% turbine plus diesel together with 4.9% from IPPs. In 2002, the energy mix was hydro 54%, thermal 22%, gas turbine 20% and diesel 5%.

Power Generation Technology

There are four main power generation technologies used in Viet Nam. The largest of these is hydro power from dams on the many rivers. These range from mini hydro to large facilities. Power from this resource does not impact significantly on greenhouse gas release. The continued high capacity factors for this plant in the power system indicate that this technology is preferred for minimising power cost and at the same time improving greenhouse abatement.

Offshore gas fields supply a number of gas-fired power stations. The more recent of these are combined-cycle with relatively high efficiencies and low greenhouse gas release.

There is a considerable anthracite resource in the northern region that is mined, coal being exported and used for power generation.

This combination of electricity generation facilities has the capacity to produce cheap electricity from hydro with enough fossil capacity to supply when water is not available. Excessive dependence on hydro power can cripple an economy, from an energy viewpoint, such as Sri Lanka, New Zealand, and Scandinavia have found in the recent past.

Energy Demand

To ensure adequate electric power for the development of Viet Nam the 2001 Power Development Plan (PDP) was resolved by the 9th Communist Party Congress. In this plan domestic demand is forecast to rise by 15% per annum in 2001-5. It is then forecast to rise by 13% per annum in 2006-10. The likely range of values is shown below.

Table 19 : Predicted demand growth to 2010

Year	Maximum Load, MW	Energy, GWhr
2000	4,900	26,600
2005	7,800 - 8,300	46,500 - 50,000
2010	12,000 - 14,000	70,000 - 80,000

Energy Planning

The long-term Power Development Master Plan covering 2001-2010 was approved in 2001. This program envisages a reserve margin of about 25% for a considerable period. Provisional long term energy development plans extend towards 2020.

With respect to hydro there are 4,000 MW of plant installed or under construction capable of generating 18,000 GWhr. By 2010, the plan calls for a total of 8,000 MW with production of about 30,000 GWhr.

Beyond 2010, the Son La project will add 2,400 to 3,600 MW between 2012 and 2016. None of this plant is of concern for greenhouse gas abatement. However, of the 4,000 MW presently in service a significant proportion could be refurbished with increase in output with no effect on greenhouse gas release.

The present gas-fired capacity is about 2,500 MW. By 2010, there is expected be 6,500 MW of gas-fired plant using 6.5 billion cubic meters of gas per annum. New plant will be in the southern region with 3,800 MW at Phu My and 1,320 MW at Ca Mau and O Mon.

The capacity of present coal-fired plant is 900 MW. Most of this plant is or will be in the northern region, in Quang Ninh province. Since 2001, the 600 MW unit, Pha Li 2, has been completed. By 2010, about 3,000 MW of coal-fired plant are planned to be operating.

This array of new generating plant will ensure adequate electricity supply with a planned reserve margin of about 25%. This level of reserve will be needed if drought reduces the proportion of hydro power available over an extended period.

Improvements to transmission and distribution systems are projected to reduce system losses from 14% in 2001 to 10% in 2010.

This plan and list of proposed new power stations was updated by Balce in a paper to the Asian Corporate Conference in 2003 with somewhat lower figures, showing continuous reconsideration and modification to match economic developments.

As an example of the developing EVN situation, showing the involvement of independent power producers (IPPs), the range of units for the Phu My gas-fired complex are set out below. This complex consists of a number of generators with a total capacity, when completed in 2004, of 3,875 MW. The complex is in Ba Ria, Vung Tau province, 70 km southeast of Ho Chi Minh City. It uses gas from the Nam Con Son field.

Phu My 1 is a 1,090 MW gas-fired combined-cycle. Phu My 2.1 is two 300 MW gas-fired open-cycle units and two 150 MW auxiliary units.

Phu My 2.2 is a gas combined-cycle 715 MW unit. It is the first private infrastructure build own transfer (BOT) project by the Mekong Energy Company (MECO), a consortium of EDFI, Sumitomo and TEPCO with a 20 year contract to supply power to EVN at about US$ 0.0404 / kWhr. It also will run in 2004. This plant will release capital for EVN to invest elsewhere.

Phu My 3 is a gas combined-cycle 715 MW unit, costing US$ 420 million, owned by a consortium of BP, Sembcorp, Kyuden International and Nissho Iwai due to run in 2004.

Phu My 4 is an EVN gas combined-cycle 450 MW unit due to run in 2004.

Viet Nam sees that it has adequate local energy resources of coal, oil, gas and water until 2015. Beyond this, it will need to import some power by linking into the 10 ASEAN member electricity network.

The government has also announced plans to build its first nuclear plant in about 2020.

Energy Policy

Power sector reform started in 1995 when the economy began to develop a market approach to electricity. These reforms aim at separating generation, transmission and distribution and improving financial and information technology at EVN. At the same time, EVN will reduce its capital needs by allowing independent power producers to operate in the market. Initially this will be by way of power purchase agreements.

As part of this program, it is intended to turn one state owned district utility into a joint stock company that is publicly and privately owned. Within three years from 2001 20% of generation is expected to be from private operations.

Power sector restructuring in Viet Nam has notionally been divided into three stages. In the first stage (from 2001 to 2005), EVN will introduce independent accounting programs for some generators and transfer pricing of electricity to transmission companies. This will proceed over a three to five year period in an effort to identify and reduce cost. The remaining generators will be centrally controlled. Distribution companies will purchase electricity from EVN and sell to customers.

In the second stage (from 2006 to 2010) EVN independent accounting power stations will compete with IPPs, selling bulk power to transmission based on power purchase agreements. This will then be extended to all power stations. Transmission Companies will be unified into one organisation. This resulting company will buy power and sell to distribution companies and large customers.

In the third stage (beyond 2010), IPPs and BOT plants will participate in a competitive market on an hourly basis selling electricity to the Transmission Company. The government will manage the Transmission Company in line with its economic development strategy. Distribution Companies will buy from the Transmission Company and sell to customers.

A program, commenced in 2002, will link Viet Nam with surrounding economies by high voltage power lines to facilitate electricity exchange between the Greater Mekong Subregion (GMS) economies. Viet Nam is in a position to export surplus power up to 2007 and then may become an importer under some interconnected system conditions.

Greenhouse Abatement Policy

With respect to the Kyoto Protocol adopted in 1997, Viet Nam is a non-Annex I Party. It has signed the United Nations Framework Convention on Climate Change (UNFCCC) and ratified it in 1994. It also signed the Kyoto Protocol in 1998 and ratified it in September 2002. Since then, it has conducted studies and activities on climate change. Much of this has been undertaken with the assistance of international agencies.

The Viet Nam Government has assigned the Ministry of Natural Resources and Environment (MONRE) (formerly the Hydrometeorological Service) as the national authority to implement UNFCCC and Kyoto Protocol requirements, through the National Office for Climate Change and Ozone Protection (NOCCOP).

A Viet Nam Climate Change Country Team (VNCCCT) was formed in 1994 to improve knowledge on climate change and its impact on the economy. Viet Nam established the Clean Development Mechanism (CDM) National Authority (CNA) in March 2003 under

MONRE. Viet Nam is carrying out a National Strategy Study (NSS) on CDM projects, supported by the Government of Australia through the World Bank, and the 1st National Communication has showed potential savings in the energy sector.

Viet Nam has a major energy conservation policy for the following industries, food, beverage, tobacco, pulp, paper, printing, chemicals, petroleum, coal, rubber, plastic, ceramics, glass, cement, iron and steel.

8.4 Carbon Dioxide Reduction Options

It must be noted that when considering individual technologies it is possible to allocate a definite greenhouse saving to a technology, presuming it is in service 100% of the time, for comparison purposes.

Once there are a number of different technologies represented in a power system this cannot be done because the capacity factors of the different technologies cannot be predicted with any certainty. Greenhouse savings can be suggested for every technology separately and notionally combined with estimated capacity factors. Appropriate technology improvements are suggested below to enhance the 9th PDP now in progress.

8.4.1 Technology Improvements

There are many possible options having significant potential for greenhouse gas abatement. Some nineteen options were evaluated in Phase I of this APEC Project. Further options have been identified in this document. With respect to Viet Nam there are essentially three major energy resources for consideration.

The first energy resource is hydro power which was not listed in the original nineteen scenarios because it does not generate significant greenhouse gases. However, when considered on a power system basis, any refurbishment of older hydro power stations results in additional power for the system with no extra greenhouse gas release. This is a significant option for Viet Nam and is discussed below.

The second energy resource is gas-fired power generation. Most of the new plant is combined-cycle with a high efficiency and little chance for immediate improvement. However, a proportion of older open-cycle plant could be refurbished and converted to combined-cycle, with improved efficiency and improved greenhouse gas abatement. This was one of the previously listed scenarios.

The third energy resource is coal-fired power generation. There are two areas where improvement could take place. New plant is proposed over the next 10 years. At present, this seems to be subcritical technology so that a change to supercritical design or integrated gasification combined-cycle would improve efficiency considerably. With respect to older power stations, refurbishment could improve their performance by up to 5%. Again these were previously listed scenarios.

It is also noted that EVN has planned to introduce nuclear power in 2020 based on local uranium resources and necessary training of potential staff. Nuclear power is extremely greenhouse effective and bringing this decision forward has the potential to improve abatement. New nuclear power stations are becoming available in modules from 200 to 1,000 MW. This technology is becoming important, particularly in Asia.

8.4.2 System Related Improvements

In addition to the specific technology options above, there are a number of abatement opportunities arising from the power system itself.

Transmission Losses

Transmission losses make up a significant proportion of supply irrespective of source of generation. The PDP identifies an improvement in system losses of 4% for the first period to 2010. A further improvement of 3% by 2020 would be reasonable. This is generation capacity released by improvements in high-voltage transmission. As the new lines are required for other reasons this improvement comes at no direct cost.

Refurbishing Hydro Power Stations

This possibility was not included in the original nineteen scenarios. In essence a refurbished plant provides more capacity to the system at a cost but no increase in greenhouse gas. This can be included in calculations.

An example of this is the US$ 4 million contract between EVN and Ukrinternergo to restore the Thac Ba hydro power station in northern Yen Bai province. This is one of an ongoing set of projects.

Competition Efficiency

A further performance improvement arises from the introduction of a competitive electricity market. In the case of Viet Nam this is limited to the generation sector. From Australian experience, an improvement of 1% in overall efficiency for thermal plant was found in Australia with the development of a competitive electricity market. This improvement could be achieved earlier by the more rapid adoption of a competitive market in Viet Nam.

8.4.3 Prioritisation of Options

The priority order to implement these additional proposals is obviously linked with return for investment. Many of the proposals are, however, defined on a case-by-case basis so that the priority list cannot be defined accurately until project costs are known. The following list is therefore proposed based on knowledge of similar projects in Asia.

The improvements in power from loss reduction due to transmission augmentation come at no direct cost and so must be placed first in priority.

The improvement in performance due to bringing forward the competitive generation of electricity is a function of improved accounting methods and is relatively inexpensive. There is a good case to give this a high priority.

Changing new coal-fired plant from subcritical to supercritical and perhaps to IGCC is an incremental cost that could be included in the design stage and in the financial arrangements for new plant.

Refurbishment of older coal-fired and hydro power stations would certainly be an additional expense but could probably be carried out at a far lower cost per kW than installing equivalent new plant. Similarly, conversion of gas open-cycle to combined-cycle would be highly cost effective.

The present industrial energy conservation program could be extended to the domestic sector at little cost. Domestic customers should be encouraged to use energy as efficiently as practical even though the government drive is the increase the per capita consumption from 340 kWhr to 1,800 kWhr by 2010.

The ability to consider nuclear plant introduction could be brought forward easily as the immediate need is only to start training personnel which is relatively inexpensive.

8.5 Perceived Barriers

There are a number of perceived barriers to improving greenhouse abatement in the Viet Namese context. The first barrier is the need for funds to carry out additional projects. EVN has been highly successful in obtaining World Bank and other funds for necessary expansion and will continue to use these resources. It has also allowed IPPs to enter the market allowing it to use available funds for more generation projects.

The second barrier is the rate at which a competitive market is being developed. The present timetable sees a partly competitive electricity market by 2010. The efficiency improvement due to the market could be brought forward by a number of years with consequent improvement in performance and greenhouse abatement.

8.6 Government Initiatives

Through EVN and Vinacoal the Viet Namese government has a sound plan for the orderly improvement of the power system to meet the needs of the Viet Namese people over the next 20 years with respect to energy and electricity. Ownership of facilities has been relaxed to allow IPPs to operate and assist the government program to provide an adequate energy supply.

8.6.1 Necessary Policies

A timing change to government policy is necessary to bring forward the transition to a competitive electricity market. As a contribution to this the government has recently announced that it will allow IPPs to sell directly to large customers.

The present energy conservation policy for industry needs to be extended to the domestic and commercial sectors.

8.6.2 Action Plan

The Power Development Plan resolved by the government is an ambitious initiative to bring the economy from an agricultural one to an industrial state using major electricity generation initiatives. At the same time the energy mix selected has the effect of improving the greenhouse abatement over the planned time period. It is being implemented effectively.

However, there are some simple changes that could enhance this plan set out below. Most of these initiatives can be activated at little incremental cost to result in a more efficient program that combines high efficiency with greenhouse abatement.

- Recognise the capacity improvement due to transmission augmentation;

- Bring forward the transition to a competitive electricity market;

- Change the technology for new coal-fired plant from subcritical to supercritical design and then to integrated gasification combined-cycle technology;

- Refurbish older coal and hydro power stations and change open-cycle gas to combined-cycle;

- Bring consideration of nuclear plant forward.

These proposals could be applied to the present Power Development Plan with the following potential performance improvements and consequent improvement in greenhouse abatement. It is noted that a recent paper by Balce suggested a lower rate of development. This document has concentrated on the PDP and offered improvements on that basis which can be carried out notwithstanding modifications to the overall plan.

In 2000, a total of 26,600 GWhr was generated. The main sources of generation were hydro with a share of 59%, gas with a share of 30% and a greenhouse gas release of about 0.6 t CO_2/MWhr, and coal with a share of 11% and a greenhouse gas release of about 0.9 t CO_2/MWhr. This was therefore equivalent to an overall release of about 0.3 t CO_2/MWhr. For 26,600 GWhr this was equivalent to about 7,980,000 t CO_2 per annum.

Assuming the same energy resource mix shares in 2010 a modified greenhouse gas release can be calculated. Hydro plant would not contribute. Gas would reduce greenhouse gas release from 0.6 to 0.5 t CO_2/MWhr because of refurbishing some older plant to combined-cycle operation. Coal would have reduced from 0.9 to 0.8 t CO_2/MWhr because of changes from subcritical to supercritical and IGCC. The overall equivalent greenhouse gas release would have been about 0.24 t CO_2/MWhr.

Correcting this for improvement in transmission loss of 4% and competition improvement of 1%, this becomes about 0.23 t CO_2/MWhr. However in 2010 the 2001 PDP expects generation of 70,000 GWhr resulting in about 21 million t CO_2 per annum. The potential saving in greenhouse release over the present plan would be about 5 million t CO_2 per annum.

The savings from instituting a domestic energy conservation plan would also improve abatement.

8.7 Appendices

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8.7.2 Acknowledgments

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8.7.3 Notes

1 The most recent data has been used as far as possible. Where this data is more than two years old it is followed by the year in brackets.
2 All projections are shown at one or at most two significant figures indicating the level of uncertainty with predicting further into an uncertain future.

8.8 Glossary

APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of South-East Asian Nations
BOT	Build Own Transfer
CDM	Clean Development Mechanism
CEPSI	Conference of the Electricity Power Industry
CNA	CDM National Authority
CO_2	Carbon Dioxide
EDFI	EDF International
EVN	Electricity of Viet Nam
GDP	Gross Domestic Product
GMS	Greater Mekong Subregion
GWhr	Giga Watt Hour
HMS	Hydrometeorological Service
IGCC	Integrated Gasification Combined-Cycle
IPP	Independent Power Producer
kWhr	Kilo Watt Hour
MECO	Mekong Energy Company
MONRE	Ministry of Natural Resources and Environment
MW	Mega Watt
NOCCOP	National Office on Climate Change and Ozone Protection
NSS	National Strategy Study
PDP	Power Development Plan 2001
TEPCI	TEPCI International
TILF	Trade and Investment Liberalisation and Facilitation
UNFCCC	United Nations Convention on Climate Change
UNIDO	United Nations Industrial Development Organisation
VNCCCT	Viet Nam Climate Change Country Team

9. DISCUSSION

9.1 Description of Phases I and II of this Project

Phase I of this project identified options to reduce CO_2 emissions from existing and future fossil fuel power plants in the APEC region. A total of 19 scenarios were identified, classed into 4 categories, as follows :

- Combustion, steam cycle and operating and maintenance upgrades;
- Co-firing and switching to lower carbon fuels;
- Repowering using more efficient technology;
- Combined heat and power generation.

In Phase I a fairly broad-brushed approach was taken to investigate the potential of applying all of the categories to the APEC region as a whole. Phase II of the project, (the findings being presented in this report), has taken a more specific approach, looking at practical application of specific examples of projects that have resulted in lower emissions as well as highlighting the approaches and action plans that have been adopted by two APEC economies to reduce CO_2 emissions. Phase II has also briefly reviewed and described the key enabling factors for the reduction of CO_2 emissions in the APEC region.

9.2 Case Study Findings

Eleven case studies have been identified of specific examples of projects that have been successfully applied in the APEC region to reduce CO_2 emissions in the power generation sector. The case studies cover all of the four categories presented above. For each case study the project is described, the actual CO_2 abatement is calculated and the capital and overall abatement costs are determined and the key factors that lead to the project being implemented are identified. The major findings from this review are described below :

9.2.1 CO_2 Abatement

The repowering options gave the largest CO_2 abatement, which also gave the largest decrease in greenhouse intensity (up to 55%). Repowering allows a large increase in efficiency through, for example, the use of high efficiency combined-cycle technology whilst using existing power plant infrastructure (reducing construction time and costs). Repowering also allows the option to switch to a lower greenhouse intensive fuel.

Power station upgrades and refurbishment gave up to a 12% reduction in greenhouse intensity and had modest abatement compared with repowering. Combustion of biomass in the Liddell and Bayswater Power Stations (Macquarie Power) reduced the overall greenhouse intensity only slightly (0.4%) and gave only a modest CO_2 abatement due to the relatively small amount of biomass combusted in the larger Bayswater Power Station and also due to a limit on the amount of biomass that can be supplied into the Liddell Power Station (due to milling capacity).

9.2.2 Cost of Abatement

Of the nine case studies where an abatement cost could be calculated, eight indicated an abatement benefit from the upgrade rather than a cost. This is indicative of the fact that the upgrades were economic in their own right, and many would have been unlikely to have occurred had they not been. Abatement benefit ranged from US$ 0.7 to 33.2 / t CO_2. The exception was Wabash where the capital and operating costs exceeded any financial benefit from the increased plant efficiency, giving an abatement cost of US$ 249 / t CO_2.

The highest abatement benefit came from three of the repowering case studies (Astoria, Chita and Senoko Power Stations) as a result of large increases in efficiency and large fuel cost savings for the power generated. Comparison of the supercritical Yonghung Power Station with an equivalent subcritical plant indicted an abatement cost benefit in favour of the supercritical plant.

All of the three refurbishing case studies gave an abatement benefit from US$ 0.7 to 5.4 / t CO_2.

9.2.3 Cost of Additional Capacity

All of the seven case studies that involved either an upgrade or repowering of a power plant resulted in an increase in power generation. A key enabling factor is that upgrading or repowering of power plant is cost effective. For the plant upgrading case studies, the cost of the additional power generation is significantly lower than the cost of installing new plant (Malaya upgrade US$ 727 / kW and Banshan US$ 350 / kW).

Similarly for three of the four repowering case studies the installed cost for the additional generation capacity was under US$ 800 / kW, taking advantage of the existing infrastructure in the power plant. The exception being for Wabash, a first-of-a-kind gasification repowering project.

9.2.4 Effect of Green Credits / Government Purchase of Credits

Liddell Power Station received US$ 3.25 million towards the replacement of the LP cylinders on four units from the Australian Government as part of the Greenhouse Gas Abatement Program (GGAP) scheme. The funding turned an uneconomic project (which may not have gone ahead without the funding) into an economic one, enabling 300,000 t of CO_2 to be abated annually.

Macquarie Generation creates Renewable Energy Certificates (RECs) through the Australian Government's Mandatory Renewable Energy Target (MRET) program for power generation from combustion of biomass in its Liddell and Bayswater Power Stations. RECs can be traded for about US$ 19 / MWhr. This dramatically increases the financial viability of supplementary firing of biomass for power generation, bringing in an additional revenue stream of US$ 1.6 million per year for Macquarie Generation.

9.3 Summary of Case Study Findings

The key plant performance criteria (before and after implementing the plant improvements) for the Case Studies are summarised in Table 20.

Table 20 : Summary of Case Study Findings

Case Study	GI Before (kg CO_2 / MWhr)	GI After (kg CO_2 / MWhr)	% Cut in GI	CO_2 Change (ktpa)[1]	CO_2 Saving (ktpa)[2]	MW Before	MW After	Cost of Additional Capacity (US$/kW)	Efficiency Before (% HHV)	Efficiency After (%HHV)	Abatement Cost US$ / t CO_2
Power Station Upgrade											
Malaya Power Station	851	748	12%	+842	470	430	650	727	30.9	35.1	-5.4
Banshan Power Station	1,211	1,066	12%	-45	120	125	135	350	33.9	38.5	-4.8
Liddell Power Station	969	941	3%	0	300	2,000	2,060	780	32.7	33.7	-0.7
Co-Fire / Fuel Switch											
Macquarie Generation	917	913	0.4%	-100	100	4,640	4,640	n/a	34.5	34.5	-17.4
Repowering											
Astoria Generating Station	826	368	55%	-2,800	6,500	1,254	1,816	631 / 2,007[3]	34.5	50.0	-18.4
Chita Power Station	557	465	17%	+725	2,885	3,550	4,474	390	34.0	40.7	-33.2
Senoko Power	669	412	38%	0	1,045	524	850	788	28.3	45.9	-27.0
Yonghung	890	788	11%	-1,219	1,219	n/a	1,600	1,562	38.5	43.5	-11.8
Wabash River Repowering	953	786	18%	+736	268	90	262	1,590 / 2,422[3]	33.0	40.0	249
Combined Heat and Power											
Map Ta Phut	841	796	5%	-183	183	n/a	514	1,058	40.7	43.0	

Notes

1 - Annual change in CO_2 emissions due to implementing the plant improvements (+ve number indicating an increase in emissions, -ve number indicating a decrease).
2 - Calculated CO_2 savings based on the annual power generation of the improved plant and the difference in greenhouse intensity between the old and upgraded plants.
3 - Two costs of additional installed capacity presented, the first assumes that the plant is essentially a new installation and the second calculates the cost based on the increase in power generation over the existing installed capacity.

9.4 Enabling Factors

9.4.1 Role of Government

The role of Government is considered to be pivotal in setting the regulatory and economic environment that provide the necessary drivers for achieving the desired reduction in CO_2 emissions. The means that Governments have at their disposal are many and varied, as has been demonstrated in many of the case studies, from implementation of national schemes and policies to providing assistance to specific projects.

- Foreign investment in power generation in the Philippines was facilitated by the sale of generating assets that were subsequently refurbished, reducing emissions (such as the Malaya Thermal Power Station);
- For Banshan Power Station refurbishment occurred as a result of an Australia - China co-operative project;
- Replacement of the LP cylinders at the Liddell Power Station was enabled through the Australian Government's Greenhouse Gas Abatement Scheme Program (GGAP) that paid for just under 10% of the capital cost of the upgrade;
- For Lanzhou City, Local and State Governments policies opened the way for foreign investment in new low emission power generation facilities as well as the development of large infrastructure projects to supply natural gas and centralise district heating;
- For Macquarie Power, the Australian Government's Mandatory Renewable Energy Target (MRET) made biomass co-firing economically viable through the creation of tradable Renewable Energy Certificates (RECs);
- For Astoria, the New York State Government has introduced policy to promote development of new efficient generating capacity to maintain pace with demand;
- The Japanese Government promotes energy conservation and places heavy restrictions on land use for new power generation facilities, making repowering of the Chita Thermal Power Station attractive;
- The Singapore Government actively promotes energy conservation in the power sector through fiscal and non-fiscal policies, enabling the conversion of the Senoko Power Station from open- to combined-cycle operation;
- The Korean Government has developed a number of energy policy initiatives recognising the limited indigenous energy resources and to develop world-class technology in both efficiency and environmental performance, resulting in the development of the Yonghung supercritical power plant;
- The United States Government, through the Department of Energy's (DOE) Clean Coal Technology program funded 50% of the capital and operating costs of the Wabash coal gasification repowering project through the demonstration phase;
- The Thai Government has been active in ensuring the development of efficient power generation plant including the Map Ta Phut Cogeneration facility.

9.4.2 Development of Clean Coal Technology (CCT)

Many Governments are coming to the view that active development of advanced clean coal technologies is a major enabling factor in mitigating greenhouse gas emissions in the medium to long term. This will be a major focus in the years to come, particularly given the potential of zero CO_2 emissions using CO_2 capture and sequestration friendly technologies.

The maturing of supercritical technology has reached the stage where capital cost penalties over subcritical plants are diminishing, and as was seen for the Yonghung case study, the costs are more than compensated for by reduced fuel costs (see Section 4.9). The challenge will be to achieve similar outcomes for other CCTs being developed through continual reduction in capital and operating costs, increase in plant availability and performance.

Implementation of CCTs is likely to require incentives (eg carbon tax or legislation to mandate new technology installation) to overcome the barriers to implementation. The enabling of access to such technologies for developing economies will be of considerable importance.

9.5 Economy Reviews

Two APEC economies (Malaysia and Viet Nam) were selected to highlight the approaches that have been adopted to reduce CO_2 emissions in these very different economies.

9.5.1 Malaysia

Malaysia has a comprehensive set of energy policies and bodies in place to meet its strategic goals. Malaysia is a strong participant in international initiatives on climate change as is a non-Annex 1 Nation under the United Nations Framework Convention on Climate Change (UNFCCC). Malaysia has outlined specific processes by which greenhouse gas emissions will be minimised from the energy sector through implementation of efficient power generation and transmission, demand side management and energy efficiency initiatives and use of biomass and other renewable fuels (5% of total power generation target for 2005).

The majority of installed capacity in Malaysia is gas-fired. A significant number of open-cycle plants are being converted to combined-cycle. Malaysia is to also refurbish older subcritical coal-fired power stations. Malaysia's Fuel Depletion Policy requires all future coal-fired power generation plant must use clean coal technology.

The power generation market was opened to competition in 1994 and it is expected that as the competitive market grows, further efficiency gains can be expected.

9.5.2 Viet Nam

Viet Nam has ratified the United Nations Framework Convention on Climate Change (UNFCCC) and is a signatory to the Kyoto Protocol as a non-Annex 1 economy.

Hydro power comprises 60% of Viet Nam's current generation capacity, followed by gas turbine 14%, coal 10% and oil 4%. Domestic demand is forecast to rise by 13 - 15% until 2010 through construction of new hydro (4,000 MW), gas-fired (6,500 MW) and coal-fired

(3,000 MW) power generation plant. This growth is being effectively managed through a comprehensive and long-term Power Development Plan.

The continued development of hydro power and gas turbine combined-cycle for the new gas-fired plant will ensure that greenhouse gas emissions will be minimised. Viet Nam has a major energy conservation policy for major industry and has plans to reduce system transmission losses by 4%. Opportunities exist for the use of supercritical coal-fired power plant (over the proposed subcritical units) to further minimise emissions.

Reform of Viet Nam's power sector started in 1995 when the economy began to develop a market economy and allowing independent power producers to operate in the market, which is expected to have a positive impact on generating efficiency.

9.6 Glossary

APEC	Asia-Pacific Economic Cooperation
CCT	Clean Coal Technology
CO_2	Carbon Dioxide
DOE	Department of Energy
GGAP	Greenhouse Gas Abatement Program
GI	Greenhouse Intensity
HHV	Higher Heating Value
ktpa	Kilo Tonnes per Annum
kW	Kilo Watt
kWhr	Kilo Watt Hour
LP	Low Pressure
MRET	Mandatory Renewable Energy Target
MW	Mega Watt
MWhr	Mega Watt Hour
RECs	Renewable Energy Certificates
UNFCCC	United Nations Framework Convention on Climate Change

10. CONCLUSIONS AND RECOMMENDATIONS

10.1 Conclusions

The conclusions from this study are as follows :

10.1.1 Case Studies

- There are many examples of projects that have been implemented in the APEC region (only a fraction of which have been presented in this report) that have resulted in a reduction in CO_2 emissions;
- For the majority of the case studies investigated, the projects were implemented as a result of being economically viable in their own right (an important enabling factor);
- For two projects (Liddell Power Station upgrade of LP turbine and Macquarie Generation biomass co-firing), economical viability was enabled through Government schemes aimed at reducing greenhouse gas emissions;
- The repowering case studies gave a very high reduction in greenhouse intensity (up to 55%) as well as enabling large increases in power generation (for a similar fuel demand), with the use of existing infrastructure reducing costs and implementation time;
- Refurbishment of older thermal power stations gave up to a 12% reduction in greenhouse intensity as well as significant increases in power generation (at a unit cost significantly lower than that of new power plant);
- Most case studies indicated there was an CO_2 abatement benefit from implementing the project, rather than an abatement cost (taking into account changes in operating cost and revenue from power generation and the annualised capital cost for the project);
- Governments played an important role in every case study in enabling the project to go ahead.

10.1.2 Economy Reviews

- The Governments of Viet Nam and Malaysia have recognised the need the CO_2 emission control and are active participants in supporting international initiatives on climate change;
- Both economies have active plans for meeting projected energy demand in an manner that minimises CO_2 emissions;
- Market reform in Viet Nam and Malaysia is expected (through competitive pressures) to promote efficient generation practices;
- The entry of IPP's into the markets has allowed capital inflow. Attracting equity (including foreign investment) into power projects will be a key factor in enabling selection of efficient generation technology;
- Both economies have programs for demand side management and energy efficiency initiatives, reduction of transmission losses, the use of high efficiency technology for most new power plant, refurbishment of older thermal units and initiatives for the use of renewable energy resources applicable to the particular economy (eg hydro and biomass);

10.2 Recommendations

It is recommended that further work be undertaken to facilitate implementation of effective CO_2 emission reduction strategies for the power generation sector in the APEC region, as follows :

- Implementation of nearer term measures to reduce CO_2 emissions from the power generation sector (as outlined by the 4 basic categories developed as part of Phase I and as demonstrated in Phase II) will be a major focus of overall mitigation plans for APEC economies and the region as a whole. It is recommended that the key stakeholders (senior government officials, power industry representatives, technology suppliers and financiers) be brought together to encourage and facilitate adoption of such measures in a suitably considered forum. This could include presenting of a number of case studies (including lessons learned) and highlighting means of moving projects forward;

- With projected growth of fossil fuel demand for power generation in the APEC region, it is essential that this growth is achieved in a clean and climate friendly way. Zero Emission Technologies (ZETs) are being developed throughout the world, and initiatives to facilitate international collaboration and cooperation in the APEC region on the development and use of ZETs are recommended;

- Further, even more specific work is recommended to investigate opportunities for the implementation of the 4 basic categories for reducing CO_2 emissions within one APEC economy by outlining examining specific and practical opportunities within existing generating facilities. Greatest benefit would come from choosing an economy that has a high growth demand for power.

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