ASIA PACIFIC ENERGY RESEARCH CENTRE

MAKING THE CLEAN DEVELOPMENT MECHANISM WORK

WITH SOME CASE STUDIES IN THE APEC REGION

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FOREWORD

I am pleased to present the final report of the study, "Making The Clean Development Mechanism Work: with Case Studies in the APEC Region." The study is one of five new research projects commenced in the year 2000.

The objective of the study was to investigate some of the key issues likely to influence the success of the CDM in promoting clean development in the APEC region, and to calculate the likely return on investment and value of carbon credits for a number of specific electricity supply investment options in selected APEC economies.

The principal findings of the study are highlighted in the executive summary of this report, and suggest that if the CDM is going to reach its potential to contribute significantly to carbon emissions reductions in developing economies, the proposed rules governing its operation will need to be reassessed.

This report is published by APERC as an independent study and does not necessarily reflect the views or policies of the APEC Energy Working Group or of individual member economies.

Finally, I would like to thank all those who have been involved in this major and I believe successful exercise including the staff at the Centre, both professional and administrative, the experts who have helped us through our conferences and workshops, and many others who have provided interesting and useful comments. I hope this report will be useful to a wide audience.

Keiichi Yokobori
President
Asia Pacific Energy Research Centre

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We would like to thank all of those who worked so hard on the project. The development of this report could not have been accomplished without the contributions of many individuals.

We wish to express our appreciation to the APERC Conference and Workshop participants who met with us and provided invaluable insights into the issues raised in the draft report.

We also thank all members of the APEC Energy Working Group (EWG), APEC Expert Group on Energy Data and Analysis (EGEDA), APERC Advisory Board and other government officials for their stimulating comments and assistance with the study. Our thanks go also to the APERC administrative staff for their help in administration and publication of this report.

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ADB	Asian Development Bank
AIJ	Activities Implemented Jointly
AIT	Asian Institute of Technology
APEC	Asia-Pacific Economic Co-operation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
BAU	Business-as-usual
CER	Certified Emission Reductions
CDM	Clean Development Mechanism
CCGT	Combined Cycle Gas Turbine
CH_4	Methane
CNG	Compressed natural gas
CO_2	Carbon dioxide
EDMC	Energy Data and Modelling Centre (Japan)
EIA	Energy Information Administration (USA)
ERU	Emissions Reduction Unit
EWG	Energy Working Group (APEC)
FCCC	Framework Convention on Climate Change
FGD	Flue-gas de-sulphurisation
GEF	Global Environmental Fund
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatt (10^9 Watt)
GWh	Gigawatt hour (one million kilowatt hours)
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
JI	Joint Implementation
kcal	Kilo calories
kW	Kilowatt (= 1,000 watt)
kWh	Kilowatt hour (= 1,000 watt hour)
ktoe	Kilo tonnes of oil equivalent
LBNL	Lawrence Berkeley National Laboratory
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LRMC	Long run marginal cost
MtC	Million tonnes of carbon
Mtce	Million tonnes of standard coal equival
Mtoe	Million tonnes of oil equivalent
MW	Megawatt (= 1,000 kilowatt)
MWh	Megawatt hour (= 1,000 kilowatt hour)
NGCC	Natural gas combined cycle
NO_X	Nitrogen oxides
OECD	Organisation for Economic Cooperation and Development
OPEC	Organisation of Petroleum Exporting Countries
PPP	Purchasing Power Parity
R&D	Research and Development
SO_X	Sulphur oxides
SRMC	Short run marginal cost

TPEC	Total primary energy consumption (supply)
TWh	Terawatt hour
UN	United Nations
US	United States (of America)
US DOE	United States Department of Energy

PREFACE

The APEC Energy Working Group (EWG) does not, in general, get involved in climate change issues, but instead stays focused on energy sector investment and trade facilitation in the Asia Pacific region. So this project is a little outside of the normal scope of study considered by the Asia Pacific Energy Research Centre.

However, the Clean Development Mechanism (CDM) has the potential to be an important tool for encouraging private sector energy investment in the developing economies in the Asia Pacific region. Because of this, investigation of the potential of CDM as an energy sector "technology transfer" tool is well within the scope of EWG interests.

PROJECT OBJECTIVES

- To investigate the potential of the Clean Development Mechanism to act as a valuable technology transfer tool and aid to energy sector investment in the Asia Pacific region.
- To carry out economic/environmental feasibility studies on some potential electricity supply projects, taking into account the financial viability and CO_2 emission reduction potential.
- Identify the practical problems and barriers to effective implementation of CDM projects, as well as research benefits.

RATIONALE FOR THE PROJECT

This project supports the APEC 14 Non-Binding Energy Principles, in particular Article 8: "*Promote the adoption of policies to facilitate the transfer of efficient and environmentally sound energy technologies on a commercial and non-discriminatory basis.*" and Article 14: "*Cooperate, to the extent consistent with each economy's development needs, in the joint implementation of projects to reduce greenhouse gas emissions consistent with the Climate Change Convention.*"

At the Third APEC Ministers meeting in Okinawa, paragraph 19 in the Ministers Declaration stated that: "*Recognizing the necessity to minimize the adverse environmental impact of new energy infrastructure development, Ministers endorsed the Recommended Work Program on Environmentally Sound Energy Infrastructure in APEC Member Economies.*" They agreed that the work program would provide impetus to the application of environmental policy practices that are predictable, transparent and consistent. Ministers noted that such practices would facilitate energy investment while allowing investors flexibility in meeting environmental objectives, and charged the Energy Working Group to develop practical and effective means of implementation.

Paragraph 25 also stated that: "*Ministers stressed the importance of promoting energy research and development, commercial and economic transfer of environmentally sound technologies, and continuing cost-reduction in the introduction of these new technologies, with the direct participation of the business sector.*"

EXECUTIVE SUMMARY

IS CLIMATE CHANGE REAL?

In its 1995 second assessment report, the Intergovernmental Panel on Climate Change stated that: "the balance of evidence, from changes in global mean surface air temperature and from changes in geographical, seasonal and vertical patterns of atmospheric temperature, suggests a discernable human influence on global climate." In a February 2001 pre-release of the third assessment report, the panel has warned that warming over the next century would increase more than originally thought, from a minimum of 1.5 °C to 5.8 °C.

KYOTO AND THE FLEXIBILITY MECHANISMS

The Kyoto Protocol adopted at COP3 provided for the possibility of legally binding commitments to reduce global greenhouse gas emissions. For Annex I Parties, a 5 percent reduction from 1990 levels was set as the target for the first commitment period (2008-2012). To assist in meeting this target, the Kyoto Protocol made provision for a number of "flexibility mechanisms," including emissions trading, Joint Implementation (JI) and the Clean Development Mechanism (CDM).

The CDM concept is defined in Article 12 of the Kyoto Protocol, and sets itself apart from the other flexibility mechanisms in that it is specifically oriented to encouraging Annex I investment (through clean technology transfer) in developing economies, but at the same time allowing the investor to reap benefits through Certified Emission Reduction (CER) credits used to contribute to compliance with the Kyoto Protocol.

UNDERSTANDING THE CDM RULES

After the smoke had cleared, and the Kyoto Protocol was adopted, some commentators argued that this had been made possible, in large part, because of the inclusion of "Flexibility Mechanisms," which could reduce the cost of complying with emissions targets. Further, it was argued that although the flexibility mechanisms were of central importance to the Protocol, they are ambiguously defined - and much work would be needed to clarify how they will actually work.

One of the key factors being negotiated to govern the acceptance of investments as CDM projects is the concept of "additionality." Climate change negotiators have argued that additionality is central to the successful operation and integrity of the Clean Development Mechanism because it will be the main way in which genuine CDM investments can be differentiated from "business-as-usual" investments.

The term "*environmental additionality*" has been coined to refer to the requirement that a CDM project must generate emissions reductions additional to any that would otherwise occur in the absence of the project.

Emission baselines for JI and CDM are the agreed methodology to quantify "what would have happened" in the absence of these projects

A baseline, even when determined on the basis of accurate historical data, is a hypothetical construct when projecting future emissions behaviour, so is open to argument if the future is not a predictable projection of the past (as is often the case).

Regardless of the difficulty of predicting the future on the basis of the past, it is generally agreed that a baseline must be: environmentally credible; transparent and verifiable by a third party; simple and inexpensive to develop; and provide a reasonable level of crediting certainty for investors.

Although in principle, establishment of baselines would appear to be a relatively straightforward aspect of the Kyoto flexibility mechanisms, the significant debate concerning how this should be achieved indicates that baseline setting could represent a substantial hurdle to their implementation.

CREATING A SOUND CDM INVESTMENT ENVIRONMENT

For the CDM to reach its potential, it must encourage large-scale transfers of capital and technology from developed to developing economies. Anything less, and the mechanism will have a negligible impact on emissions targets and on burgeoning GHG emissions worldwide. Although the idea of large-scale transfers of capital will meet resistance from some quarters, this is already happening in an increasingly globalised world, and the benefits of clean technology transfers are two-fold: they promote economic growth in the developing world, and they reduce the overall greenhouse gas emission burden by reducing the impact of that growth.

Such investment will also allow firms in the developed world to meet their GHG emissions targets at least cost. Recent research demonstrates quite dramatically that marginal abatement costs in high-cost, energy efficient economies like Japan are many times higher than for an economy like China, where large efficiency gains (or GHG emissions reductions) are possible at relatively low marginal abatement costs.

A key issue for potential CDM investors will be the rate of return on the investment. This issue is controversial, because some UNFCCC negotiators are arguing that CDM projects pass an *investment* additionality test - to demonstrate that the project would not have been implemented without the economic contribution from the carbon credits. It takes very little contemplation to see that such a test could easily become the single biggest hurdle to the successful implementation of the CDM scheme.

This report includes the results of some preliminary modelling exercises that show quite clearly that many of the more desirable technology transfer options in the electricity supply sector - such as installation of wind farms to replace planned coal-fired power plants - would require very high carbon credit prices to be attractive to private investors. On the other hand, a CCGT plant replacing a planned coal plant would be a financially attractive proposition in many cases, but would in all probability stumble over the investment additionality test.

ELECTRICITY SUPPLY - A PRIME CDM TARGET

The focus of this study is the electricity supply industry. This is only one potential area for CDM investment, but it is an attractive sector for a number of reasons.

According to a recent IEA World Energy Outlook, world CO_2 emissions from the electricity sector represent over one third of world annual energy-related CO_2 emissions and are projected to increase at an annual rate of 2.7 percent between 1995 and 2020.

The generation of electricity, as one of the major contributors to localised and regional pollution, and to growth in GHG emissions, tends to be more amenable to emission control than the transportation and other sectors because of the limited number of localised point sources, the availability of modern technologies to improve plant efficiency and hence emissions, and the availability of economical alternative low carbon (or even zero-carbon) fuels.

One of the most carbon intensive of fuels is coal, and it is widely used for power generation. While the market share of coal has fallen, global demand has increased greatly due to its use in electricity generation, cement and steel production. Today, coal contributes about 27 percent of global primary energy demand, second only to oil. Coal is used to produce 37 percent of the world's electricity, and approximately 16 percent of global hard coal production is used to produce 70 percent of total global steel production.

A logical alternative to high carbon fuels such as coal and fuel oil is natural gas. Modern combined cycle gas turbines are reaching high levels of thermal efficiency (approaching 60 percent) and gas consumption for power generation in the APEC region is rising fast where it is readily available. Gas consumption for power generation in the APEC region is projected to more than double from 1995 to 2010, contributing 48 percent to the increase in gas demand. There are also other advanced technologies that might provide even more efficient natural gas conversion and end use in the future. Fuel cells, mini and micro turbines, conversion of gas to liquids and production of hydrogen with carbon removal and storage are all options likely to diffuse into the marketplace in the near to mid-term future.

Two power generation fuels that might have been expected to contribute, in an important way globally, to the mitigation of greenhouse gas emissions from energy consumption are large-scale hydro and nuclear. However, because these technologies have other environmental, social and health impacts, widespread public resistance to further development - especially nuclear power development - will likely prevent them from making a significant contribution to greenhouse gas mitigation.

Standard projections indicate that renewable energy consumption will increase quite modestly in APEC economies over the next decade or two. The 1998 APERC Demand and Supply forecast predicts a rise of 35 percent (2.0 percent pa) in renewables as a component of primary energy supply - from 142 Mtoe in 1995 to 193 Mtoe in 2010. In real terms, this is a very small amount of energy when compared with regional requirements. Such modest increases in investment in new renewable energy resources would make virtually no significant contribution to greenhouse emission reduction. Only a large-scale shift in policy thinking and investment patterns could achieve what some commentators consider possible.

ENERGY SUPPLY GROWTH AND CARBON INTENSITY IN ASIA

Asia is important to the climate change debate for a number of key reasons. Firstly, no other region of the world has demonstrated the same rates of sustained economic growth over the last two decades. From 1966 to 1990, the “Tigers” of East Asia (Singapore, South Korea, Chinese Taipei and Hong Kong China) showed growth in real income per person of more than 7 percent per year, compared with about 2 percent in the United States.

Although the total primary energy supply in some of these economies is small on a regional or global scale, this cannot be said for China, which is now second only to the US in this regard, and still has huge growth potential. The key points are that the region has rapidly expanding energy supply requirements and is on the whole attractive to investors looking for good returns at reasonably low risk to capital.

High rates of energy and transport sector growth have brought rapid increases in net carbon emissions, and with many Asian economies still undergoing rapid industrialisation, an opportunity exists for developed world political and industry leaders to influence the types of energy sector technologies that are installed over the next one or two decades. Because energy infrastructure is typically long-lived, choices made today have impacts well into the future. Of particular importance are the choice of fuel and associated technologies for power generation, and the infrastructure that must be put in place to support those choices.

This report looks in some detail at a number of economies that are potentially attractive from a CDM perspective: China, Malaysia, Indonesia, the Philippines and Thailand. In particular, historical and short-term future fuel requirements for power generation are considered, and the carbon intensity of the fuel mix calculated for each economy. By disaggregating power generation into individual fuels, it is possible to develop a sector-wide benchmark carbon intensity baseline for each economy.

CASE STUDIES

As well as the simulations reported in Chapter 4, this report includes three specific case studies for China, Indonesia and Thailand. In each case, a different project has been selected, in part to reflect the kind of economy-specific options that are available and also to reflect a range of potential electricity generation investment opportunities.

The first case study looks at a wind power project in China. The second case study looks at a 300 MW natural gas combined cycle power project in Java-Bali replacing a coal-fired plant of similar capacity. The third case study looks at a project in Thailand where biomass is used as supplemental fuel in a coal-fired power station.

MAKING THE CDM WORK

Making the Kyoto Protocol work will probably require a negotiated agreement that is much less stringent and ideologically pure than many hard-line environmentalists and some government negotiators will be happy with, and will certainly require a willingness to embrace innovative solutions. One thing is clear, in the long-term fight against global warming, we need every tool available.

Some experts have (rightly) argued that if we take carbon sequestration and market mechanisms out of the Kyoto equation, or bog them down with such overly restrictive rules that nobody uses them, then the ability to meet key environmental objectives such mitigation of greenhouse gas emissions will be severely limited.

It is the thesis of this report that the CDM rules as negotiated to date are already undesirably restrictive, and are in many respects unworkable, especially with respect to the concept of additionality, and also potentially with respect to baseline development.

Although one can realistically argue that projects must be able to prove that carbon emissions are being saved, and hence some form of reasonably rigorous control and monitoring process must exist, there is a fine line between those rules that are necessary to ensure the overall integrity of the mechanism and those which will reduce its uptake and hence effectiveness to the point where it is irrelevant.

One could argue that the whole concept of “additionality” is flawed and liable to create considerable difficulties for investors willing to embrace the CDM concept, but fighting a rear guard action with hard-liners arguing that their project has not passed the additionality test.

The problem is that in the real world, and in particular in the fast developing Asia-Pacific - a region investors are willing to do business in because the risks are reasonable and the legal and financial institutions are sufficiently robust and mature compared with other developing regions in the world - is that proving that a project would not have happened otherwise will be a very difficult thing to do.

One of the more cost effective investments, and one that would have a substantial carbon mitigation potential while at the same time contributing to local economic development needs, is the construction of a CCGT power station instead of a coal-fired one. Of course, where gas is available in Asia, many such power stations have already been built. However, such an investment should qualify as a CDM project where it can be demonstrated that the new gas-fired power station is replacing a planned coal plant. This is of key importance because Asian members of APEC are growing economically at 6 - 8 percent per annum, meaning they will be looking to duplicate their entire electricity supply systems in 10 to 15 years. Much of this planned development is based on installation of coal-fired power plants, because imported steam coal is very competitive, and energy security policies favour fuel diversification.

Projects based on renewable energy or new technologies, by contrast, would have an easier time proving environmental additionality, but may stumble as a result of high up-front capital costs and the reluctance of lending institutions to offer favourable terms, as well as a host of other hurdles that raise the transaction costs for these types of investments. In fact, a very good argument could be sustained that these types of projects should by definition have already proved additionality - hence relieving them of the burden of proof and allowing them to advance on their economic and sustainability merits alone.

Another area where investment should be encouraged is in end-use eeficiency improvements. This study did not look specifically at demand-side energy opportunities, but where such opportucities can be identified, and make commercial sense, they should, like renewable investments, suffer lower hurdles as CDM projects.

CHAPTER 1

INTRODUCTION

IS CLIMATE CHANGE REAL?

For some time it has been widely accepted that the rise in global atmospheric concentrations of carbon dioxide and other greenhouse gases (GHG) (particularly methane and nitrous oxide) over the last century have been caused primarily by human activity, such as burning of fossil fuels, and land-use change and agriculture. Additionally, scientists report a discernable global warming trend over the 20th century, and believe there is a direct relationship between this trend and the rise in anthropogenic emissions of greenhouse gases. In its 1995 report, the IPCC stated that: "the balance of evidence, from changes in global mean surface air temperature and from changes in geographical, seasonal and vertical patterns of atmospheric temperature, suggests a discernable human influence on global climate" [IPCC, 1995]. In a February 2001 pre-release of the third assessment report, the panel has warned that warming over the next century would increase more than originally thought, from a minimum of 1.5 °C to 5.8 °C [IPCC, 2001].

More recently, even a cursory perusal of the media literature on the subject of climate change should leave the enquirer in no doubt that the climate of the world is in fact undergoing significant change, and global climate warming appears to be happening:

- "The Earth's ice cover is melting in more places and at higher rates than at any time since record keeping began. Reports from around the world compiled by the Worldwatch Institute show that global ice melting accelerated during the 1990s- which was also the warmest decade on record" [Worldwatch, 2000].

- "Shorter lake and river ice seasons confirm global warming.....an international team of researchers concluded that temperatures have risen steadily for at least 150 years" [CNN, 2000a].

- "Coal-burning power plants, diesel-burning cars and buses, dung burnt for heating and cooking - all are sources of soot, and all combine to create a hazy concoction that reduces cloud cover and enhances global warming [CNN, 2000b].

- "Polar icecap melted for first time in human history…satellite studies have shown that the ice pack is more than 40 percent thinner than it was 50 years ago." [The Japan Times, August 21, 2000].

In his inaugural address to the sixth Conference of the Parties to the United Nations Framework Convention on Climate Change (COP6) meeting on 13 November 2000, Robert Watson, Chair of the Intergovernmental Panel on Climate Change (IPCC) stated that: "the Earth has warmed by between 0.4 and 0.8 degrees centigrade over the last century, with land areas warming more than the oceans, and with the last two decades being the hottest this century. Indeed, the three warmest years during the last one hundred years have all occurred in the 1990s and the twelve warmest years during the last one hundred years have all occurred since 1983. In addition, there is evidence that precipitation patterns are changing, that sea level is increasing, that glaciers are retreating world-wide, that Artic sea ice is thinning, and that the incidence of extreme weather events is increasing in some parts of the world" [Watson, 2000].

The question of whether global warming is being driven by anthropogenic emissions of greenhouse gases, or whether this effect is swamped by a natural warming cycle may be largely irrelevant. At climate change meetings officials have tended to agree on the "precautionary principle" - if it can't be shown that anthropogenic emissions of greenhouse gases are not contributing to global warming, then we are obliged to act as if they are.

WHAT ARE WE DOING ABOUT IT?

At a conference held in Toronto in June 1988, and attended by both policy makers and scientists, a consensus was established that anthropogenic global warming was a real issue, and that coordinated global action was required to deal with it. The conference called for reductions in global emissions of carbon dioxide, a comprehensive global convention as a framework for protocols on the protection of the atmosphere, and establishment of a "World Atmosphere Fund" to be financed in part by a levy on fossil fuel consumption in industrialised economies.

On 11th December 1990, the 45th session of the UN General Assembly adopted a resolution to establish the United Nations Framework Convention on Climate Change (UNFCCC). At the United Nations Conference on Environment and Development held at Rio de Janeiro in June 1992 (the Earth Summit), the framework convention was presented for signature. It came into effect in March 1994.

The further series of international negotiations, which culminated finally in December 1997 in the Kyoto Protocol to the UNFCCC and still continue to hammer out the rules of the game, is now well-documented history (this history is discussed in more detail in the Appendix). With the failure of the 2000 COP6 meeting to reach agreement on the details for implementing the protocol, especially with regard to issues such as supplementarity (the degree to which emissions reductions must be met through domestic actions), carbon sinks (in particular the acceptance of existing forests as carbon sinks), and compliance (the penalties for not meeting country targets), it is unclear whether co-ordinated international action will occur in the near future.

This report is concerned not with the actual Kyoto Protocol and its eventual ratification by enough signatories to bring it into effect, but with the ability of practical market mechanisms - in particular the Clean Development Mechanism - to assist in the realisation of the dream of sustainable energy supply growth in developing Asia-Pacific economies, while at the same time contributing to the mitigation of greenhouse gas emission impacts.

CHAPTER 2

KYOTO & THE FLEXIBILITY MECHANISMS

INTRODUCTION

The Kyoto Protocol adopted at COP3 provided for (he possibility of legally binding commitments to reduce global greenhouse gas emissions. For Annex I Parties,[1] a 5 percent reduction from 1990 levels was set as the target for the first commitment period (2008-2012).[2] To assist in meeting this target, the Kyoto Protocol made provision for a number of "flexibility mechanisms," including emissions trading, Joint Implementation (JI) and the Clean Development Mechanism (CDM). For a more complete description of the history of climate change negotiations, please refer to Appendix II.

Emissions trading would work through market processes, whereas JI and CDM are project-based instruments. Under the JI scheme, parties investing in individual projects will obtain Emissions Reduction Units (ERUs). Under the CDM scheme, parties will be awarded Certified Emissions Reductions (CERs). Both ERUs and CERs will be generated from project activity in return for investors' technology or capital transfer.

The difference between JI and CDM is that a JI project is implemented between Annex I Parties, while a CDM project is implemented between Annex I Parties and Non-Annex I Parties. The Kyoto protocol states that the use of these three mechanisms "shall be supplemental to domestic action."[3]

EMISSIONS TRADING

The emissions trading scheme allows the creation of a market for carbon credits in which Annex B Parties may participate.[4] Parties that face high costs of compliance in meeting their target may buy ERUs on an international trading market, and in so doing may lower their overall costs of compliance. The UNFCCC negotiators from the nations that have promoted emissions trading point to the relative success of the US-based SO_2 emissions trading scheme, and argue that this scheme would be the overall least cost approach to global greenhouse gas abatement.

JOINT IMPLEMENTATION

The purpose of Joint Implementation (JI) is to assist Annex I Parties to meet their emissions reduction targets by transferring to or acquiring from other Annex I Parties emissions reductions generated from project implementation. Joint Implementation is considered a supplemental instrument to domestic action. The argument in favour of this scheme is that Annex I Parties may obtain ERUs at a lower cost through JI than through domestic action.

The rules covering JI are less specific about verification of ERUs than the rules from CDM. This is because reporting methodologies and reliability are considered to be better in developed than underdeveloped economies.

THE CLEAN DEVELOPMENT MECHANISM

The CDM concept is defined in Article 12 of the Kyoto Protocol, and sets itself apart from the other flexibility mechanisms in that it is specifically oriented to encouraging Annex I investment (through clean technology transfer) in developing economies, but at the same time allowing the investor to reap benefits through Certified Emission Reduction (CER) credits used to contribute to compliance with the Kyoto Protocol.

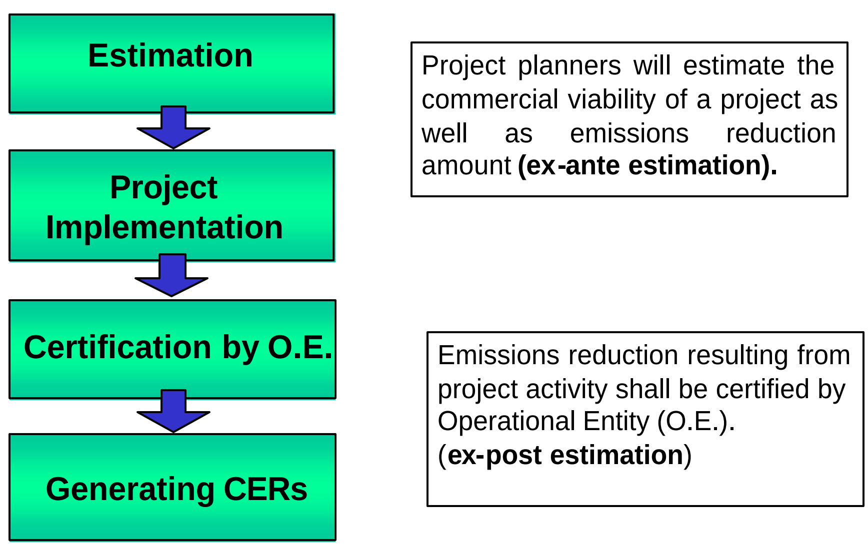
Article 12.2 of the Kyoto Protocol states that the objectives of the CDM are to: (1) assist the sustainable development of non-Annex I countries; and (2) assist Annex I countries in achieving compliance with their GHG mitigation targets. Article 12.7 of the Kyoto Protocol left the details on CDM modalities and procedures to be determined at the first session of the Conference of the Parties/Meeting of Parties (COP/MOP) after the Kyoto Protocol enters into force.

In order to ensure the CDM scheme operates successfully, Article 12.4 of the Kyoto Protocol allows for the creation of three overseeing bodies:

- The Conference of the Parties serving as the Meeting of the Parties (COP/MOP) will provide overall guidance.
- An Executive Board will supervise the mechanism.
- Independent auditors, called Operational Entities (OE) will certify the emissions reductions generated from project implementation.[5]

Figure 1 shows the flow of CDM project implementation. Before launching a project, the planners will estimate the quantity of emissions reduced by the project, as well as its commercial viability. The project will proceed, based on its environmental effectiveness and commercial viability, with the voluntary approval of each party involved. In both ex-ante and ex-post assessments, the baseline emissions trajectory must be determined as a standard against which the actual emissions reductions can be measured.

Figure 1 CDM project flow



CHAPTER 3

UNDERSTANDING THE CDM RULES

INTRODUCTION

After the smoke had cleared, and the Kyoto Protocol was adopted, some commentators argued that this had been made possible, in large part, because of the inclusion of "Flexibility Mechanisms," which could reduce the cost of complying with emissions targets [Kartha *et al*, 1999]. Further, it was argued that although the flexibility mechanisms were of central importance to the Protocol, they are ambiguously defined - "much work is needed to clarify how they will actually work" [Lazarus *et al*, 1999].

At the core of the workability of these mechanisms are some key rules governing how, or even whether, they will ultimately serve their designated purpose - to assist in practical ways, the implementation of the Kyoto Protocol.

ADDITIONALITY

Article 6 of the Kyoto Protocol [UNEP, 1998] states, in reference to the transfer of emission reduction units, that projects may be used to achieve this goal, provided "…any such project provides a reduction in emissions by sources, or an enhancement of removals by sinks, that is additional to any that would otherwise occur."

Climate change negotiators have argued that the concept of "additionality" is central to the successful operation and integrity of the Clean Development Mechanism. The term "environmental additionality" has been coined to refer to the requirement that a CDM project must generate emissions reductions additional to any that would otherwise occur in the absence of the project. As a test of environmental additionality, some national negotiators have suggested that *investment* additionality be proven - that the project would not have been implemented without the economic contribution from the CERs [Haites and Aslam, 2000].

Some economies have also proposed that investors demonstrate *financial* additionality - that financing is additional to both official development assistance and contributions to the Global Environment Facility. Other economies have proposed that investors demonstrate *technological* additionality - that the technology used is the best available for the circumstances.

BASELINES

Emission baselines for JI and CDM are the agreed methodology to quantify "what would have happened" in the absence of these projects. A baseline, even when determined on the basis of accurate historical data, is a hypothetical construct when projecting future emissions behaviour, so is open to argumentation if the future is not a predictable projection of the past (as is often the case).

Regardless of the difficulty of predicting the future on the basis of the past, it is generally agreed that a baseline must be:

- environmentally credible;

- transparent and verifiable by a third party;
- simple and inexpensive to develop; and
- provide a reasonable level of crediting certainty for investors.

Although in principle, establishment of baselines would appear to be a relatively straightforward aspect of the Kyoto flexibility mechanisms, the significant debate concerning how this should be achieved indicates that baseline setting could represent a substantial hurdle to their implementation.

The first consideration is whether a baseline will be "project-specific" and hence reconstructed from scratch for every new project ("bottom-up"), whether it should be aggregated to a sub-sector or sector level, or be a "hybrid" baseline somewhere between these levels [Ellis and Bosi, 1999].

The possibility also exists for baselines to be constructed at a national level, referred in the literature as "top-down." These are relevant to broad, economy-level policy setting objectives, but may be at too high a level of aggregation to be useful for calculating the emissions benefits of specific projects, especially where these may be focussed on improvements in the efficiency of existing plant, or technological improvements at a localised level. Of the AIJ projects contemplated to date, most have relied on project specific baselines to calculate emission benefits.

PROJECT SPECIFIC BASELINES

Such a baseline is established by using data, simulations and assumptions specific to a particular project. In AIJ pilot phase projects, baselines tended to be drawn up on a case-by-case basis, and consequently some experience with this methodology now exists.

Because AIJ and CDM are designed to work through actions by private investors to take advantage of emission reduction opportunities, the baselines investigated to date (through the Activities Implemented Jointly (AIJ) pilot phase) have tended to be project specific. Investors with an interest in a project are willing to invest in data gathering relative to that project, but will be disinclined to gather more wide-ranging information because of the extra cost, so they will invariably favour this type of baseline development.

Even though a project specific baseline should produce the most accurate assessment of the likely environmental additionality of a CDM investment, there still may be considerable uncertainties due to the counter-factual nature of baselines, especially with relation to future fuel and technology choices [Begg *et al*l, 1999].

Experience to date indicates a clear need for a uniform reporting format for each project type -with a fair trade-off between the desirability for intensive data (to reduce the likelihood of cheating) and the transaction costs imposed by the data gathering process.

MULTI-PROJECT BASELINES

Multi-project baselines would operate at the sub-sectoral or sectoral level, and be focused on average emission rates (for example t CO_2/GWh) rather than specific emission levels. The advantage of this approach is simplicity, relative transparency, and lower cost [Ellis and Bosi, 1999].

Although less suited to accurate prediction of the likely environmental additionality of a specific project, this approach can reduce the likelihood of gaming at the project level.[6]

In the literature, there is some debate about where the baseline level should be set. The level could reflect the country average; the regional average; the country average or regional average for recently installed technology; or the best equivalent already installed in the host country.

HYBRID PROJECT BASELINES

Experience with the AIJ pilot phase has highlighted the possibility of a wide divergence in emissions reductions for similar projects undertaken in different circumstances [Ellis and Bosi. 1999]. To reduce this tendency and lower transaction costs, it has been suggested that standardisation of some of the many project-specific baseline components could be undertaken, resulting in baselines intermediate between the two extremes of project-specific and multi-project.

Such a “hybrid” baseline could be applicable to a small number of projects, with local and regional variability of the different baseline components determining the extent to which standardisation is feasible.

KEY BASELINE ISSUES

Regardless of which type of baseline is favoured, a number of key issues need to be settled before CDM projects can really get off the ground as a viable greenhouse gas mitigation mechanism.

The issues identified in the literature include:

- The static vs dynamic approach
- The emissions timeline
- How baseline data are generated

DYNAMIC VS STATIC BASELINES

If a baseline is fixed at the start of the project and remains constant throughout its lifetime despite what is happening in the real world (static baseline), the number of credits generated by the project is known in advance and makes planning and investment decision-making easier. There is also a lower administrative, monitoring and reporting burden with this approach.

On the other hand, if the baseline is revised at intervals throughout the life of the project to reflect technology, fuel choice and other changes in the real world, the baseline will more accurately reflect the true additionality of the project over its lifetime but lead to increased transaction cost and uncertainty for investors.

EMISSIONS TIMELINE

The total number of emissions credits generated by a project is greatly affected by the length of time over which the credits can be accrued. In the absence of agreed standardisation with respect to project lifetimes, even similar projects may end up with widely differing timelines - depending on the willingness of the investor and host economy to extend the period over which credits will accrue.

It has been suggested that a standard methodology should be developed to calculate emissions timelines to increase transparency and comparability between projects.

DATA SOURCES

The data sources used to develop a baseline could be historical - based on past performance, a snap-shot of current performance, or a simulation of likely future performance. It is considered that the adoption of these different data types will influence the perceived credibility of the baseline, as well as the data, monitoring and reporting requirements, transparency, and the levels of free riders and gaming associated with a particular baseline [Ellis and Bosi, 1999].

CHAPTER 4

CREATING A SOUND CDM INVESTMENT ENVIRONMENT

INTRODUCTION

In theory at least, CDM could be an important vehicle to help carry the Kyoto Protocol into action. APEC economies consisting of both Annex I and Non-Annex I parties are paying growing attention to the possible usefulness of this mechanism as a practical and potentially flexible way in which real GHG emission reductions could be achieved.

As an economic growth powerhouse, the region has a great potential for GHG emission reductions. However high energy supply growth has not been unfettered, there are accompanying problems, such as capital limitations, limited local R&D investment, and a general weakness of institutional frameworks. Although CDM projects will represent new investment by private firms from developed economies, the regional constraints on economic development may limit the ability of the CDM to achieve its true potential. This could be particularly so for electricity sector projects, which are highly dependant on supporting infrastructure. Timely investments may also not be made due to uncertainties related to profitability and risk arising largely from distrust of the stability of regulatory regimes, shifts in energy and environmental policies, and unstable fiscal systems.

New concepts and technologies can take a long time to become accepted and institutionalised. This is a major concern with respect to the CDM, because time is a critical factor in mitigating GHG emissions within deadlines already agreed to in international negotiations. An additional hurdle already alluded to earlier in this report is the seriously dampening effect the CDM rules, as they have been formulated to date, are likely to place on actual implementation of this worthy idea.

One suggestion is that an interim system of rules and practices be encouraged in order to advance the concept in a simpler fashion in its formative stage. The interim system would be an acid test of whether CDM projects could make a significant contribution combating climate change.

UNDERSTANDING THE ECONOMICS OF GHG EMISSION CONTROL

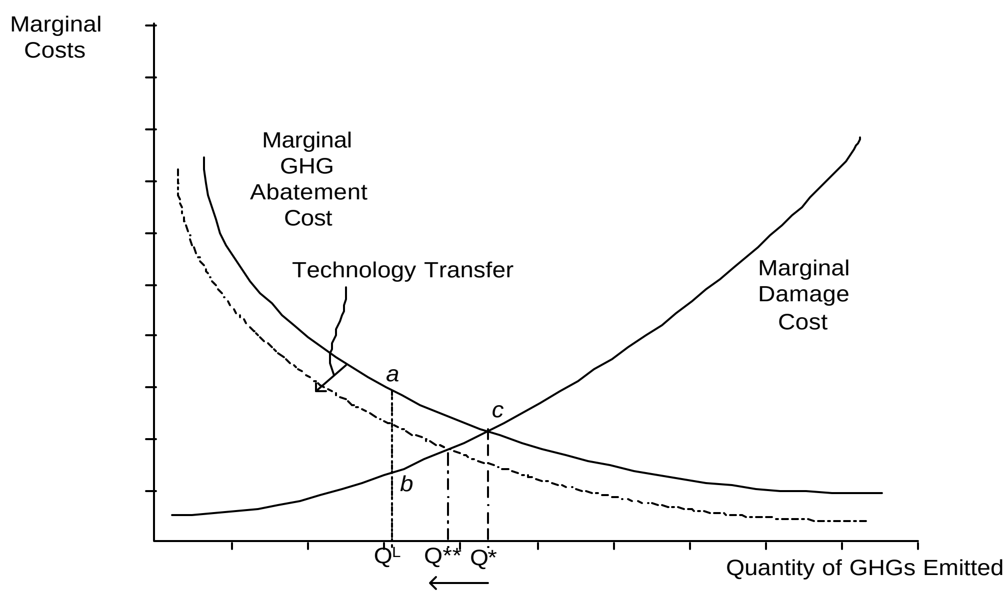
The economics of CDM projects depend on a range of economic, social and political factors. This section will attempt to illustrate how an optimal level of emission reduction might be determined as a basis for the subsequent discussion.

Greenhouse gases are “fund” pollutants that can be absorbed and removed to some extent by the natural environment. For example, carbon sinks such as new forests and oceans can absorb excess carbon dioxide.[7] Carbon dioxide can also be removed from the atmosphere (or removed from processes that lead to atmospheric emissions) with a sufficient level of investment. From an economics perspective, the benefits of the investment are weighed against the costs to determine whether the investment should be made.

A major problem with respect to this type of analysis is the lack of consensus on estimates of damage from GHG emissions. While the potentially harmful consequences of global warming can be theoretically modelled, these are only approximations of the real economic and environmental effects of substantially higher atmospheric concentrations of carbon dioxide and other greenhouse gases.[8] The inability to model accurately the complete global climate system and to estimate associated socio-economic GHG impacts confines us to a conceptual level of operating.

What is the economically efficient allocation of greenhouse gases? To answer this question, we could consider the marginal abatement cost of greenhouse gases. In general the level and slope of the marginal abatement cost curve are difficult to estimate, but the curve is believed to be downward sloping, as seen in Figure 2. The downward sloping marginal abatement cost curve shows that the cost of reducing a given amount of emissions (cost per million tonnes of carbon dioxide, for example) increases as the amount of avoided emissions increases, assuming that the cheapest abatement options are used first. This explanation corresponds to movement from right to left along the marginal abatement cost curve in Figure 2.

Figure 2 Efficient allocation of GHG gases



The marginal cost of damage increases with the amount emitted, hence is upward sloping in the diagram. The rationale behind the positive slope is that relatively small amounts of anthropogenic greenhouse gases are not seriously harmful, being below the radiative forcing threshold [IPCC, 1994]. As feedback mechanisms in the environment offset small additions of greenhouse gases, damage from low emissions levels can be considered minimal. However very large amounts of additional greenhouse gases (as we now see being emitted worldwide), could lead to irreversible damage to the environment, hence leading to very large cost effects.

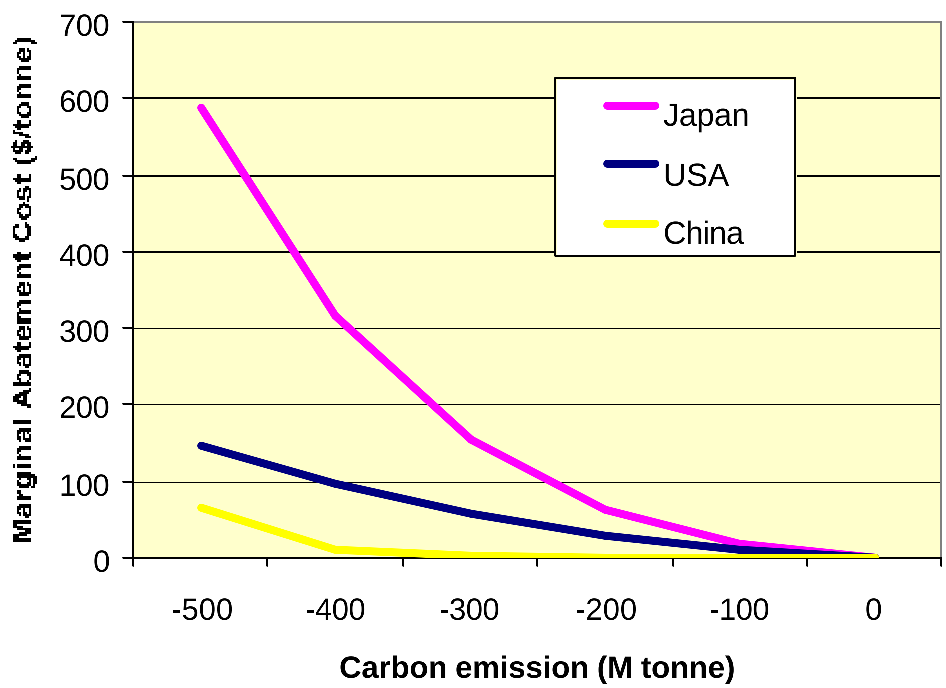
In theory, the economically optimal level of emissions occurs where the marginal abatement cost equals the marginal cost of damage. The efficient allocation of GHG emissions takes place at Q*, where the (perceived) marginal cost of damage matches the marginal abatement cost. Keeping in mind that the areas under the curves represent total damage cost and total abatement cost respectively, if the level of control is on the left of Q*, say QL, the total cost would rise by the area enclosed by points *a*, *b*, and *c*. And the same holds true for the cases where allocation of GHG emissions occurs on the right hand side of Q*. Thus GHG emissions will converge to Q*.

The marginal GHG abatement cost is influenced by:

- The level of GHG emission reduction technology development;
- Factor input costs for GHG abatement projects such as labour and capital costs;
- Economic structure - the contribution of commercial, household, industrial and transportation sectors to GHG emissions;
- Institutional factors such as laws and regulations, and policy orientation toward environment protection;
- Financial factors including taxes, tariffs and subsidies; and
- Size of available GHG sinks.

There have been numerous attempts to estimate marginal abatement costs, mostly based on costs of emissions reductions, or so-called CERI curves. Ellerman and Decaux (1998) estimated marginal abatement costs in a number of economies including China, the United States and Japan. As shown in Figure 3, Japan exhibits the highest marginal abatement costs in 2010 of the three economies shown, which point to the relatively high energy efficiency levels (leaving little room for domestic abatement options) in Japan.

Figure 3 Marginal abatement curves for 2010 for selected APEC economies



Source: Reconstructed from Ellerman and Decaux (1998)

The factors determining the marginal cost of damage include:[9]

- The degree of vulnerability to GHG related natural disasters such as sea-level rise and desertification;
- The level of economic development (as a proxy for economic loss);

- Per capita income;
- The perceived value of the environment; and
- Population density (reflecting the health risk).

In reality, these factors are closely interrelated and the marginal curves may not be independent. For example, an economy with high per capita income will tend to have steep marginal cost of abatement and marginal cost of damage curves, reflecting relatively high technology standards and willingness to pay a premium for environmental quality.

As CDM is a mechanism to transfer technology from Annex-I Parties to non-Annex I Parties, the transfer will tend to shift the marginal abatement cost curve downwards, lowering the optimal level of GHG emissions from Q* to Q** as shown in Figure 2.

It is not difficult to see that the reduction of GHG emissions depends not only on abatement cost factors, such as technology choices, but also on the slope of the marginal cost of damage curve. This implies that technology plays a less important role in economies with steep damage cost curves (primarily Annex I economies, which have already tapped the cheapest opportunities). As a result, developed economies incur higher marginal abatement costs than developing economies.

SOME MACRO-ECONOMIC ISSUES REGARDING CDM

SUSTAINABILITY AND SHIFTS IN POLICY ORIENTATION

Economic growth is a primary policy focus in developing economies, and investment capital is often either insufficient or unsuitably allocated to allow for much environmental conservation or to allow environmental policies to keep pace with economic growth. As a consequence, environmental degradation has become severe in some economies, and associated health costs have risen substantially. Increasing environmental degradation and pollution loadings have led some policymakers in the region to rethink the value of the environment, and to consider the long-term sustainability of current practices.

Growing numbers of people in the world's largest cities, particularly in developing economies, are under severe health risk. According to the latest World Energy Assessment household solid fuel use alone causes around 2 million deaths a year in women and children worldwide. At the community level, urban air pollution caused largely by fuel combustion is a leading cause of pre-mature deaths. [UNDP, UNDESA, WEC, 2001]. According to a press release by the World Resources Institute [WRI, 2000b] more than 80 percent of all deaths in developing economies were attributable to air pollution-induced lung infections, and were children under 5 years of age. Given that air pollution from the combustion of fossil fuels accounts for most of this atmospheric pollution, any mechanism (such as CDM) that reduces air pollutants (even as a side benefit) will have a large impact on health care costs. An increase in health care costs will shift the marginal damage cost curve upwards.

Another aspect of sustainability is the efficient use of depletable resources. For finite resources the marginal user cost rises over time, assuming the marginal cost of extraction is constant.[10] The increasing scarcity rent on fossil fuels is of serious concern to developing economies undertaking the long journey of economic development. The early importation of new technologies under favourable terms and conditions (such as envisaged through CDM projects) would assist these economies in making more efficient use of scarce resources in the future.

Climate Change is a global issue, and understandably at a local level, support is limited in developing

BEIJING'S CLEAN AIR PROGRAMMES

Beijing municipality has been looking for measures to solve the city's air pollution problem for some time. In 1996, the municipality government established the "Beijing Implementation Programme on Total Pollutants Emission Control in the Ninth Five-Year Plan." In accordance with the programme, leaded-gasoline was banned in the city and natural gas consumption was promoted after the construction of a pipeline from the Shanganning field in late 1997. With these efforts, air quality has improved. But in the process one important barrier was identified: the relatively high initiation charge for end-users of natural gas.

Late 1998, after receiving approval from the State Council of the Central Government, the Beijing municipal government issued an "Announcement of Emergency Measures to Control Air Pollution in Beijing" which is now called, "18 Measures" in short. Among the 18, the first measure was tight monitoring of the quality of coal used in Beijing and imposition of strict penalties on coal users who use low quality coal. Then followed three measures to help shift from coal to clean fuel such as natural gas. They include not only a ban on the construction of new coal firing facilities within the vicinity of the city, but also an order to convert current coal fired facilities to natural gas. There are other measures targeting auto-vehicles for emissions mitigation.

Air quality has improved as a result of the implementation of the "18 Measures." In an attempt to advance the programme, the Beijing Government issued yet another programme in early 1999 entitled "Announcement of Second Phased Measures to Control Air Pollution in Beijing." It is often called "28 Measures." The target is to increase natural gas consumption in Beijing to 0.7 billion cubic metres (BCM)/year by the end of 1999 to fully utilise gas from the Shanganning gas fields. It requires 40 Non-Coal Zones in Beijing by the end of 1999.

After authorization by SDPC's pricing department, the Beijing municipality is able to increase the SO2 emission fee by 2.5 to 6 times from September 1999. This is also part of efforts to promote fuel switching from coal to natural gas in the city.

On March 11, 2000, the Beijing government issued its "Announcement of Fourth Phase Measures to Control Air Pollution in Beijing," which mandate the municipal planning commission to establish a new medium and long term plan for energy mix adjustment and to undertake a feasibility study on the use of 1.8 BCM per year of natural gas, and a pre-feasibility study on the use of an additional 4-5 BCM. The target amount of natural gas consumption in 2000 has been set at 1 BCM in total.

economies. In contrast, local air pollution is now having a significant bearing on the formation of energy and environmental policies in many economies in the APEC region. Notably, Northeast Asian economies have begun to pay more attention to improvements in environmental quality in cities and townships. As a result governments in the region are reinforcing environment standards and encouraging a change in the energy mix toward more environmentally friendly resources. CDM projects can potentially assist in this process.

PROJECT LEVEL ISSUES

INVESTMENT UNDER UNCERTAINTY

The proposed CDM project framework is not much different from that for commercial projects, and investors must allow for a number of barriers to successful investment. The main factors constituting a favourable CDM framework include:

- A transparent legal and regulatory regime;
- Stable economic, financial and fiscal systems, including a stable tax policy;
- Market driven pricing mechanisms;
- Guarantees of repatriation of profits;
- Appropriate environmental standards;
- Efficient and cooperative governments at local and national levels.

In developing economies, these factors may be absent or operative ineffectively, thus adding to the investment risks of technology transfer projects.

Considering the high up-front capital costs and long life spans of many environmental or energy projects, investments are not easily reversed once committed. Kolstad (1996), in describing the concept of irreversibility, argues that once investment is made in pollution control capital, and it later turns out that actual damage is low, the abatement capital stock cannot immediately be withdrawn.

The irreversibility effect can delay investment decisions, favouring (irreversible) investments being made later rather than sooner. Irreversibility differs from risk aversion in that it is related to the temporal aspect of decision-making, apart from the risk itself. Carruth, Dickerson, and Henly (1998) further argued that the investment irreversibility effect could offset any positive anticipated returns on investment made under uncertainty, which are normally correlated with higher marginal profitability of capital. Profitability may not adequately compensate for uncertainty in decision making for long-term environment projects.

How would irreversibility affect participation of developing economies in CDM projects? In general, CDM projects will use up GHG mitigation options leaving not only more expensive, but also less options for the future, because investment capital stocks and potential areas of GHG emission abatement are limited in developing economies. In this regard, the participation of host economies in CDM projects could be adversely influenced by the uncertainties about their status under the UNFCCC and returns from CDM projects to them.

RATE OF RETURN ON CDM PROJECTS

SUBSIDIES

Policy makers utilise price signals as one important means of achieving policy objectives. Energy prices (transport fuels and electricity tariffs being notable examples) are often subsidised by governments to achieve social goals, such as rural electrification, maintaining international price competitiveness, protection of domestic industry, and so on. Whilst subsidies may underpin noble policy goals, they tend to discourage both domestic and foreign investors because they distort the operations of the market.

An IEA report [IEA, 1995] indicates that average levels of power price subsidies are 10.89 percent in China, 32.52 percent in Russia and 27.51 percent in Indonesia - in comparison to a reference price. To illustrate, in Indonesia, the government has been providing substantial direct subsidies to the state electricity company PLN. The electricity tariff after the 1997 financial crisis has fallen to around US 3¢/kWh, which is far below the actual supply cost of about US 6-7 ¢/kWh [Hoetomo, 2001]. Under these circumstances it is not impossible to recover investment costs, let alone maintain a reasonable rate of return from building a power plant unless the same levels of subsidisation are extended to private investors

Despite the negative impacts of subsidies on foreign capital investment, subsidy removal is likely to face strong public resistance, making such a policy shift difficult. The recent surge in oil prices in 2000, in particular gasoline prices in the mid western states of the US, illustrates the difficulty of changing the tax structure of energy commodities to more closely reflect true costs. Especially in developing economies, social policy changes of this nature can lead to social unrest, which then works to undermine economic stability and social cohesion at a broader level.

DISCOUNT RATE

As a result of the latest Asian financial crisis, a painful lesson has been learned by economies in the region, including Korea and Thailand - that over-reliance on short-term bank financing to fund longer-term projects can lead to a financial disaster because of mismatches in loan maturity [Lee, 2000]. Extensive short-term borrowing from banks was not necessarily the preference in these economies, but was imposed by the lack of bond markets.

CDM projects will tend to involve large capital investments, due partly to the technology requirement imposed by the baseline in Article 12 of the Kyoto Protocol.

As shown in Table 1, discount rates are still prohibitively high in some developing APEC member economies although they have exhibited declining trends in recent years in most APEC economies.[11] High discount rates reflect the scarcity of domestic capital, signifying the importance and role of foreign capital. From the perspective of foreign investors however, discount rates reflect investment risks. It's not unusual for foreign investors to demand relatively high rates of return, reflecting the risk premium.

An additional dimension of high discount rates is the issue of public acceptance of long-term environmental projects. As Panayotou (1998) pointed out, the combination of capital scarcity and high discount rates influences the selection of projects. Governments as well as the general public will be more reluctant - the higher the discount rate - to agree to projects requiring high initial capital costs, but yielding dividends over a long period of time. Today is more important than tomorrow with rising discount rates. Under these circumstances, CDM projects could be of little interest to policy makers. Moreover since private discount rates are even higher than official rates, one can easily see public resistance to these types of projects.

EXCHANGE RATE RISK

If capital expenditure, operating and maintenance expenses, revenues and debt service payments are all in the same local currency, there is no exchange risk. In some cases, however, revenues are generated in the local currency while other payments are made in a foreign currency, usually US dollars.

Most APEC economies (except for Malaysia) do not have exchange controls, even after the financial crisis of 1997. Volatile exchange rates, in particular, rapid depreciation of local currencies, can easily make projects unexpectedly insolvent. For energy and environment projects with long construction lead times and life expectancy, exchange rate volatility is of critical concern to investors. In some cases, lenders can hedge this risk using instruments such as currency futures or long-term forward foreign

Table 1 Central bank discount rates in selected APEC member economies

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
					Asia					
Brunei	-	-	-	-	-	-	-	-	-	-
China	7.92	7.2	7.2	10.08	10.08	10.44	9	8.55	4.59	3.24
HK, China	-	-	4	4	5.75	6.25	6	7	6.25	7
Indonesia	18.83	18.47	13.5	8.82	12.44	13.99	12.8	20	38.44	12.51
Japan	6	4.5	3.25	1.75	1.75	0.5	0.5	0.5	0.5	0.5
Korea	7	7	7	5	5	5	5	5	3	3
Malaysia	7.23	7.7	7.1	5.24	4.51	6.47	7.28	-	-	-
Philippines	14	14	14.3	9.4	8.3	10.83	11.7	14.64	12.4	7.89
Russia	-	-	-	-		160	48	28	60	55
Chinese Taipei	7.75	6.25	5.63	5.5	5.5	5.5	5	5.25	4.75	4.5
Thailand	12	11	11	9	9.5	10.5	10.5	12.5	12.5	4
Viet Nam	-	-	-	-	-	-	-	-	-	-
					North America					
Canada	11.78	7.67	7.36	4.11	7.43	5.79	3.25	4.5	5.25	5
U.S.A.	6.5	3.5	3	3	4.75	5.25	5	5	4.5	5
South America										
Peru	289.6	67.65	48.5	28.63	16.08	18.44	18.16	15.94	18.72	17.8
					Oceania					
Australia	15.24	10.99	6.96	5.83	5.75	5.75	-	-	-	-
New Zealand	13.25	8.3	9.15	5.7	9.75	9.8	8.8	9.7	5.6	5
P.N.G*.	9.3	9.3	7.12	6.39	-	-	-	-	-	-

Source: IMF (2000). "International Financial Statistics". and The Central Bank of China (2000). "Financial Statistics"
Unit: percent per annum, end of period

exchange rate contracts. For CDM projects in developing economies, currency futures are not applicable as these contracts are traded only with respect to the currencies of a small number of developed economies - for example, the Japanese Yen and US dollar.

Foreign exchange risk hedging instruments add to the cost of financing, which will in turn lower the net benefit of projects. Hence economies facing volatile exchange rates are seemingly unattractive target for investment.

REGULATORY REFORM AND CDM

As noted in the APERC report on electricity deregulation [APERC, 2000], most APEC economies are either contemplating or implementing energy sector reforms, particularly in the electricity sector. Regulatory reform is intended to introduce competition to the sector to improve efficiency. In deregulated markets, high cost technologies requiring substantial capital investment tend to be avoided, as competition puts pressure on costs.

Stakeholders in deregulated, competitive markets tend to be short-term oriented, because long-term benefits are less easy to sell to shareholders and Boards of Directors.

One effect of electricity sector reform has been substantially increased utilisation rates for baseload coal-fired power plants in some APEC economies. High capacity factor utilisation has been encouraged by the very competitive price of steam coal and the competitiveness of mine-mouth power stations burning lignite. A good case in point is Victoria, Australia, where increased use of existing power stations burning highly polluting brown coal has led to substantial increases in CO_2 emissions.

As shown in Figure 4 and Figure 5, coal consumption for power generation in the US and Australia has increased significantly relative to other fuels over the last two decades. Electricity sector reform could potentially exacerbate this situation.

Hansen (1998) argued that, faced with the uncertainties created by deregulation - such as loss of protected service areas and/or long-term contracts - electricity generation investment is likely to face higher financing costs. Such an effect would discourage investment in power plants with high capital costs and long-term payback periods. There may be some truth in this assertion, although the indications are that this is not a serious concern. In fact, this could prove to be a very positive benefit of electricity sector reform.

With the recent emergence of the combined cycle gas turbine - with its high efficiency, lower capital costs, shorter construction lead times, rapid start-up cycle, and reduced environmental impacts - the encouragement of this and other smaller-scale power generation technologies (many exploiting renewable resources), may prove very beneficial to the industry.

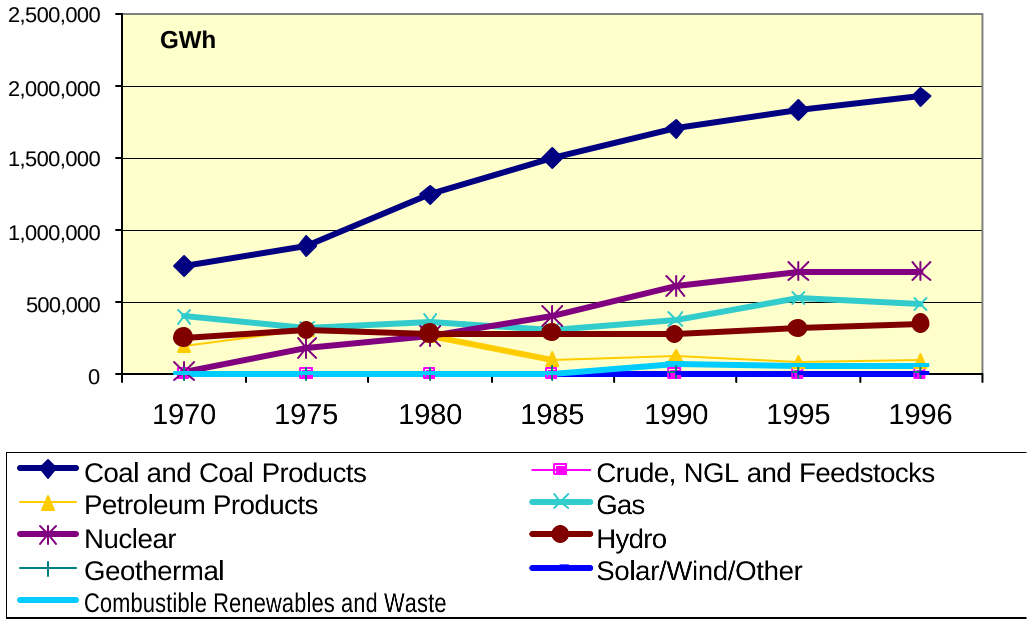
How would these developments impact on the Clean Development Mechanism, in particular on power generation projects in developing economies? In a highly competitive electricity wholesale market, generators will seek to minimise costs, and this will tend to favour old, inefficient coal-fired power stations with no emission controls. At least this will be so in the absence of air quality standards and/or emission control policy measures.

On the other hand, where natural gas is available, the attractiveness of a CCGT plant to an IPP is clearly evidenced by the considerable amount of investment already going in this direction. This becomes an issue with respect to the design of additionality rules, an issue discussed elsewhere in this report.

Nogee (2000) proposed nationwide legislation in the United States (or an amendment to the current legislation) requiring all power plants to meet the same emission standards in an effort to retire old and inefficient coal fired power plants. The Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992 actually did help increase natural gas consumption in the electricity sector. He further suggested the creation of a Public Benefits Fund aimed at “maintaining a prior level of spending on energy efficiency, renewable energy, research and development, and sometimes on low-income services,” as well as the establishment of the Renewable Energy Portfolio Standard ensuring the long-term market for new and renewable technologies.

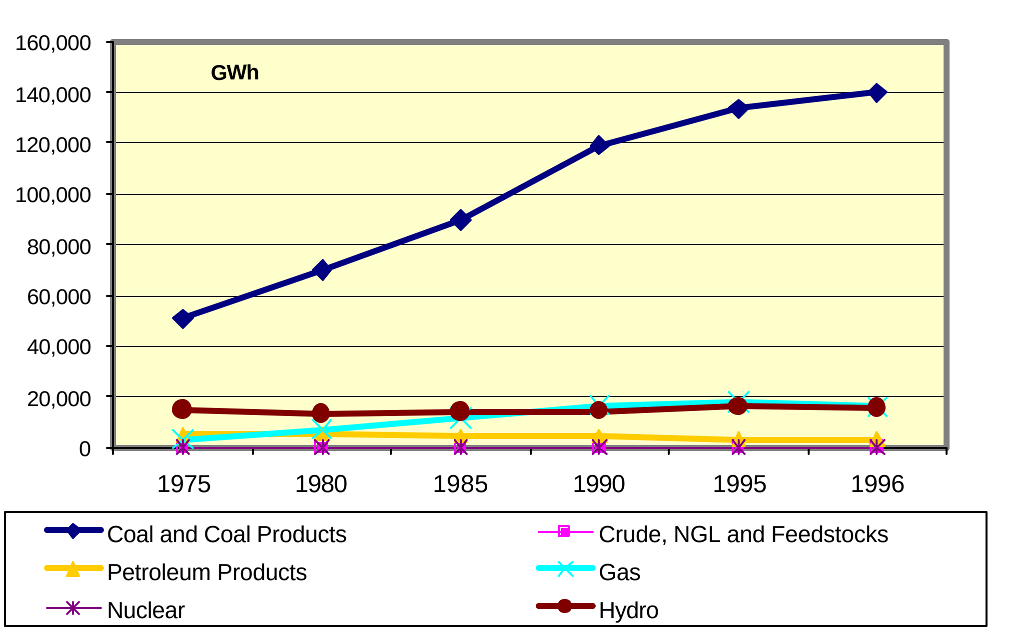
CDM projects, particularly, those involving emerging technologies (for example, new and renewable projects) in deregulated markets will face an uphill battle unless adequately supported by public policy initiatives. The question boils down to whether there exist incentives and the means for governments and consumers in developing economies to provide such support to CDM projects.

Figure 4 Power generation fuel mix trends in the US



Source: IEA (1998b)

Figure 5 Power generation fuel mix trends in Australia



Source: IEA (1998b)

LOW HANGING FRUIT

Some Non-Annex I economies face an additional hurdle in hosting CDM projects. It is not inconceivable that early participation in CDM projects can conflict with the national interest in the long run. Newly industrialised APEC economies such as Korea and Mexico have been the targets of failed attempts by some Annex-I parties to place them within the Annex-I commitment regime - under labels such as “Evolution,” and “Voluntary Participation.” In essence, some Annex I parties want at least some Non-Annex I parties to make binding GHG reductions commitments.

Some developing economies fear that CDM participation might be viewed as an indication of a willingness to accept emissions targets at a later stage, or at least will weaken their negotiation position. In addition, there is concern that CDM benefits may not be large enough to justify hosting projects. This is particularly so for economies such as Korea, with power plants that are already amongst the world's most efficient. If foreign investors claim the easy credits (the low hanging fruit), this will leave only the high cost options if target commitments are made at a later stage (although the price of CERs will rise to compensate for this).

To date, there is no clear indication on how this issue is to be resolved through the UNFCCC negotiation process. One plausible solution is to include a buyback option in the CDM package that host economies could reclaim, at the least, a portion of the CERs at a mutually agreed price. This will provide them with incentives to participate in CDM projects even in the early stage.

One remaining issue is how to set the price at the right level. Klaas (2000) proposed that “the exercise price of the buyback option should equal the estimated cost of generating the credits had the projects been undertaken at the time of the buyback.” This proposal sounds rational, perhaps, to host economies, but not to the investors since it forces them to take risks favouring only the host economies without proper compensation to the investors. To those investors who intend to sell carbon offsets at the market price, the cost-plus carbon offset price will not be acceptable.

CDM AND FDI

The CDM is similar to Foreign Direct Investment (FDI) in that both involve international private sector investment. The difference is that CDM projects are targeted specifically at developing economies and at GHG emissions reduction. Understanding the factors that affect foreign investment decision-making provides a useful framework for understanding CDM investment decision-making. Therefore, firstly a definition of FDI is provided. Secondly a theoretical framework for determining FDI factors is demonstrated, and thirdly, an FDI case in China is explained on the basis of the theoretical arguments.

DEFINITION OF FDI

According to the OECD, Foreign Direct Investment (FDI) is defined as international investment, which is made in order to obtain a lasting interest by a resident entity in one economy (“direct investor”) in an entity resident in an economy other than that of the investor (“direct investment enterprise”) [OECD, 1999; IMF, 1993]. The lasting interest means there will be a long-term relationship between the investor and the enterprise of the host parties. Also a significant influence on management would be envisaged, and the foreign investor will probably hold more than 10 percent of the shares.

The ownership of 10 percent of shares or voting stock is a criterion whether an investment is categorised as direct investment or not. FDI is affected by the ability to earn profits on activities in a foreign economy. On this account, there is a significant difference between FDI and Foreign Portfolio Investment (FPI). FPI refers to holdings of securities and other financial assets such as investment on derivatives. FPI does not imply active involvement in management.

FDI can take various forms as follows:

- The purchase of existing assets in a foreign economy;
- New investment in property, plant & equipment in a foreign economy;
- Participate in a joint venture with a local partner in a foreign economy and
- Cross Border M&A.[12]

UNDERSTANDING FDI

Various economic theories have provided an analytical framework for FDI. Hymer first provided explanations of FDI by clarifying the difference between portfolio investment and direct investment. His theory explains that the foreign direct investor is motivated to locate their business abroad in an expectation of earning economic rent through transferring resources (not only capital but also technology, management skills and entrepreneurship).

Venron developed a product cycle hypothesis. This theory relates FDI to the product development cycle. Firstly, corporations tend to locate their research base in developed economies, such as the USA, where they can employ educated human capital. Then, at the commercialisation stage, they locate their mass production base in rapidly industrialising economies (Japan in the 1960s and Korea and Chinese Taipei in 1980s), where production processes can utilise relatively cheap, but well-educated human capital. The investment made to these economies takes the form of FDI to export products back to the developed economies.

The most recent theory, provided by Dunning, is best characterised as an "OLI" framework. This theory identifies three advantages in doing business abroad: Ownership advantages, Location advantages, and Internalisation advantages.

Ownership advantage:[13] Doing business abroad results in additional costs because of cultural and language differences, or lack of knowledge of the local market. However, a foreign direct investor has certain advantages with respect to their own production process or their own unique product. Also firm specific know-how, information and brand names owned by foreign direct investor can give good reasons for doing business abroad. These advantages offset the disadvantages by generating higher revenues or lowering costs when investors utilise relatively lower factor input costs such as cheap labour and capital investment.

Location advantage: Location advantages can be factors such as the resource endowment, level of economic development, social structure and political stability of the host economy. Also foreign direct investors take into account these location advantages, including the market size and potential future market development in the host economy when making investment decisions.

Basically there are two types of foreign direct investment that utilize location advantage: local market-oriented FDI and export-oriented FDI. For the first, the level of economic development, market size, and future prospects for economic development are important determining factors for foreign investment. Export-oriented investors set up enterprises in particular places to utilise resources endowment and labour at lower costs and expect to be very competitive in export.

Internalisation advantage: Internalisation provides the advantage of reducing supply costs with respect to import licensing and tariff barriers.

These three OLI factors can be further classified into supply-side and demand-side factors. The ownership and internalisation advantages are supply-side factors. The location advantage is a demand-side factor.

Dunning's OLI framework covers various essential elements underlining FDI. It is useful for analysing recent decision-making FDI patterns. Below is an FDI case in Guandong Province in China explained on the basis of the OLI framework. Also, it explains the role of FDI in the economic development to hosting parties.

CHINA-GUANDONG CASE

China is one of the largest FDI recipients in the world. For instance, in 1998 FDI inflows accounted for 25.9 percent of total inflow to the developing economies. Since the first foreign investments 1979, FDI has grown annually by 26.4 percent to 1998. As Table 2 shows, FDI made contributions to investment and industrial output.

Table 2 Role of foreign direct investment in China: 1991-1996

	1991	1992	1993	1994	1995	1996
FDI/Gross Domestic Investment	3.3%	6.40%	10.70%	17.50%	13.50%	12.20%
FDI exports/total exports	17.00%	20.40%	27.50%	28.70%	31.30%	40.70%
FDI imports/total imports	n.a.	32.70%	40.20%	45.80%	47.70%	54.50%
FDI industrial output/total industrial output	5.00%	6.00%	9.00%	11.00%	13.00%	14.50%

Source: EIU, China Market Atlas, 1997

Guandong province plays a leading role with respect to FDI. In 1997, for instance, FDI inflows reached US$ 11.7 million, 25.9 percent of total FDI inflows to China. And in 1998, FDI inflows to Guandong reached US$ 12.0 million, which is 26.4 percent of the total. Guandong has successfully achieved economic development with effective use of FDI. The province's real GDP growth from 1979 to 1995 was 14.2 percent, while the FDI growth rate was 34 percent during the same period.

The pattern of FDI inflow to Guandong is influenced by the relatively well developed markets and infrastructure, and the strong ties with Hong Kong. Compared with the other provinces, Guandong is more developed and successful economic development supported by FDI has greatly assisted in providing physical infrastructure, such as highways, ports, and air cargo transportation.

Hong Kong, China (HKC) is the largest investor in Guandong, with 2,300 HKC enterprises and 80,000 factories producing export goods for Hong Kong. Investment from HKC, accounted for approximately 78.1 percent of total FDI in 1995 [Statistical Yearbooks of Guangdong]. The Pearl River Delta, where these factories are mainly located, has become the site for re-export to HKC. To utilise relatively cheap labour, enterprises locate their production sites and produce labour-intensive and relatively easy-processing products for export for HKC.

These location-specific advantages have provided enterprises from HKC good reasons for doing business in Guangdong, where well developed market conditions and relatively lower factor input costs are available. The relative short distance to the export market in HKC has contributed to the inflow of

FDI also. On top of these location factors, preferential treatment such as tax breaks facilitated the investment from abroad.

IMPLICATIONS FOR CDM INVESTMENT DECISION-MAKING

Because CDM projects are designed to contribute to GHG emissions reduction (as set out in Article 12 of the Kyoto Protocol), there are additional costs. These will be compensated for through revenue from carbon credits. For instance, costs incurred from project monitoring, verification and certification are supposed to be supported from carbon credit revenue.

Presumably, CDM investments will be concentrated in areas where location advantages are offered, offsetting the uncertainties or costs relating to ratification of the Kyoto Protocol. The following factors are likely to affect CDM decision-making:

- Reasonable local market size or prospects of promising market development in the future;
- Physical infrastructure that facilitates business operations; and
- Access to transparent legal system or political stability.

CDM host economies could reap the benefits of lower emissions of sulphur and nitrogen oxides, and there are a growing number of economies providing economic incentives for investments resulting in reductions of emissions of these gases. In this regard, CDM projects could ask for more favourable investment-related terms and conditions from host governments as long as they are shown to be consistent with existing government policy goals and objectives.

THE COGEN MODEL

The CDM project case studies in this report were modelled with COGEN,[14] an energy project assessment model developed by the Lawrence Berkley National Laboratory.

COGEN allows consideration of two aspects of a project - environmental assessment and financial assessment. Originally it was designed to assess the feasibility of renewable energy or energy efficiency improvements against conventional technologies. For the purposes of our research, the COGEN model was modified and somewhat simplified to allow project assessment of the following three cases compared against conventional coal fired power generation:

- A coal fired power generation unit displacement project.
- A combined cycle gas turbine generation unit displacement project.
- A wind power generation unit displacement project.

The structure of the modified COGEN model is illustrated in Figure 6. Basically there are two flows of information. One is physical data, with assumptions about installed capacity, capacity factor, and thermal efficiency of the technology. Fuel inputs required to meet the generation output are estimated based on the efficiency level of generating units. The fuel requirement is then transformed into estimated carbon emissions. For the carbon intensity of various fossil fuels, IPCC data is used. The carbon emissions from displacing generation units are compared against generalised benchmark baseline emissions.

The model also requires financial information, comprising cost and revenue data. Revenue comes from electricity and carbon credit sales. The electricity sales price per kWh is assumed on the basis of assumptions used by the Samsung Environment Research Centre. The carbon price is based on three scenarios: high, middle and low price cases. Costs include capital investment, operation and maintenance costs, and fuel costs. The data for these costs are based on NEA and IEA information. Finance is divided into equity and debt to simplify matters.

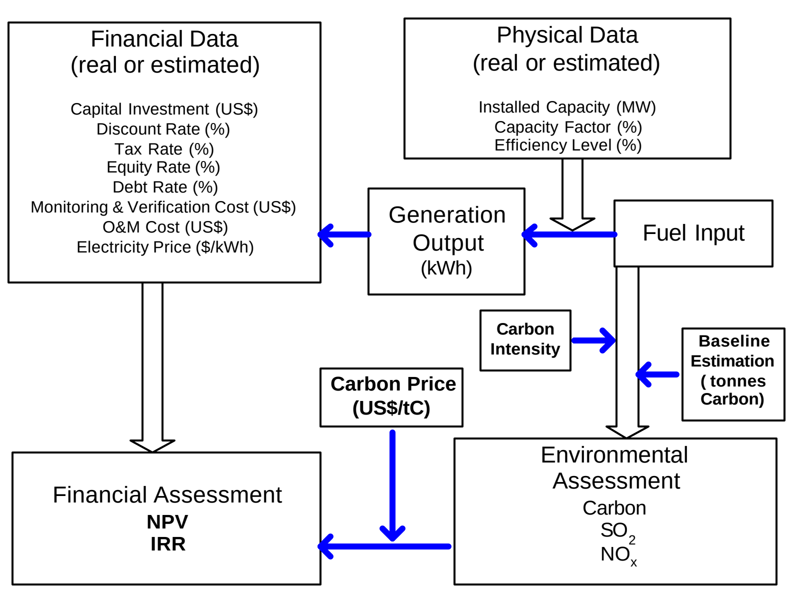
The financial assessment calculates Net Present Value (NPV) and Internal Rate of Return (IRR).

NPV is the difference between the present value of total revenue earned over the lifetime of the project and the present value of the total lifetime cost. NPV methodology suggests that investment should be made when the present value of total revenue exceeds the total costs. In other words, only when NPV is positive.

$$\text{Net Present Value} = \sum_{i=1}^{n} \frac{(revenue - \cos t)}{(1 + rate)\wedge n}$$

IRR is the discount rate that makes NPV zero. In other words, IRR represents the discount rate that equalises the present value of revenue and the present value of the total costs. If IRR is estimated at 8 percent, when the (real) discount rate is 3 percent, this project is evaluated as financially feasible, since NPV is positive.

Figure 6 Structure of the COGEN model



PROJECT ASSESSMENT

The three projects modelled below represent displacement of a Chinese coal-fired power generation unit with: (1) a higher efficiency coal-fired generation unit; (2) a CCGT generation unit; (3) a wind-power generation unit.

COAL FIRED GENERATION UNIT DISPLACEMENT PROJECT

The thermal efficiency of the unit to be replaced is assumed to be either 25 percent or 35 percent, the basic assumptions being shown below in Table 3.

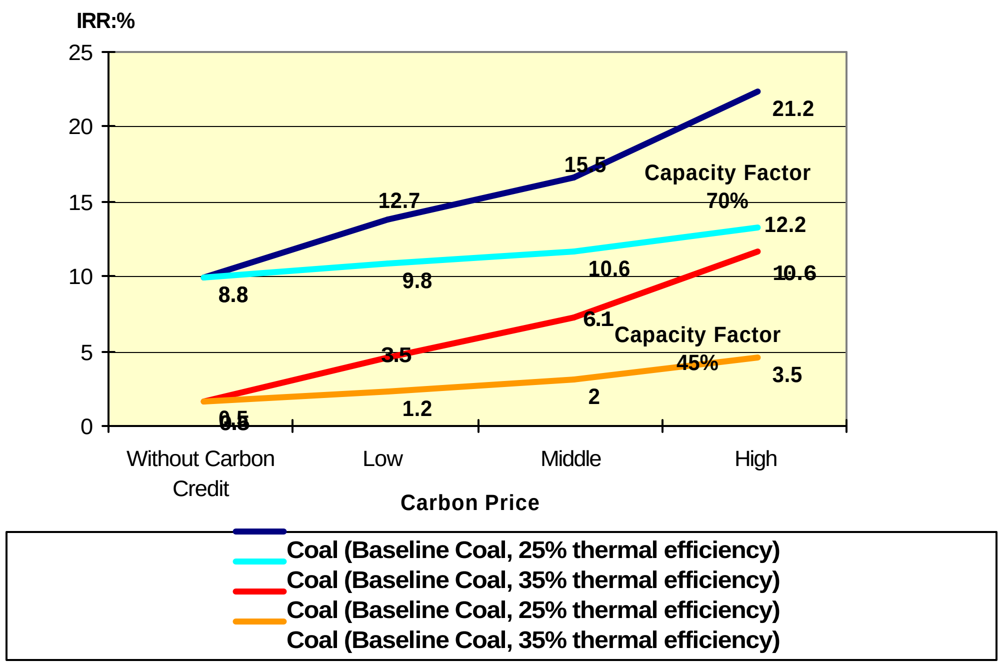
Figure 7 shows the modelling results. Except for the case of the coal-fired replacement unit with 45 percent capacity factor compared against 35 percent thermal efficiency coal generation unit, other cases show favourable results. Three key factors contribute to the difference in IRR - revenue from electrici-

Table 3 Basic assumptions for coal-fired power unit replacement scenario

Installed Capacity	15,000*2(kW)	Fuel Price	1.7$/GJ	Electricity Price	0.046$/kWh
Capacity Factor	45% or 70%	Fuel Price Escalation	0.80%	Monitoring cost/year	30,000$
Plant Efficiency	40%	Capital Investment	1,000$/kW	O&M Cost	0.016$/kWh

Note: Cost assumptions are taken from NEA/IEA. Electricity Price assumption is based upon the estimate done by Samsung Global Environment Research Centre. Monitoring cost is estimated by APERC.

Figure 7 IRR for coal-fired generation unit displacement project



ty sales, carbon revenue and capacity factor.

Since most of the total revenue comes from electricity sales, the capacity factor has a major influence on revenue. Differences in carbon revenue change the level of IRR. Depending on the level of baseline GHG emissions and carbon price, the share of carbon revenue changes significantly, ranging from 1 percent at the lowest to 19 percent at the highest.

COMBINED CYCLE GAS TURBINE DISPLACEMENT PROJECT

The assumptions used for the CCGT displacement project are shown in Table 4. This project is compared against a coal-fired generation unit with thermal efficiency of 25 percent or 35 percent. The capacity factor is set at 45 percent, assuming that the gas unit will be used for mid-load power. The fuel price is set at US$ 3/GJ for a low price scenario and US$ 4/GJ for a high price scenario. This reflects the uncertainty regarding possible natural gas utilisation rates and market price of gas in China.

Table 4 Basic assumptions for CCGT replacement scenario

Installed Capacity	150,000*2(kW)	Fuel Price	3$/GJ or 4$/GJ	Electricity Price	0.057$/kWh
Capacity Factor	45%	Fuel Price Escalation	1.50%	Monitoring cost	30,000$/year
Plant Efficiency	45%	Capital Investment	700$/kW	O&M Cost	0.018$/kWh

Note: Cost assumptions are taken from NEA/IEA. Electricity price assumption is based upon an estimate by the Samsung Global Environment Research Centre. Monitoring cost is estimated by APERC.

Figure 8 IRR for CCGT generation unit displacement project

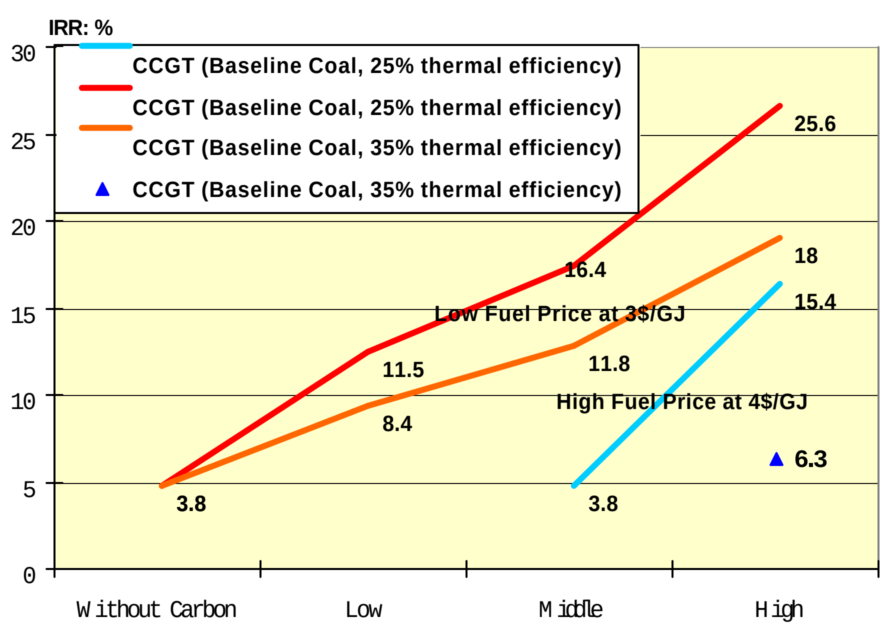


Figure 8 shows the result of the model run. The result indicates the significance of fuel price and carbon price on project performance.[15,16]

The two low fuel price cases demonstrate favourable project performance with a minimum of 11 percent IRR. The high fuel price case becomes financially feasible with the additional carbon revenue of mid-price and high-price carbon credit scenarios. The results highlight the importance of carbon price level with respect to project financial feasibility.

WIND GENERATION DISPLACEMENT PROJECT

The assumptions for a wind generating displacement unit are shown in Table 5. The wind project is compared against a coal-fired generation unit with 25 percent or 35 percent efficiency.

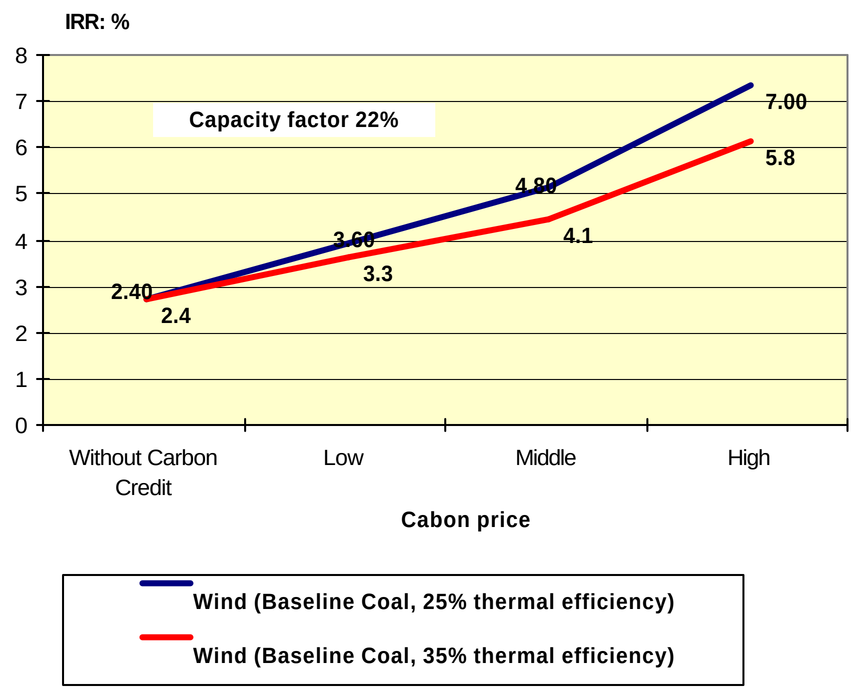
Figure 9 shows the modelling results. Taking into account of the Chinese discount rate at 3.24 percent [The Central Bank of China, 2000] in 1999, the result demonstrates that carbon credit revenue assist in making project financially feasible.

EFFECT OF CARBON CREDITS ON ELECTRICITY PRICE

The effect of carbon credit price on the price of electricity can be modelled. The IRR is set at 10 percent, and the price of electricity is then calculated, based on a number of carbon credit price scenarios, as used for the above case studies. The results are shown in Figure 10. The electricity supply costs are averages over a 20 year project period.

Although there are differences in the degree of impact, carbon revenue lowers supply cost. The CCGT case demonstrates a significant lowering of price from US$ 0.049/kWh (without carbon revenue)

Figure 9 IRR for wind generation unit displacement project



Notes: The red line is the 25 percent baseline, and the orange line the 35 percent efficiency coal baseline

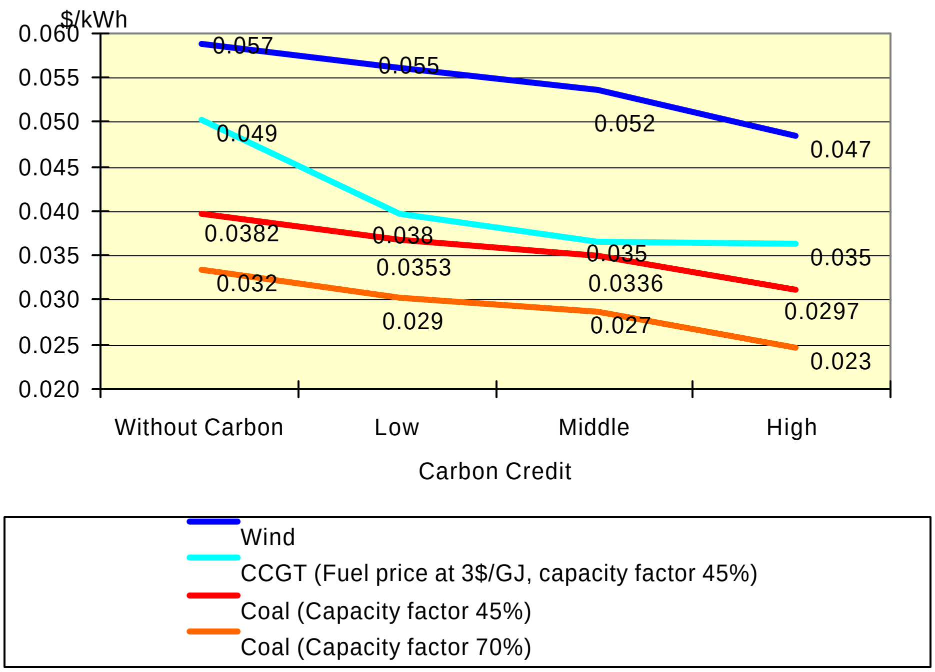
Table 5 Basic assumptions for wind generation replacement unit scenario

Installed Capacity	10,000(kW)	Electricity Price	US$ 0.057/kWh
Capacity Factor	22%	Monitoring cost/year	US$ 30,000
Capital Investment	US$ 1,000/kW	O&M Cost	US$ 0.01/kWh

Note: Cost assumptions are taken from NEA/IEA. Electricity price assumptions are based on estimates by Samsung Global Environment Research Centre. Monitoring cost is estimated by APERC.

to US$ 0.035/kWh (with carbon revenue at high carbon price). In the wind case, sales price is lowered from US$ 0.057/kWh (without carbon revenue) to US$ 0.047/kWh (with carbon revenue at high carbon price).

Figure 10 Effect of carbon credits on electricity price



Notes: IRR = 10 percent. Baseline coal thermal efficiency = 25 percent

EFFECT OF TAX ON IRR

Figure 11 shows the results from the wind generation unit displacement project case. The light blue line shows the IRR before tax, and the green line shows the IRR after 20 percent income tax is imposed. The results clearly show that tax breaks can contribute to improvement of financial viability.

Figure 11 Impact of Tax on IRR

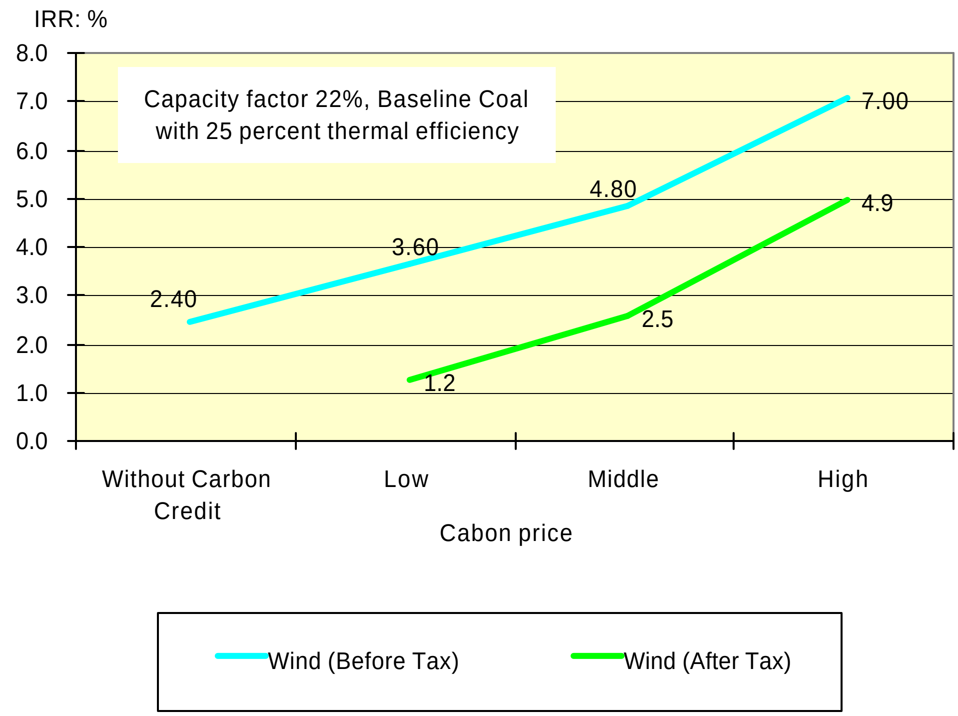


Table 6 Generation cost comparisons

		Nuclear	Coal	CCGT	Wind	Solar	Fuel Cell
Generation Cost	$/kWh	0.027	0.03	0.041	0.069	0.654	0.199
Supply Cost	$/kWh	0.043	0.046	0.056	0.069	0.654	0.199

Source: Samsung Global Environment Research Centre. Green Samsung Autumn 2000.

CONCLUSIONS

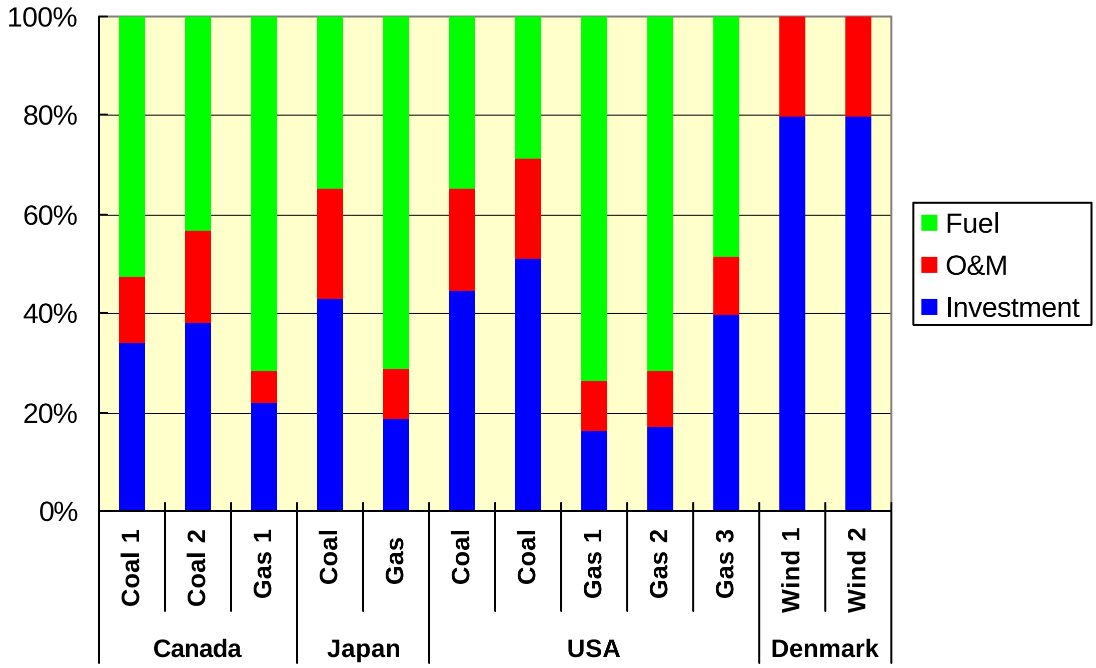
With the same CDM projects, benefits as well as cost will differ from economy to economy. The levels and shapes of marginal GHG abatement cost and marginal damage cost curves will determine the cost and benefits from CDM projects.

Except for the additional revenue from the sales of carbon offsets, the determinants of CDM investment flow will be overlapping for the most part with those affecting FDI.

At a macro level, policy orientation and changes in regulatory frameworks in host governments will be important while at a project level rate of return on investments, stability of exchange rates and discount rates play crucial roles in attracting CDM investment.

We undertook some simulation exercises based on the COGEN model to identify and better understand key economic factors determining the viability of the CDM projects. This model has limitations

Figure 12 Breakdown of generation costs for various power generation technologies



Source: NEA and IEA, 1998.

with respect to country risks such as tax risks and exchange rate risks mentioned earlier in this section of the report. Also, transaction costs required for verification and certification are left out due to uncertainties with respect to their likely impact on project costs.

Despite these limitations, the results suggest important implications generally applicable to these types of projects. Even though the majority of revenue comes from electricity sales, the contribution of carbon credit sales to project performance can be important. For example, a CCGT displacement project in a situation where natural gas price can become financially viable if extra revenue can be earned from carbon credits (if the carbon credit price is reasonable high). Also, carbon revenues could greatly assist renewable projects.

CHAPTER 5

ELECTRICITY SUPPLY - A PRIME CDM TARGET

INTRODUCTION

The Clean Development Mechanism, like the other Kyoto flexibility mechanisms, is meant to be voluntary and market based. Beside the need to certify emission reductions, the mechanism relies on investors taking advantage of market opportunities, with a GHG mitigation incentive built in - an ability to lower the overall costs of compliance with the Kyoto Protocol.

As shown by recent demonstrations across Europe and in other places, attempts by governments to use regulation as a tool, in this case to increase fuel taxes as a means of limiting demand and internalising environmental costs may have already reached a political limit. As noted in a recent media brief by the Cambridge Energy Research Associates (CERA): "If economies begin to falter under continued high energy prices, then governments may find that they must choose between environmental regulations that push up the energy prices - untenable in the current political environment - or lower energy prices that are more politically palatable. They may also turn, reluctantly, toward broader use of greenhouse gas emissions trading. Depending on which choice is made, the result could well be to shift the balance in sustainable development policy in favour of market-driven approaches" [CERA, 2000].

The above quote refers to emissions trading, but the term "market based instruments" could equally apply. From a climate change policy perspective, the transportation sector will be one of the most difficult to deal with because fuel combustion by individual consumers is widely dispersed and transport fuels tend to have low price elasticity.

By contrast the generation of electricity, as one of the other major contributors to localised and regional pollution, and to growth in GHG emissions, tends to be more amenable to emission control than the transportation and other sectors because of the limited number of localised point sources, the availability of modern technologies to improve plant efficiency and hence emissions, and the availability of economical alternative low carbon (or even zero-carbon) fuels. [17]

According to a recent IEA World Energy Outlook, world CO_2 emissions from the electricity sector represent over one third of world annual energy-related CO_2 emissions and are projected to increase at an annual rate of 2.7 percent between 1995 and 2020 [IEA, 1998].

According to the World Resources Institute: "increasing the efficiencies of boilers and power plants is a target for multilateral financial assistance (through the World Bank and Global Environment Facility) and a potential target for the Kyoto Protocol's Clean Development Mechanism, designed to promote the transfer of cutting-edge technologies that lower greenhouse gas emissions to developing economies" [WRI, 2000a].

As China is by far the largest consumer of coal in the Asia Pacific region for power generation (outside the US), it is worth focussing on the potential to improve thermal combustion in this economy. The average boiler efficiency in China is only 55-65 percent, compared with 80-85 percent for systems using more current technologies according to the WRI. Thermal efficiencies of Chinese coal-fired power plants are also relatively low, at 29-32 percent, compared to current technologies that deliver 40 percent (for coal) to over 50 percent (for natural gas combined cycle) efficiencies." This is probably true for other developing economies in the region burning coal in conventional thermal power stations.

Despite dramatic improvements in energy efficiency, China remains one of the most carbon- and energy-intensive economies in the world, relying on coal (the most carbon-intensive fossil fuel) for 75 percent of its commercial energy consumption. China's own studies indicate a potential to further reduce industrial energy use by 40-50 percent. Switching from coal to natural gas would also dramatically lower carbon dioxide emissions and improve air quality [WRI, 2000a].

Outside of China, and aside from the possibility of improving coal boiler fuel efficiency, there are other excellent carbon emission mitigation opportunities in Non-Annex I economies in the Asia Pacific Region. The carbon intensity of the electricity sector in individual regional economies, and potential CDM opportunities, are dealt with in more detail in Chapter 8.

FUELS FOR POWER GENERATION

COAL'S GLOBAL ROLE

One hundred years ago much of the industrial world was almost entirely dependent on coal. Since then coal's share of primary energy supply has declined substantially. Oil became more widely available in the mid 20th Century, and rapidly became the fuel of choice for most forms of transportation, a sector that expanded greatly after the Second World War. Natural gas, nuclear and large-scale hydro were also developed for power generation, and competed with coal for this purpose. As industrialised economies expanded and became more technologically sophisticated, electrification became widespread, and the energy consumed by each individual increased greatly.

While the market share of coal has fallen, global demand has increased greatly due to its use in electricity generation, and cement and steel production. Today, coal contributes about 27 percent of global primary energy demand, second only to oil. Coal is used to produce 37 percent of the world's electricity, and approximately 16 percent of global hard coal production is used to produce 70 percent of total global steel production [Cain, 2000].

China is the largest consumer and producer of coal in the APEC region and is expected to contribute 52 percent to coal demand growth from 1995 to 2010 [APERC, 1998]. Southeast Asia is expected to show the most rapid growth, rising 3.4-fold (8.6 percent pa) over the forecast period. Coal is used predominately for power generation in the APEC region and power generation's share is projected to rise from 58 percent in 1995 to 66 percent in 2010.

Coal production is projected to increase 39 percent (2.2 percent pa) from 1385 Mtoe in 1995 to 1921 Mtoe in 2010. China is expected to contribute 57 percent of the 1995-2010 increase. APEC is a small net exporter of coal although the level declines slightly in the APERC baseline scenario.

THE GROWING IMPORTANCE OF NATURAL GAS

Gas consumption in APEC is projected to increase 63 percent (3.3 percent pa) from 770 Mtoe in 1995 to 1253 Mtoe in 2010, more than twice the rise from 1980 to1995 [APERC, 1998]. China is expected to show a 3.7-fold (9.1 percent pa) increase over the forecast period, the largest increase among the APEC economies. The United States remains by far the largest consumer and producer of gas. Gas consumption for power generation in the APEC region is projected to more than double from 1995 to 2010, contributing 48 percent of the increase in gas demand.

Gas production rises more rapidly in the forecast period (44 percent, 2.5 percent pa) than in the historical period (26 percent, 1.5 percent pa). China is expected to show the largest percentage increase, rising 3-fold (7.6 percent pa) over the forecast period, while the United States has the largest absolute increase.

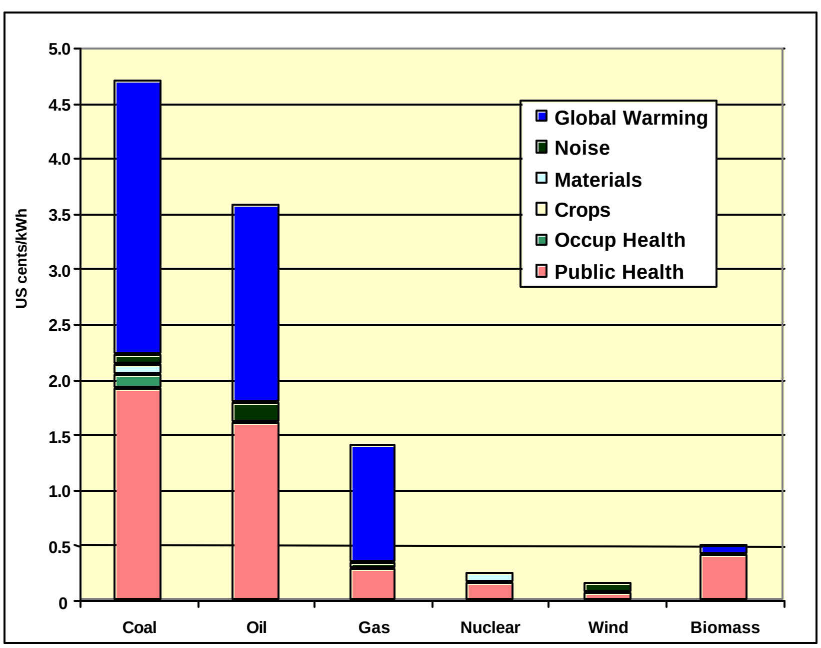
Net imports from outside the region in the baseline scenario are projected to increase 13-fold (18.4 percent pa) by 2010. Net imports comprised less than 2 percent of supply in 1995 but are projected to make up nearly 13 percent in 2010. Northeast Asia will show the largest increase in net imports (70 Mtoe). Southeast Asia and Oceania will increase net exports by a total of 28 Mtoe.

The capital costs of gas-fired combined cycle power plants are substantially lower than for other options, and this provides an important competitive edge in privatised and deregulated energy markets.

There are also other advanced technologies that might provide even more efficient natural gas conversion and end use in the future. Fuel cells, mini and micro turbines, conversion of gas to liquids and production of hydrogen with carbon removal and storage are all options likely to diffuse into the marketplace in the near to mid-term future.

Natural gas is important from another perspective, it has lower environmental impacts than other fossil fuels. In a British study (part of the wider European ExternE Project) that analysed the full fuel cycle from 'cradle to grave' for the main fuels used in the power sector, it was concluded that comparison with the results for the other fossil fuel cycles shows the impacts from the gas fuel cycle are considerably smaller due to the lower atmospheric emissions and higher efficiency of the modern gas powered station (see Figure 13). It was also stated that detailed assessment of GHG emissions from upstream activities undertaken as part of the study did not support claims in the literature that upstream methane losses may give rise to higher global warming impacts than for the coal fuel cycle. [AEAT, 2000].

Figure 13 Impacts of various electricity generation fuel options



Source: AEA Technology, 2000

SUNSET FOR LARGE-SCALE HYDRO AND NUCLEAR?

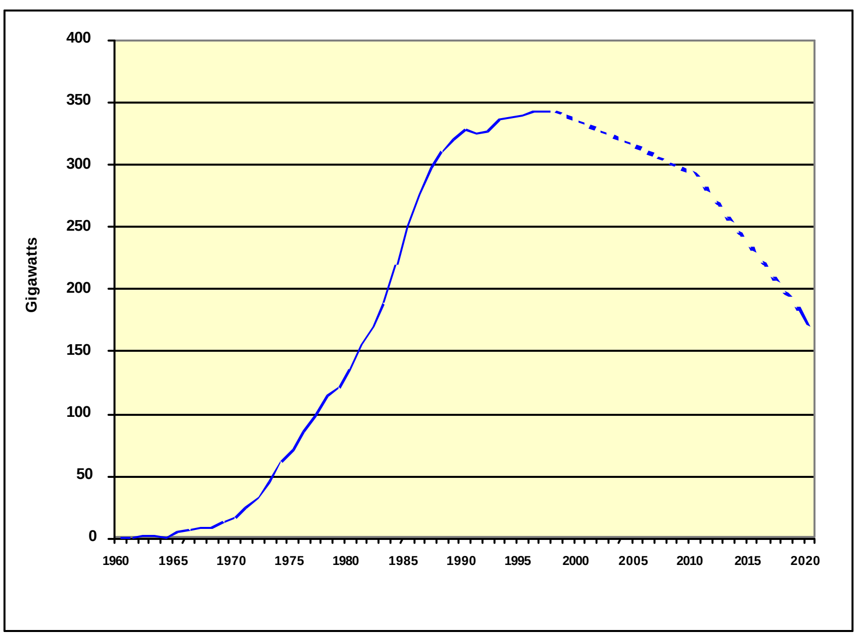
Two power generation fuels that might have been expected to contribute, in an important way globally, to the mitigation of greenhouse gas emissions from energy consumption are large-scale hydro and nuclear. It now appears that these technologies are unlikely to make the desired contributions to this cause, and for a number of important reasons.

With respect to large-scale hydro, many of the easily accessible large-scale resources have already been tapped, even in developing economies. This is because energy-related foreign aid and investment funding have traditionally targeted large-scale hydropower. Secondly, many large-scale projects in developing economies have been dogged by controversy - often because of the displacement and dislocation of whole communities, poorly demonstrated economic and social benefits, and serious impacts on local and regional environments.

Finally, there is growing evidence that large reservoirs are emitters of substantial quantities of greenhouse gases. Recent research [Pearce, 1996] in both Brazil and Canada demonstrate that, regardless of climate, hydropower lakes can emit large quantities of CO_2 and CH_4. In the worst case studied, it is estimated that to date the Balbina reservoir on the River Uatumoã, a tributary of the Amazon, has had about 16 times as potent a greenhouse impact as an equivalent fossil-fuelled power station.

Even in less extreme situations (where the average depth of the reservoir is much greater, the area inundated correspondingly less, and large areas of vegetation are not inundated), greenhouse emissions can still be significant. For example, in Canada it has been found that the two main habitats flooded are sites of intense microbial decomposition and greenhouse gas production when they become inundated. Although opinions differ regarding emission levels from an average reservoir, and the calculation used to

Figure 14 Global growth in net power generation by nuclear



Source: WWI, 1999 and EIA, 2000.

determine greenhouse impact, there is general agreement amongst experts that hydro reservoirs could prove to be a significant part of many nations' outputs of greenhouse gases.

The world's nuclear power generation capacity, after growing more than 700 percent in the 1970s, and 140 percent in the 1980s, has almost stagnated. Nuclear power has gone from being the world's fastest growing energy source to its slowest; according to the Worldwatch Institute and projections made by the US Department of Energy's Energy Information Administration (EIA) under a 'low economic growth case', net generation could fall by half over the next two decades, as shown in Figure 14. [EIA, 2000].

Nuclear power's problems relate to public perceptions and economics. In deregulated power markets, nuclear power is uncompetitive against other power generation technologies (except where capital costs are greatly depreciated), decommissioning and spent fuel storage costs create liabilities few new investors are willing to consider. In terms of health and environmental effects, the possibility of a catastrophic accident, no matter how low the theoretical probability, is a risk the public in many economies are unwilling to take.

NEW RENEWABLES

The role that new renewable energy resources may play in future energy systems has been hotly debated over recent years, along with the growing consensus that global warming is a real issue that must be dealt with.

Standard projections indicate that renewable energy consumption will increase quite modestly in APEC economies over the next decade or two. The 1998 APERC Demand and Supply forecast predicts a rise of 35 percent (2.0 percent pa) in renewables as a component of primary energy supply - from 142 Mtoe in 1995 to 193 Mtoe in 2010. Southeast Asia is projected to have the highest growth rate - 115 percent (5.2 percent pa). Power generation by renewable energy is projected to increase by 46 percent (2.6 percent pa), from 72 Mtoe in 1995 to 105 Mtoe in 2010.

Such modest increases in investment in new renewable energy resources would make virtually no significant contribution to greenhouse emission reduction. Only a large-scale shift in policy thinking and investment patterns could achieve what some commentators consider possible.

For example, Lester Brown, the Chairman of Worldwatch Institute believes “we have more than enough wind, solar, and geothermal energy that can be economically harnessed to power the world economy.” He points to the 39 percent expansion in wind generation worldwide during 1999, the fact that wind already supplies 10 percent of Denmark's electricity, and the view that Mongolia has enough wind resource to double China's national electricity generation. Greenpeace has produced a report that provides a practical blueprint to show that: “wind power is capable of supplying 10 percent of the world's electricity within two decades, even if we do double our overall electricity use in that time” [Brown, 2000].

People in environmental circles also have high hopes for solar energy, particularly photovoltaics, and point to acceleration in solar cell manufacturing, up from an average of 16 percent growth per year in 1990 to 30 percent in 1999. Greenpeace Nederland went as far as commissioning a report by KPMG on the subject of the commercial viability of solar energy [KPMG, 2000].

The KPMG study came to conclusion that three factors could influence the price of PV-systems:

- Technology - solar cell technology is still in a relatively immature state of development, and it is unclear when producers will be able to engage in large-scale manufacturing and offer products at commercially competitive prices;

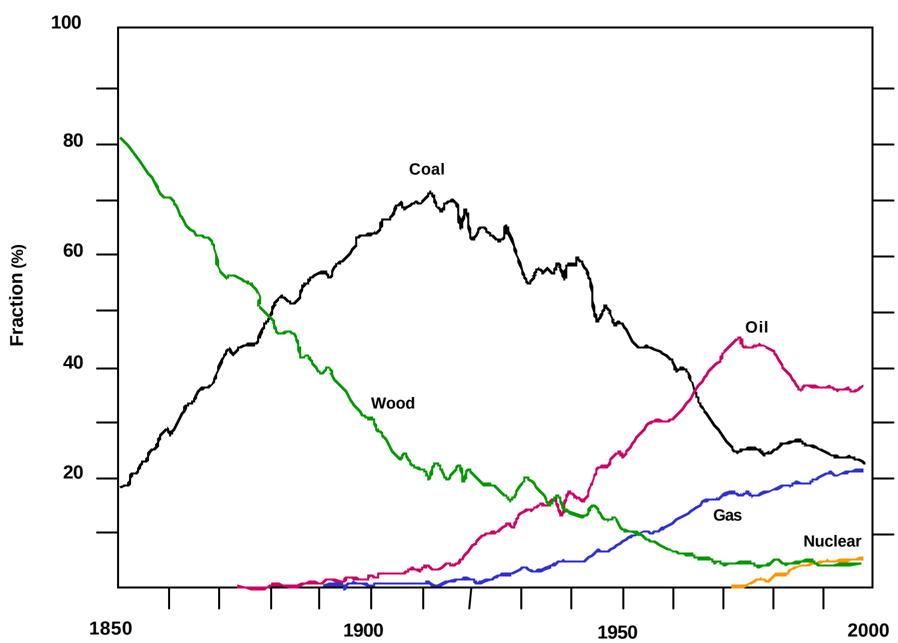
- Subsidy - under current incentives, solar energy's share of total supply cannot be expected to grow rapidly in the foreseeable future; and

- Up-scaling - the large scale production of photovoltaic solar panels is feasible using current technology, and would reduce the price of solar panels by 60-80 percent, making solar a competitive alternative to conventional energy.[18]

For a number of years international oil companies have been investing in technologies that could be commercialised in a future, carbon-constrained world. The world leader, for example in solar PV manufacturing and marketing is BP Solar. BP Solar is a recent amalgam of the former BP Solar with Solarex, and has 20 percent of the world PV market. As noted in the company's promotion material: “major recent projects include multi-million dollar contracts for rural electrification in Indonesia and the Philippines.” Obviously, the majority of sales are in the developed world, and quoted PV electricity rates are usually well above those for electricity generated by other means, but the fact that the technology is being promoted by such an international heavyweight would tend to suggest that technology costs will be driven down over time.

Shell's involvement in renewable energy covers an even broader range: biomass (especially forestry and wood wastes), wind energy, solar energy, and energy conversion systems utilising fuels such as hydrogen. Shell Renewables is in the third year of a $500 million five-year investment plan to make a profitable business from renewable resources. Shell first concentrated on forestry, the use of wood wastes to produce energy, and the manufacturing and marketing of PV panels, before starting to invest in wind energy in 1999.

Figure 15 Historical decarbonisation of primary energy supply



Source: Nakicenovic, 2000

NATURAL GAS AS A BRIDGING FUEL

If one considers the history of energy consumption worldwide, there have been continuously increasing shares of electricity and hydrogen-rich carriers in final energy consumed. It has been argued that the historical replacement of coal by oil, and later by natural gas, at the global level will lead, eventually, to natural gas and later carbon-free energy forms becoming the leading sources of primary energy globally during the 21st century [Ausubel *et al*, 1988].

The potential of natural gas as a relatively clean fossil fuel, and as a bridging fuel to an environmentally sustainable future, appears to be unrecognised by many people, especially some environmental lobby groups. This seems to be because natural gas, like other fossil fuels, is a finite resource, and burning it releases carbon dioxide. This assessment tends to overlook some important considerations however. Firstly, natural gas may be much more abundant than previously thought. According to Nakicenovic in *Global Natural Gas Perspectives* "The perception of natural gas availability has changed dramatically during the last decades. The traditional view is that conventional reserves of natural gas in the world are limited, say to some six decades at current consumption levels. This is strictly speaking still correct. However, this is a static view that is challenged by many recent assessments. It is now quite widely accepted that natural gas resources are quite abundant and more widely distributed than those of oil" [Nakicenovic, 2000].

A second important consideration is that the distribution of hydrogen, or biogases produced from renewable biomass materials, would require similar infrastructure to that used to distribute natural gas. If this infrastructure is developed to deliver natural gas to markets, and a large-scale consumer base is established for natural gas, the same infrastructure could be used to deliver more sustainable gaseous fuel alternatives at some future date.

This is one reason alternative fuels struggle to compete with liquid petroleum products. Their production and distribution is undertaken on a very large scale globally, and hence is very efficient. In the case of petroleum products, this infrastructure was built up over many decades, and was enormously expensive to develop. Moving to other fuels with long-term sustainability characteristics will require a similar scale of infrastructure development.

CHAPTER 6

ENERGY SUPPLY GROWTH & CARBON INTENSITY IN ASIA

INTRODUCTION

Asia is important to the climate change debate for a number of key reasons. Firstly, no other region of the world has demonstrated the same rates of sustained economic growth over the last two decades. From 1966 to 1990, the "Tigers" of East Asia (Singapore, South Korea, Chinese Taipei and Hong Kong, China) showed growth in real income per person of more than 7 percent per year, compared with about 2 percent in the United States [Mankiw, 1997].

Secondly, although this region was relatively poor twenty to thirty years ago, many of the individual economies in the region are now approaching a standard of living long taken for granted in the world's wealthiest nations, and this reality is being reflected in demand for energy. Thirdly, the region is on the whole attractive to investors looking for good returns at reasonably low risk to capital.

High rates of energy and transport sector growth have brought rapid increases in net carbon emissions, and with many Asian economies still undergoing rapid industrialisation, an opportunity exists for developed world political and industry leaders to influence the types of energy sector technologies that are installed over the next one or two decades. Because energy infrastructure is typically long-lived, choices made today have impacts well into the future. Of particular importance are the choice of fuel and associated technologies for power generation, and the infrastructure that must be put in place to support those choices.

Rapid economic expansion in the Asia Pacific region over recent decades has led to a large growth in demand for electricity. In much of the APEC region, demand growth has put a severe strain on the ability of individual economies to expand the electricity infrastructure capacity rapidly enough to meet the surge in demand.

Growth in demand for electricity is outstripping demand for primary energy in the Asia Pacific region, as the region becomes increasingly electrified and per capita consumption rises. This trend is particularly marked in the developing economies. How this rapid growth in electricity demand will be satisfied is possibly one of the most critical issues facing the region over the medium term.

APERC has projected that electricity consumption in Asia Pacific Economic Cooperation (APEC) economies will grow by 65 percent between 1995 and 2010 (an annual growth rate of 3.4 percent) [APERC, 1998]. This compares to a 74 percent (3.8 percent annual) increase for the five-year period 1980 - 1995.

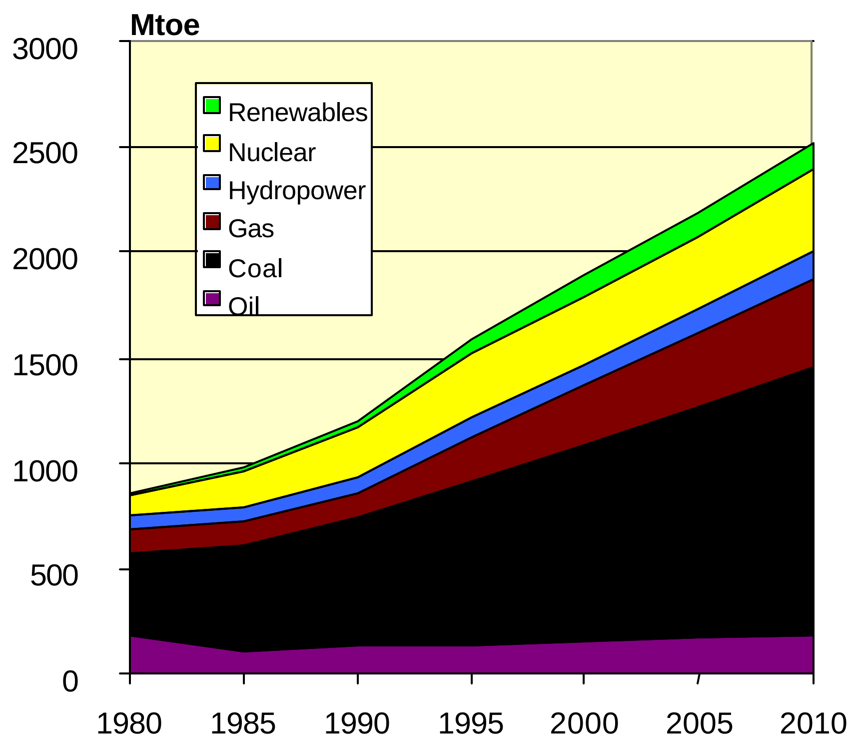
Southeast Asia is expected to have the fastest growth in electricity demand over the forecast period with 7.8 percent per annum, contributing 11 percent of the total APEC increase. East Asia will have the next fastest growth in electricity demand (5.2 percent per annum).

THE ASIA-PACIFIC POWER GENERATION SECTOR

INTRODUCTION

Figure 16 suggests that much of the electricity generation fuel growth over the next decade will be met by coal-fired generation, much of this occurring in China. However, this is a conservative projection (the APERC baseline scenario) based on past trends. This scenario does not take into account radical changes that could occur in fuel markets in the near future.

Figure 16 Projected fuel requirements for electricity generation in the APEC region

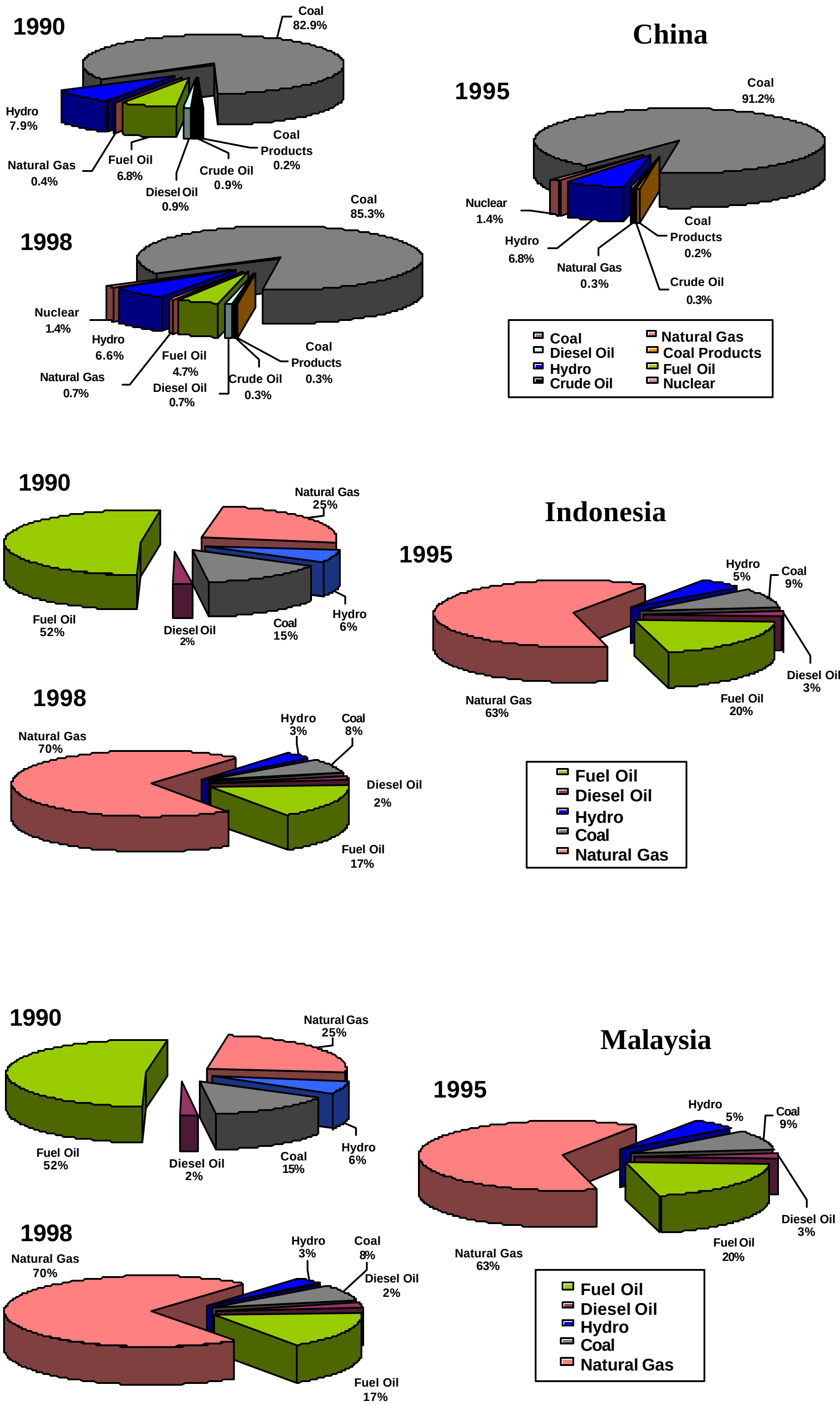


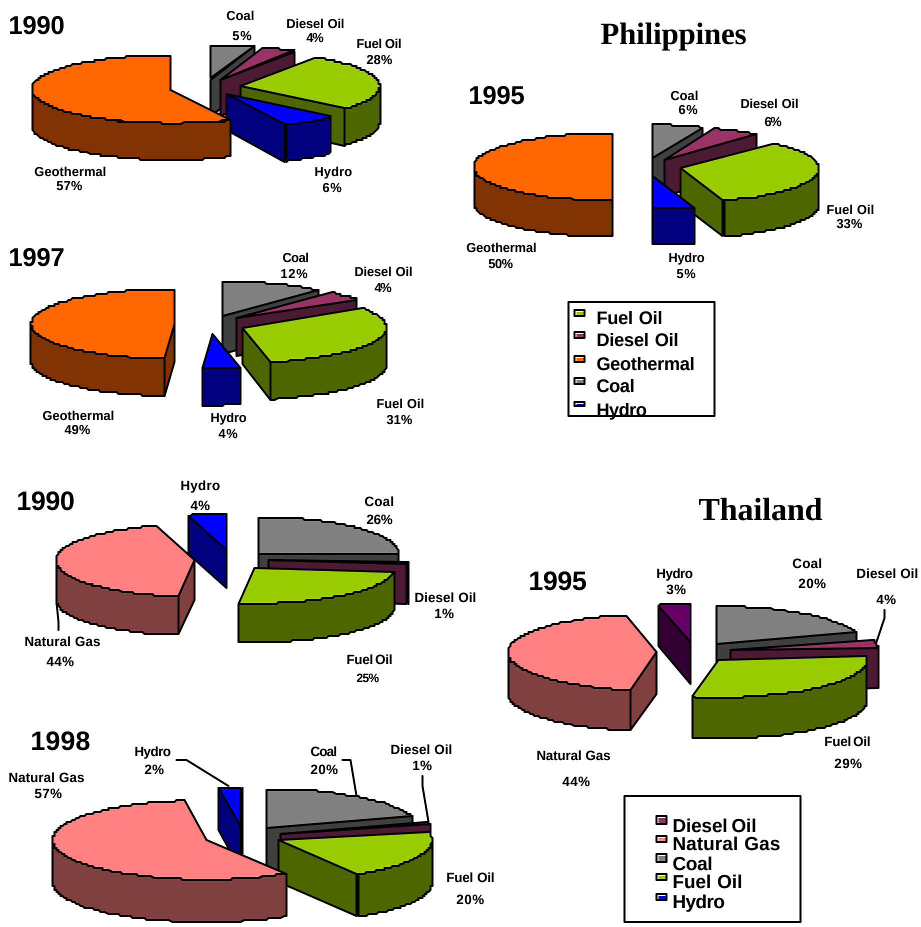
Source: APERC, 1998.

Deregulation of the electricity supply industry has important ramifications for generation fuel markets. This is particularly so for fuels which can compete strongly in a competitive generation market. For example, demand for coal and gas as generation fuels has undergone significant change post-reform in some economies. Coal wins out in economies where it can be mined cheaply and locally - Australia, China and some states in the US. Natural gas is very competitive in economies with abundant local supplies, or where it can be transported by pipeline across borders. It also competes for peak load in situations where it must be imported as LNG (for example in Korea and Japan).

The major factor likely to impinge on the competitiveness of thermal fuels in the mid-term is the environmental externality factor. For example, coal has tended to compete in situations where the environmental impact of emissions of sulphur and nitrogen oxides, carbon dioxide and particulates has not been paid for directly by either producers or users. These costs have tended to be borne by society as a whole, or even by neighbouring economies. However, because consumption of thermal fuels are grow-

Figure 17 Pie charts showing changes in power generation fuel mix with time





Source of data: APEC Energy database. EDMC.

ing exponentially in some rapidly industrialising economies - tracking exponential growth in power supply - and because of increasing public concern about the effects of greenhouse gases and other pollutants on the environment, this issue must be addressed.

The importance of fuel choice, and the dramatic impact this can have in terms of share of net generation in rapidly industrialising economies is demonstrated in Figure 17, which shows the generation fuel mix in selected Asian economies for three dates in the 1990s.

Particularly striking is the very rapid growth in consumption of natural gas for power generation in economies that have abundant indigenous supplies (or ready cross-border access to reserves), and have moved decisively to exploit this resource.

The Philippines has very modest natural gas resources, and is moving to exploit these, but natural gas will be unlikely to play a significant role in power generation in the near future. The Philippines does have large-scale geothermal resources, and has actively exploited these over recent decades. The difficulty of expanding exploitation of the geothermal resource lies more in locality relative to markets than the actual extent of the exploitable resource.

China has large reserves of coal, much of it quite low grade, and potentially huge natural gas resources. The natural gas prospects are largely in the relatively remote western extremes of China, although the Sichuan Basin in the south central region is very large and conveniently located relative to major markets. In China, natural gas has been used mainly in the industry sector, which accounted for 82 percent of total natural gas consumption in 1996, the highest growth among all sectors. The manufacturing sub-sector is the main user. The power generation sector uses a relatively small share of natural gas, partly because cheap coal is readily available. The residential sector also accounts for a small share because of the lack of available supply or transmission and distribution networks.

Below, the electricity sector supply and demand situation for selected Asian economies is presented. The data used to generate the power sector supply growth curves, and that used to generate the electricity sector carbon intensity benchmark baselines shown in this section was taken from the APEC Energy Database maintained by Energy Data and Modelling Center, Institute of Energy Economics, Japan, the database of the International Energy Agency (IEA), and data provided by individual economies.

In the analysis shown below for a number of Asian economies, the construction of benchmark baselines has involved some assumptions. The carbon intensity baseline has peaks that reflect consumption of the major fuel types. Coal is the most carbon intensive fuel, and tends to have a carbon intensity of around 1 kg of CO_2 emitted per kWh of power generated, assuming a conversion efficiency of around

35 percent. Of course, this will vary from plant to plant depending on a number of factors, such as the technology, age and condition of the plant, maintenance practices, and whether the plant runs intermittently or full time. The carbon intensity of gas-fired plants will also vary significantly, as some are single cycle plants (many being retrofitted fuel oil plants), and many of the new ones very efficient combined cycle gas turbine plants. Hydropower and geothermal have for the purposes of this study been classified as non-carbon emitters. This is actually not correct. Geothermal steam typically contains up to 5 percent CO_2, and it is known that hydropower reservoirs emit significant amounts of methane, a much more potent greenhouse gas than CO_2.

CHINA

China is the second largest energy consuming economy in the world, close behind the United States. In 1998, total primary energy consumption reached 1,031 Mtoe (Figure 18), with an average growth rate of 2.9 percent over the period 1980 to 1998.

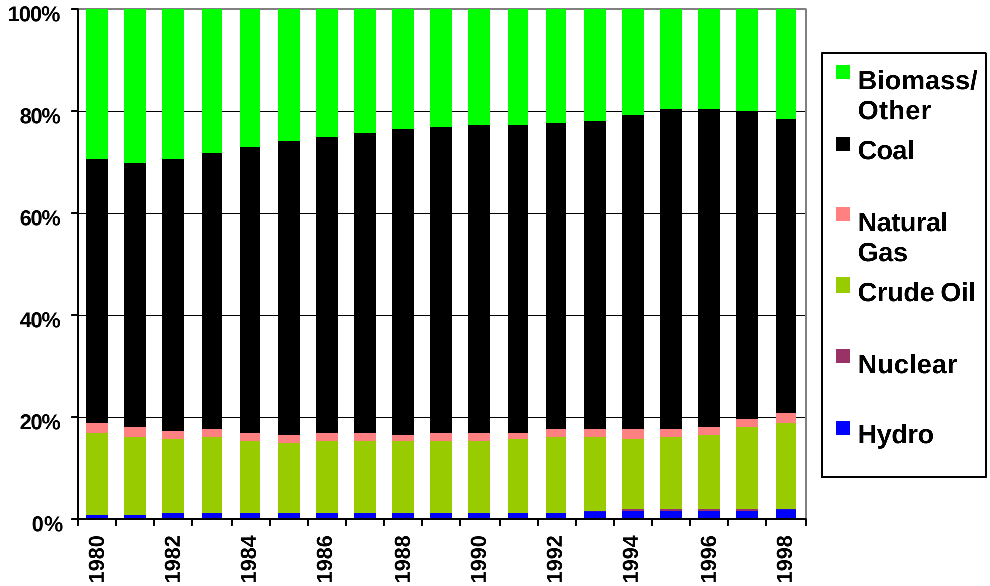
As shown in Figure 19, net power generation growth in China averaged 8.1 percent per year for the period 1980 to 1997. From 1987 to 1997 thermal power plant capacity increased by 8.8 percent, compared to 6.9 percent for hydropower. The first nuclear power station began operation in 1995, and is expected to be followed by other stations. As shown in Table 7, thermal power plants dominate electricity production, accounting for 81.6 percent of total electricity output in 1997.

Figure 18 shows that coal accounted for 57.7 percent of total primary energy consumption, followed by biomass (21.6 percent) and oil (16.8 percent) in 1998. Natural gas and hydropower contributed around 3 percent of supply while nuclear is in the very initial stages of development. Biomass energy is mostly used in the countryside in the residential sector for cooking and heating, although from the 1980s this practice has been in decline, with biomass replaced by coal.

According to forecasts by the China Macro-Economy Research Institution, total primary energy consumption will reach 1854.6 Mtoe in 2020, with coal remaining the dominant fuel with a 51.1 percent share, oil accounting for 18.5 percent, and natural gas growing to 8.75 percent [Fengqi and Dadi, 1999].

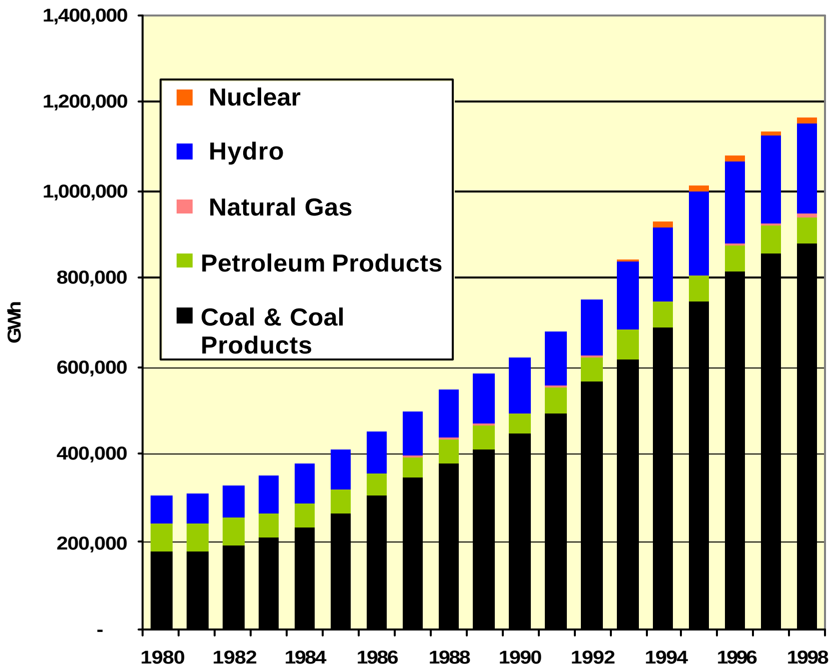
Electricity consumption accounted for 72.5 percent of consumer energy in 1997 in China.

Figure 18 Total primary energy consumption in China (1980 - 1998)



Source: IEA Database

Figure 19 Net power generation by fuel type in China (1980-1998)



Source: EDMC and IEA databases

Table 7 Electricity production in China

	Hydropower (GWh)	Thermal (GWh)	Nuclear (GWh)	Total (GWh)
1987	100,229	397,092		497,321
1989	118,454	466,221		584,675
1991	124,845	552,649		677,494
1993	150,743	685,686		836,429
1995	186,772	807,343	128.33	1,006,948
1997	194,571	925,215	144.18	1,134,204
Average annual growth rate	6.90%	8.80%	6.00%	8.60%

Source: Overseas Electric Power Industry Statistics 1999, Japan

Table 8 Electricity consumption by sector in China

	Industry	Agriculture	Residential	Others
1987	81%	7%	5.50%	6.50%
1989	80.20%	6.90%	6.50%	6.40%
1991	77.80%	6.90%	7.90%	7.40%
1993	76.70%	6.30%	8.90%	8.10%
1995	74.80%	6.20%	10.20%	8.80%
1997	73%	6.20%	11.30%	9.50%

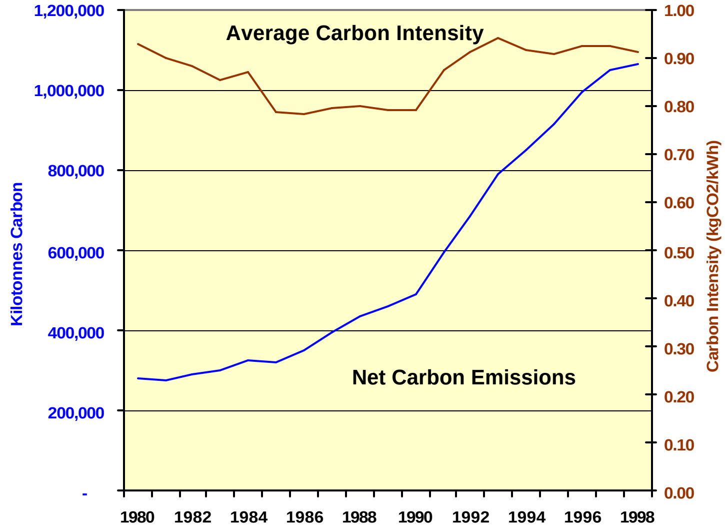
Source: Overseas Electric Power Industry Statistics 1999, Japan

As Table 8 shows, the industrial sector accounted for 73 percent of total electricity consumption in 1997, but the share is declining. Growth is occurring in the residential sector.

Figure 20 shows the growth in net carbon emissions and the general trend in average carbon intensity for the power generation sector in China. As expected from the strong growth in thermal power generation, net carbon emissions have increased markedly over the last decades, and average carbon intensity remains high.

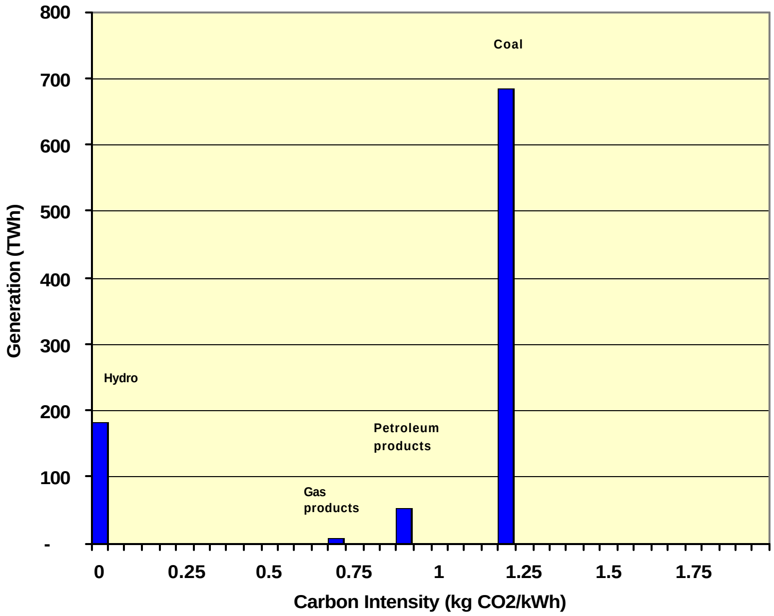
A carbon intensity baseline is shown in Figure 21. As expected, this is dominated by the carbon intensity of coal combustion, mostly in relatively inefficient steam boilers.

Figure 20 China - power sector carbon emissions & carbon intensity (1980-1998)



Source: EDMC and IEA databases

Figure 21 Carbon intensity baseline for the electricity sector in China for 1995



Source: EDMC and IEA databases

INDONESIA

As shown in Figure 22, net power generation in Indonesia grew exponentially between 1980 and 1997, averaging 13.7 percent per year for the period. This rapid growth in supply reflected the government's economic policies targeted at stimulating rapid industrialisation, and the social policy of extending electricity services to as many consumers as possible, and hence promote the overall well-being of Indonesia's population.

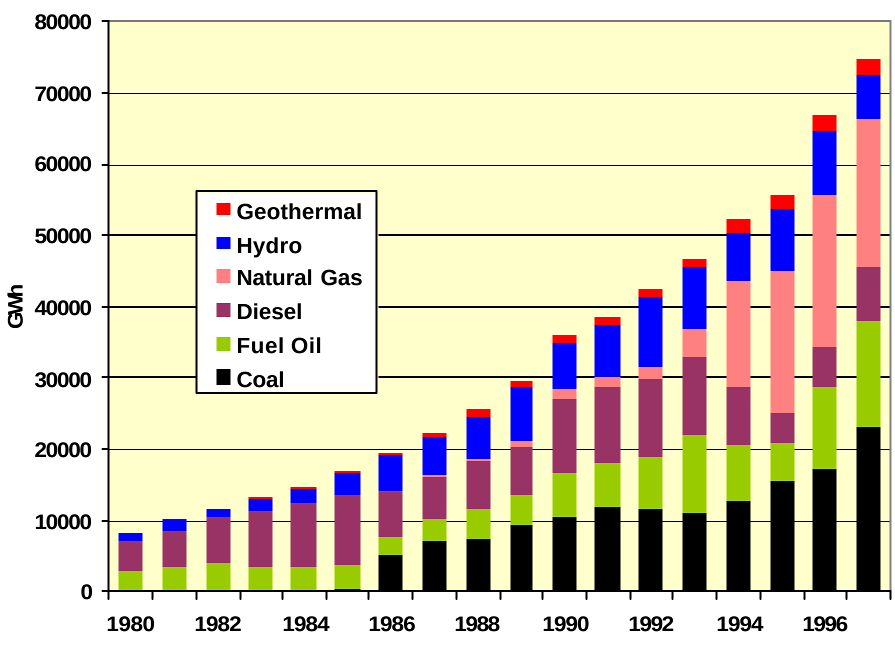
Indonesia is the world's fourth most populous nation, and electricity sector growth has occurred from a low base level of 8,420 GWh in 1980. Even today, only 57 percent of the Indonesian population (of around 213 million people) has access to electricity.

The Indonesian government has pursued an energy policy of fuel source diversification, hence growth in all power generation fuel types except diesel, which is an expensive power generation option, and tends to be used more in remote areas prior to extension of the transmission grid.

The primary energy sources in Indonesia are coal, biomass, crude oil (and refinery products), natural gas and geothermal. Natural gas, coal and LPG are used as feedstock in industrial processes, such as cement and fertiliser production [ALGAS, 1998]. Biomass, used mainly in the rural regions, is estimated to contribute about 35 percent of total energy consumption.

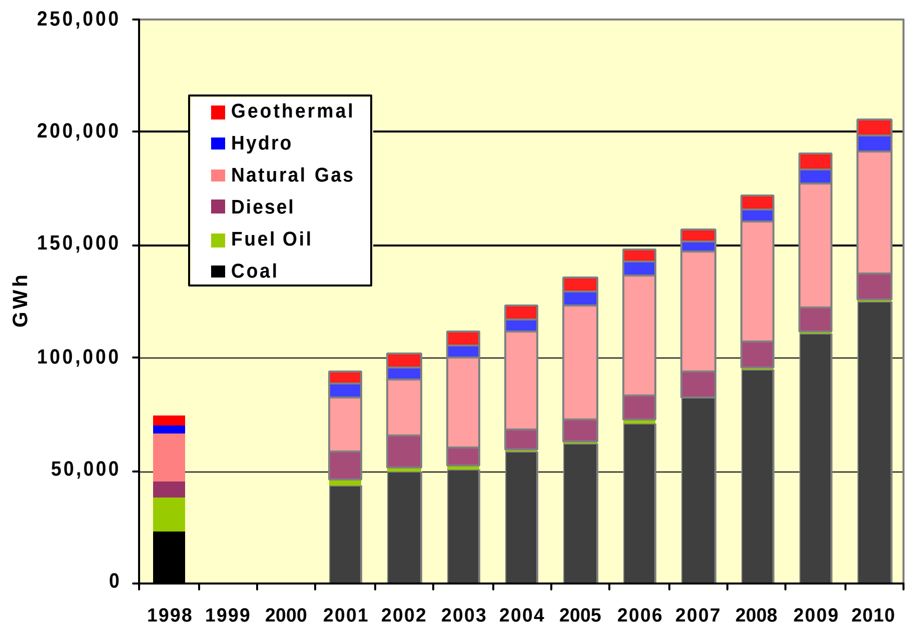
Figure 23 shows net power generation projections for Indonesia to 2010, and assumes an annual average growth in demand of 8.6 percent. As shown, the plan allows for large growth in coal-fired power generation (more than 5 fold increase over 1998), with more modest growth in natural gas-fired generation (2.6 fold increase over 1998). Net hydropower and geothermal generation levels are not projected to grow all that much in comparison. Diesel-fired generation remains significant because of the isolation of many communities from centralised power grids.

Figure 22 Net power generation by fuel type in Indonesia (1980-1997)



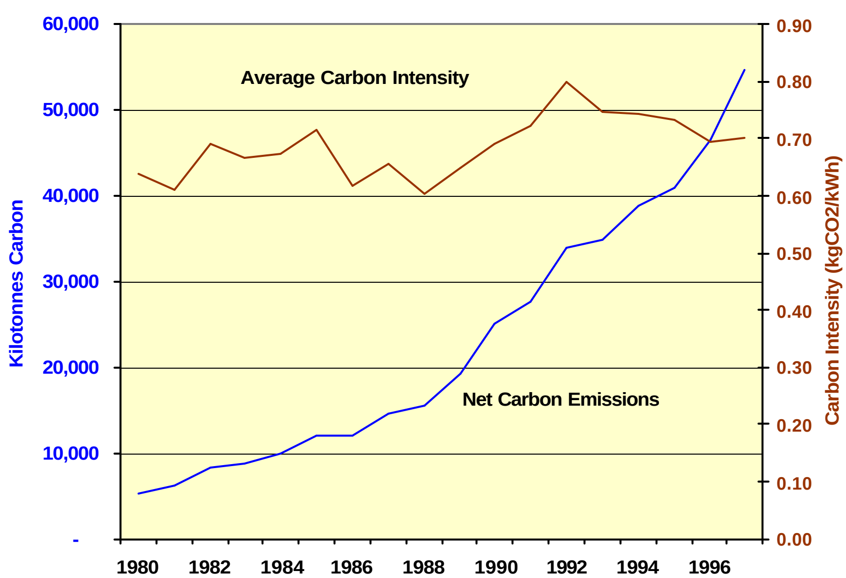
Source: EDMC and IEA databases

Figure 23 Projected net power generation by fuel type for Indonesia to 2010



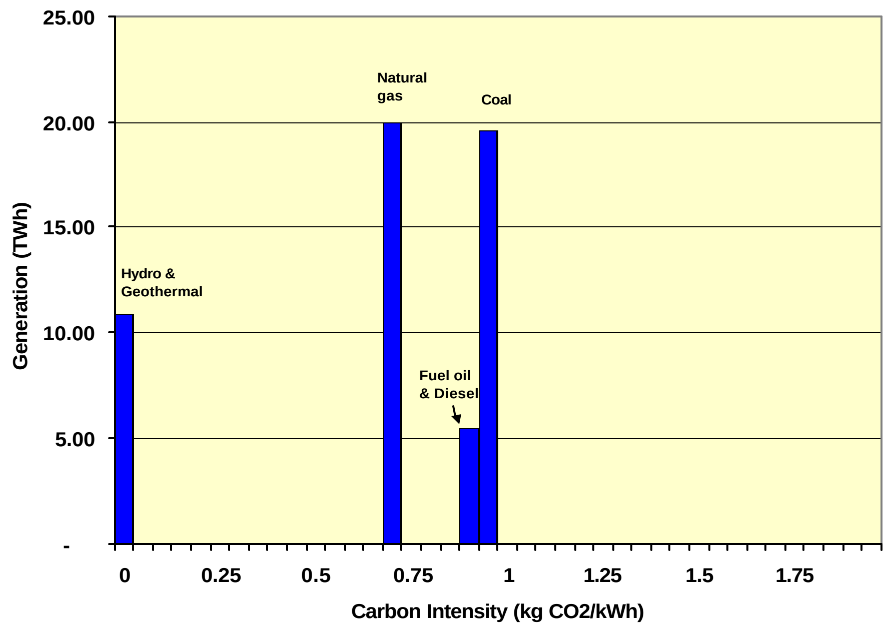
Source: Draft report of General Plan for National Electricity. Directorate General of Electricity and Energy Development. Indonesia.

Figure 24 Indonesia - net power sector carbon emissions & carbon intensity (1980-1997)



Source: EDMC and IEA databases

Figure 25 Carbon intensity baseline for the electricity sector in Indonesia for 1995



Source: EDMC and IEA databases

Figure 24 shows the growth in net carbon emissions and the general trend in average carbon intensity for the power generation sector in Indonesia. Net carbon emissions have grown exponentially over the last two decades, reflecting the growth in power generation and the increasing use of fossil fuels for this purpose. A general upward trend in average carbon intensity reflects primarily the relatively large increase in coal combustion.

Using the available yearly energy supply and demand data for Indonesia, it is possible to develop a sector-wide carbon intensity baseline for any specific year. In this instance, 1995 has been chosen as a suitable benchmark, as shown in Figure 25. This avoids the problems associated with 1997 (the year of the financial crisis), the most recent year for which data is readily available for all economies.

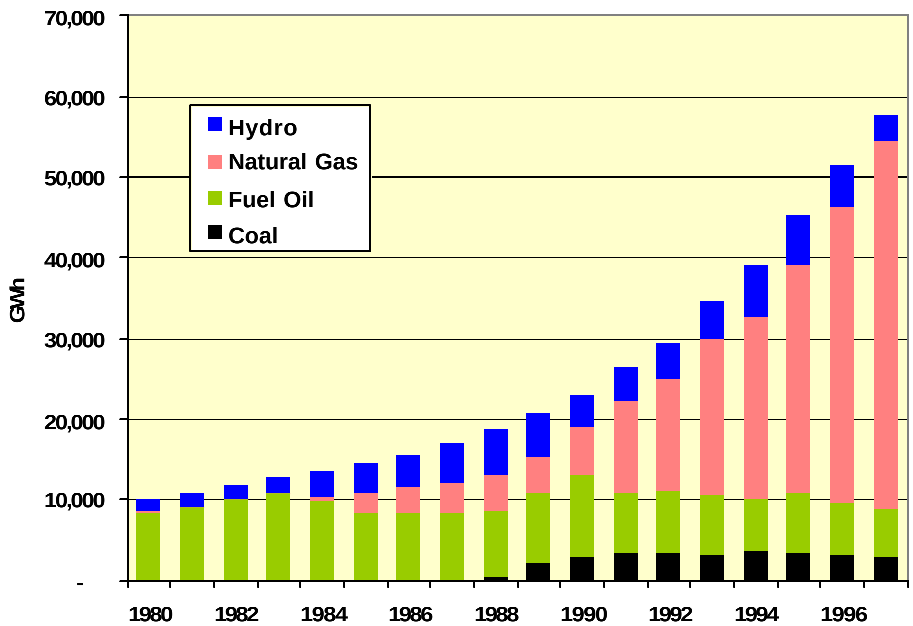
MALAYSIA

As with the economies so far considered, net power generation growth is impressive over the last two decades. As shown in Figure 26, net power generation in Malaysia averaged 10.8 percent per year for the period 1980 to 1997.

The Malaysian government has long seen electricity supply infrastructure growth as indispensable to economic development, and the fruits of this vision can be seen in the relatively high rate of electrification. As of 1997, 99 percent of Peninsula Malaysia was connected to the central power grid, and 75 percent of Sabah/Sarawak was electrified, mostly through grid connections, but with some remote village power systems.

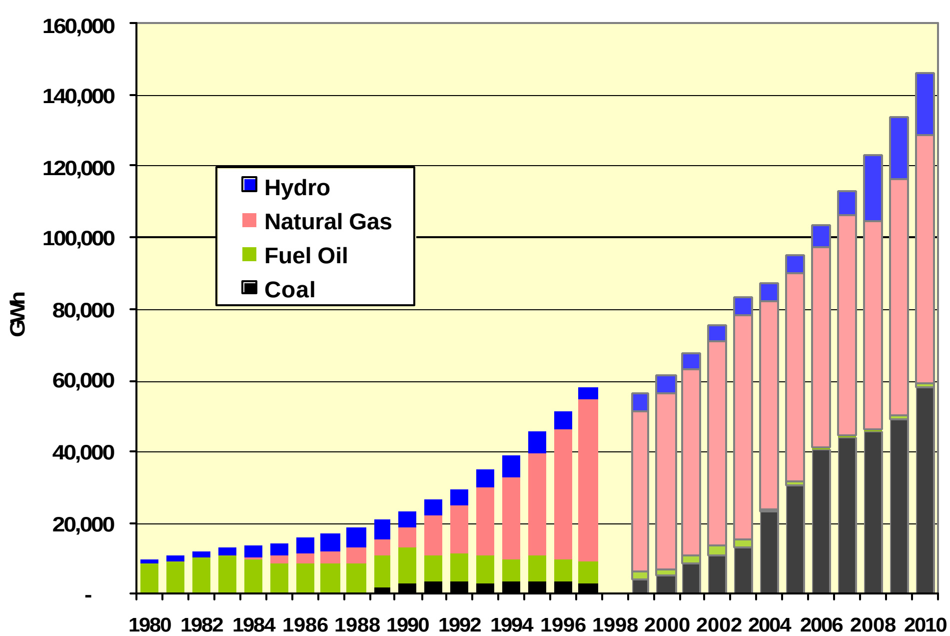
Since 1980, the Malaysian energy supply sector has been guided by the government's “four fuels diversification strategy.” This strategy grew out of the oil supply crisis in the 1970s, and the heavy

Figure 26 Net power generation by fuel type in Malaysia (1980-1997)



Source: EDMC and IEA databases

Figure 27 Historical and projected net power generation in Malaysia



Source: Projections modified from Thaddeus, 2000. Data for years 1980 to 1997 from APEC Energy Database.

dependence at that time on oil for most energy requirements, including transportation and power generation.

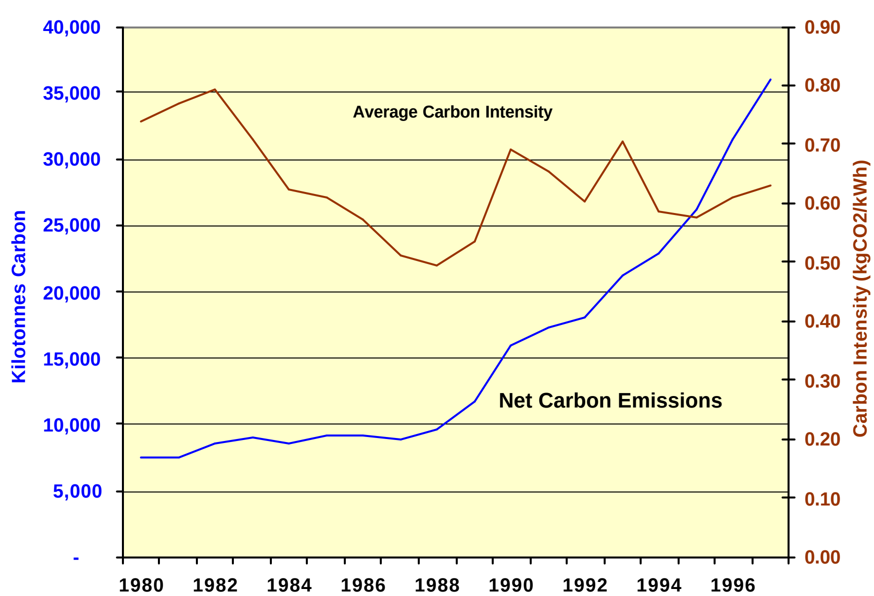
The four fuels are oil, natural gas, coal and hydropower. The government also has a policy (the Renewable Portfolio Standard), to increase the share of (non-hydro) renewable energy to 5 percent of total net generation by 2005. The additional renewable share is expected to come mainly from biomass co-generation, using wastes from the palm oil industry.

The influence the four fuels policy is likely to exert over future electricity supply growth decisions can be seen by referring to Figure 27. With coal relatively competitive as a power generation fuel, and energy fuel diversification an important government policy objective, coal consumption for power generation is set to grow from 4.2 million tonnes in 2000 to 13 million tonnes in 2005 as new coal-fired plants are commissioned over the next few years [Thaddeus, 2000]. The steam coal will be imported from Australia, Indonesia and China. Coal-fired generation could rival natural gas-fired generation by 2010.

Figure 28 shows the growth in net carbon emissions and the general trend in average carbon intensity for the power generation sector in Malaysia. As for other Asian economies, net carbon emissions have grown strongly over the last two decades, reflecting the growth in thermal power generation.

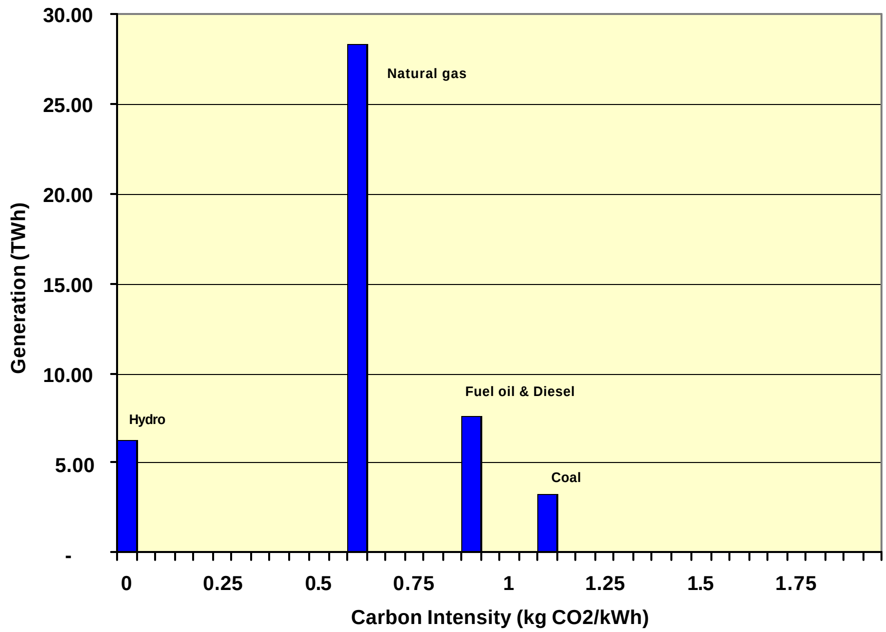
Average carbon intensity actually trended downwards from 1980 to 1997, reflecting the shift from fuel oil to gas. As coal-fired thermal generation comes on stream over the next few years, the average carbon intensity of the sector will rise accordingly. The carbon intensity baseline (Figure 29) reflects the importance of natural gas combined cycle power generation in the fuel mix.

Figure 28 Malaysia - power sector carbon emissions & carbon intensity (1980-1997)



Source: EDMC and IEA databases

Figure 29 Carbon intensity baseline for the electricity sector in Malaysia for 1995



Source: EDMC and IEA databases

PHILIPPINES

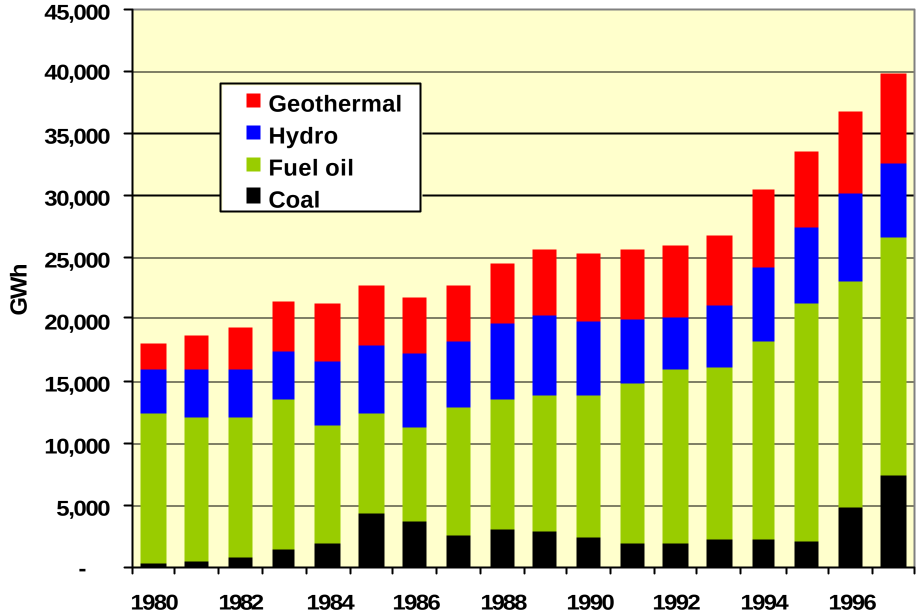
Net power generation growth over the last two decades in the Philippines has been less dramatic than that experienced in Thailand, Malaysia or Indonesia. As shown in Figure 30, net power generation in the Philippines averaged 4.8 percent per year for the period 1980 to 1997.

Where the Philippines differs from other Southeast Asian economies considered in this study is in the aggressive development of its large geothermal resource base. At the turn of the 20th century, installed geothermal capacity stands at 1,848 MW and the Philippines remains the world's second largest geothermal producer next to the United States.

The power sector has been heavily dependent on imported oil and oil products for many years. From 1971 to 1979, oil-based power generation comprised around 80 percent of total generation. As shown in Figure 30, fuel oil still accounts for nearly 50 percent of total net generation. The Philippines remains one of the few Asian economies still relying on fuel oil and other petroleum products for a significant percentage of power generation output. The Philippines stands alone as the only Asian economy where the use of petroleum-based products for this purpose has actually increased over the last decade.

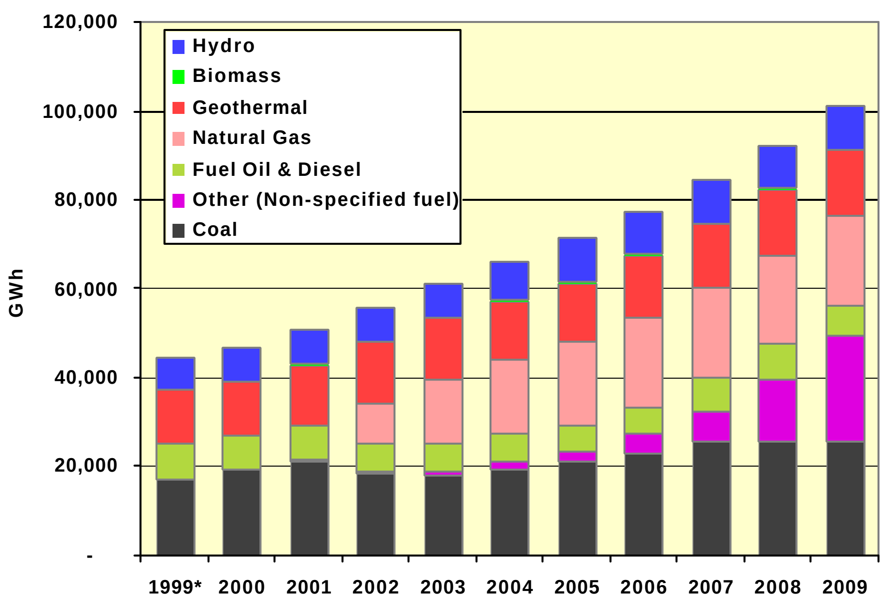
The Philippines has some areas of natural gas resource, located in northern Luzon (where a 3 MW pilot plant is in operation) and offshore from Palawan Island. However, the resource potential is not particularly large, is mostly in deep water, and is far from the main consumer market, so natural gas-fired power generation is not likely to play the same role in the Philippines as it has in other Southeast Asian economies. Imported LNG could compete with fuel oil to supply baseload and peaking load to Manila and perhaps Cebu, but fuel oil may remain an importance fuel source for power generation given the large number of islands and scattered population centres.

Figure 30 Net power generation by fuel type in the Philippines (1980-1997)



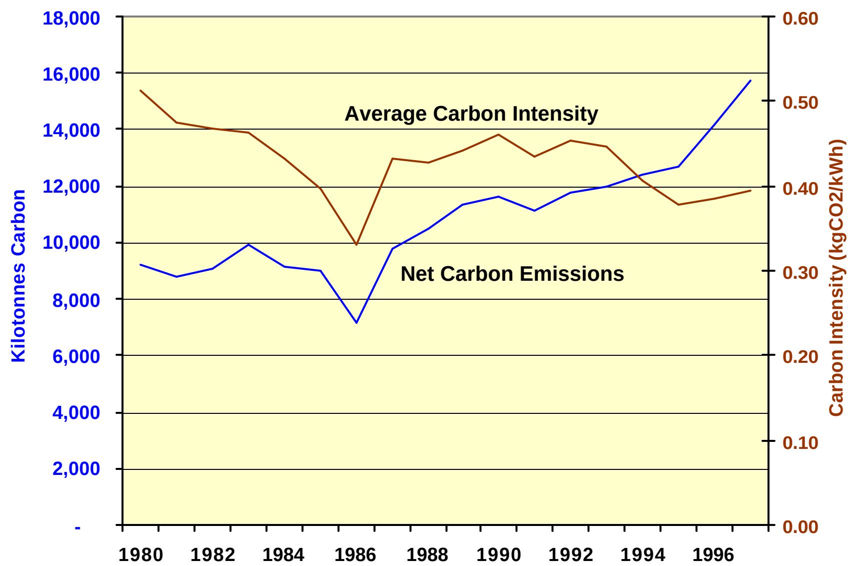
Source: EDMC and IEA databases

Figure 31 Historical and projected net power generation in the Philippines



Source: Philippine Energy Plan, 1999

Figure 32 Philippines - power sector carbon emissions & carbon intensity (1980-1997)



Source: EDMC and IEA databases

Net power generation projections from the most recent Philippine Energy Plan are shown in Figure 31. The projections assume an annual growth rate in net demand of 8.6 percent, a rate of growth consistent with net supply growth experienced over the course of the 1990s. Many of the power stations needed to meet this demand are in various stages of planning and construction, but some additional capacity will be needed over and above what is already in the pipeline.

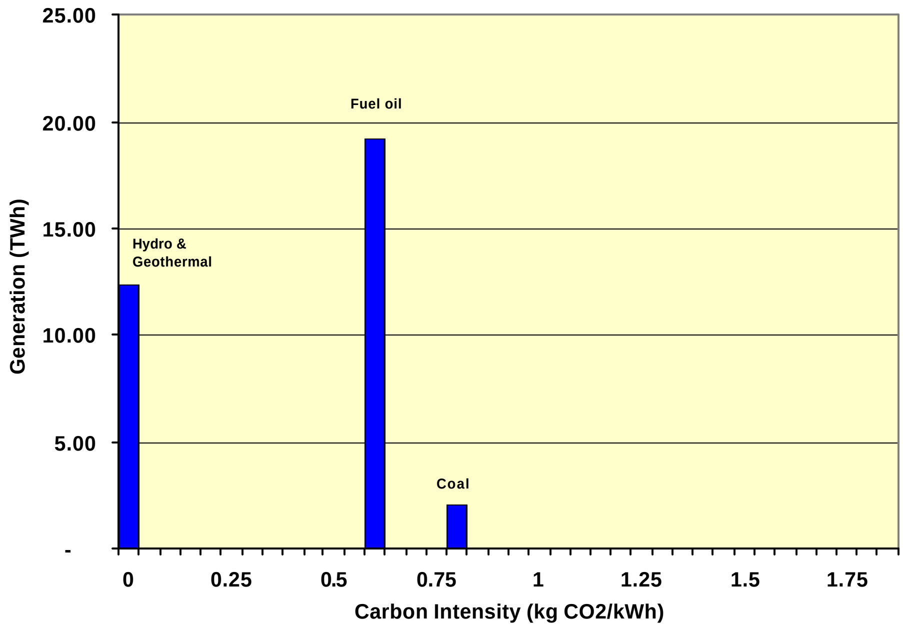
The Philippine Department of Energy is assuming that this additional supply capacity will be constructed by investors eager to invest in the Philippine energy scene after deregulation of the sector (scheduled to begin as soon as legislation is passed through Congress). Much of this capacity is shown in Figure 31 as of unspecified fuel type. The breakdown between baseload, mid-range and peaking plant for this unspecified capacity in 2009 is expected to be 54 percent, 34 percent, and 12 percent respectively. Peaking plant is likely to be fuel oil or perhaps natural gas. Other plants are likely to be a combination of coal, natural gas, geothermal and hydro. The extent to which natural gas contributes to total supply will depend on the success of ongoing exploratory drilling in the Palawan area.

Figure 32 shows the growth in net carbon emissions and the general trend in average carbon intensity for the power generation sector in the Philippines. There may be some problem with the data for 1986, but otherwise the general trend in average carbon intensity is downwards initially, reflecting the growth in importance of hydro and geothermal in the early 1980s, followed by relative stability as growth in demand is matched by growth in supply from all fuel types.

Net carbon emissions have grown less strongly over the last two decades than for other Southeast Asian economies, partly reflecting the growth in hydro and geothermal capacity, and partly reflecting the overall lower growth in net power generation.

A carbon intensity baseline is shown in Figure 33. The largest peak reflects the importance of fuel oil for power generation. It is unclear if there are data problems, but the carbon intensities calculated for fuel oil combustion in the Philippines are consistently lower than calculated for other Asian economies.

Figure 33 Carbon intensity baseline for the electricity sector in the Philippines for 1995



Source: EDMC and IEA databases

THAILAND

Net power generation in Thailand showed very rapid growth between 1980 and 1997, averaging 11.5 percent per year for the period (Figure 34). Thailand, lacking large-scale readily exploitable renewable resources such as hydro and geothermal, has focussed on natural gas development, along with increasing use of coal for power generation. By 1997, natural gas plants provided 47.4 percent of total net power generated. In contrast to the general trend in the region, fuel oil has remained an important power generation fuel in Thailand, with consumption actually trending upwards over time. This is set to change over the next five years, when the share of fuel oil and diesel used for net power generation is set to decline from 23.9 percent in 1997 to between 1 and 1.5 percent by 2005.

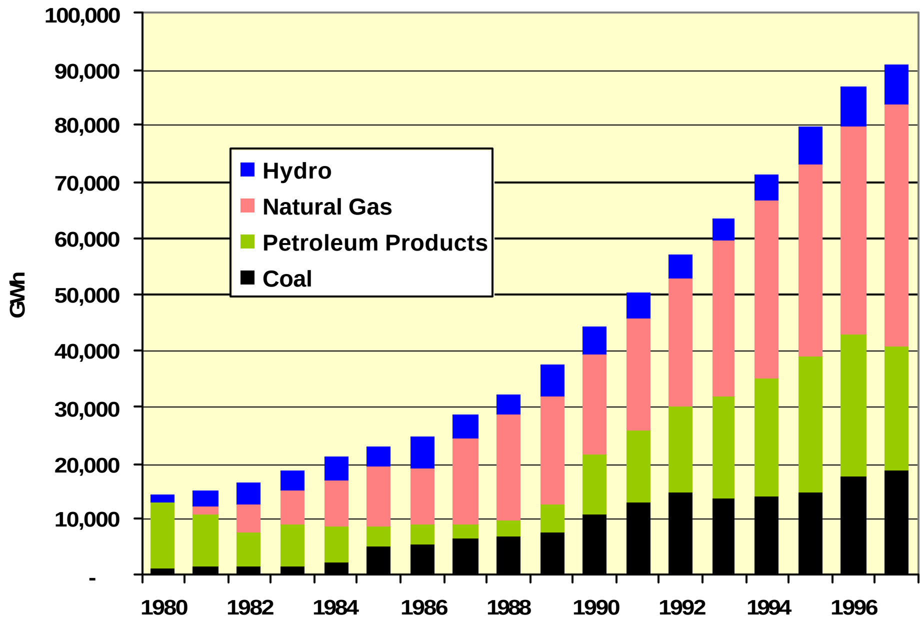
Figure 35 shows projections for installed power generation capacity to the year 2011 from Thailand's Department of Energy Development and Programmes. Use of indigenous lignite will not expand under this programme, the use of lignite now being actively discouraged because the environmental problems at the in Mae Moh power plant. Steam coal will be imported to provide for increased thermal power capacity.

ENERGY SECTOR GHG EMISSIONS

The Asia Least-cost Greenhouse Gas Abatement Strategy (ALGAS) project has developed a comprehensive database of GHG emissions for eleven Asian economies. GHG emissions from the energy sector were estimated from energy combustion and production activities, and from chemical reactions in energy transformation processes. The estimated quantities of CO_2 emitted by the energy sector by fuel type are shown in Table 9 and by sectors in Table 10.

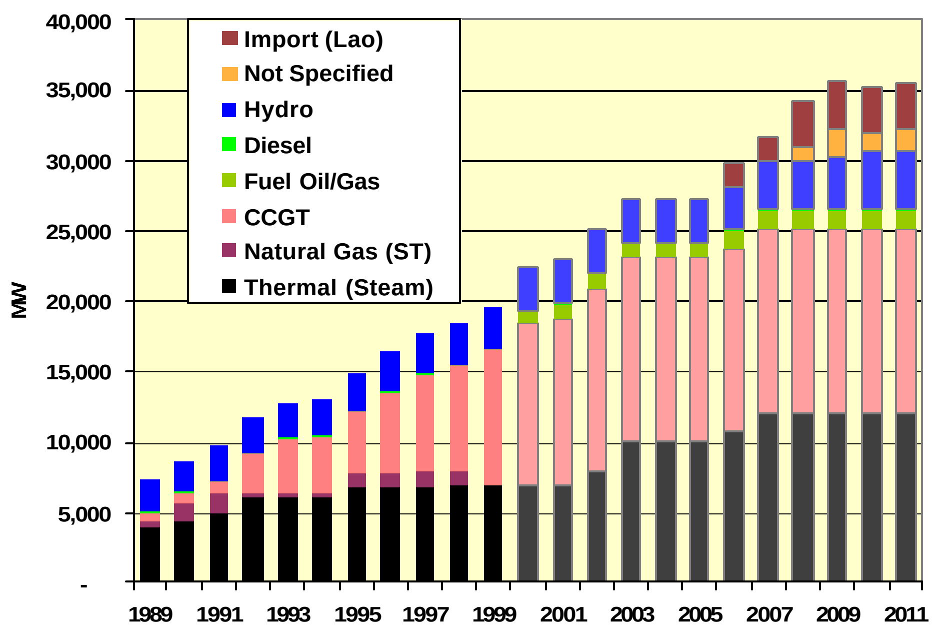
Total CO_2 emissions from combustion of all fuel types in 1994 were 181.03 million tonnes, to which power generation contributed 25 percent, or 45.26 million tonnes.

Figure 34 Net power generation by fuel type in Thailand (1980-1997)



Source: EDMC and IEA databases

Figure 35 Historical and projected power generation capacity in Thailand.



Source: Thailand's Department of Energy Development and Programmes. The data for thermal (steam) encompasses plants that can burn either coal or fuel oil.

Table 9 CO_2 emissions from fuel combustion by fuel type (1990-1994)

	CO_2 emissions in million tonnes				
Fuel Type	**1990**	**1991**	**1992**	**1993**	**1994**
Solid		15.64	18.03	18.99	21.76
Liquid		64.46	70.85	79.65	88.11
Gas		16.25	17.38	19.46	21.57
Total Fossil Fuel Emissions	76.73	96.35	106.26	118.1	131.44
Biomass		30.7	41.8	45.01	49.59
Overall Emissions	76.73	127.05	148.06	160.44	181.03

Source: Inventory data http://www.oepp.go.th, ALGAS (1998)

Figure 36 shows the growth in net carbon emissions and the general trend in average carbon intensity for the power generation sector in Thailand. Net carbon emissions have grown strongly over the last two decades, reflecting the growth in power generation and the increasing use of fossil fuels for this purpose. The trend shown in average carbon intensity probably reflects reasonably accurately the transition from a reliance on fuel oil in the late 70s and into the early 80s, to a reliance on natural gas (decreasing average carbon intensity), with an increasing trend of coal consumption in the 90s increasing average carbon intensity).

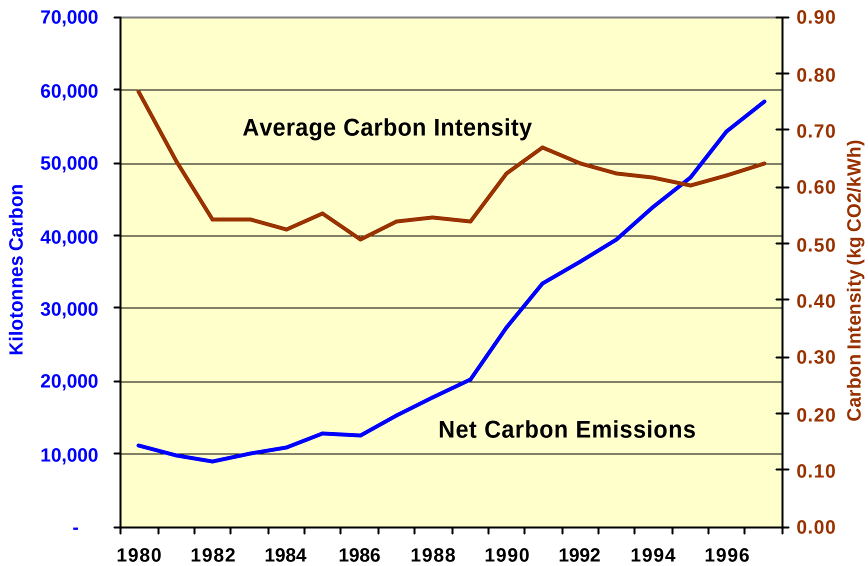
The carbon intensity baseline (Figure 37) differs from that for Indonesia in that natural gas combined cycle power generation has a substantially greater influence, with the carbon intensity about half that for coal, and lower than for fuel oil

Table 10 CO_2 emissions from fuel combustion by economic sector (1990-1994)

	CO_2 emissions in million tonnes			
Economic Sector	**1991**	**1992**	**1993**	**1994**
Industry	13.35	15.06	17.21	16.63
Power Generation	34.4	37.51	40.72	45.26
Transportation	36.09	38.32	44.22	49.56
Agriculture	5.63	5.83	4.97	4.85
Commerce & Residences	2.45	2.68	2.99	3.24
Total Fossil Fuel Emissions	91.92	99.41	110.1	119.53

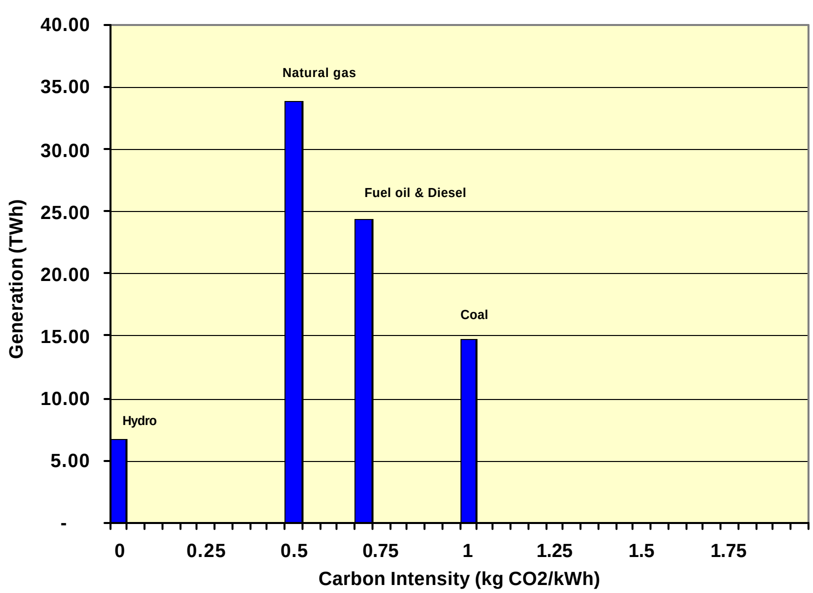
Source: ALGAS, 1998

Figure 36 Thailand - net power sector carbon emissions & carbon intensity (1980-1997)



Source: EDMC and IEA databases

Figure 37 Carbon intensity baseline for the electricity sector in Thailand for 1995



Source: EDMC and IEA databases

CHAPTER 7

CDM CASE STUDIES

INTRODUCTION

As well as the simulations reported in Chapter 4, this report includes three specific case studies for China, Indonesia and Thailand. In each case, a different project has been selected, in part to reflect the kind of economy-specific options that are available and also to reflect a range of potential electricity generation investment opportunities.

- The first case study looks at a wind power project in China.
- The second case study looks at a 300 MW natural gas combined cycle power project in Java-Bali replacing a coal-fired plant of similar capacity.
- The third case study looks at a co-firing electricity generation project in Thailand where biomass is used as supplemental fuel in a coal-fired power station.

The CDM project case studies in this report were modelled with COGEN,[19] an energy project assessment model developed by the Lawrence Berkley National Laboratory (see page 30). COGEN allows consideration of two aspects of a project - environmental assessment and financial assessment. Originally it was designed to assess the feasibility of renewable energy or energy efficiency improvements against conventional technologies. For the purposes of our research, the COGEN model was modified and somewhat simplified to allow project assessment of the above case study projects.

CHINA

China has placed a high priority on dealing with existing pollution problems, as well as working towards measurable improvements in local and regional environmental quality. China signed the United Nations Framework Convention on Climate Change (UNFCCC) in Brazil in 1992 and adopted Agenda 21 as the framework for a sustainable development strategy.

As the largest developing economy in Asia, China has a very large potential for CDM projects. A number of AIJ projects have been undertaken with Japan and the Netherlands since 1995. China also participated in an Asia Least-Cost Greenhouse Gas Abatement Strategy (ALGAS) project, which was supported by the ADB, UN, and Global Environment Facility (GEF).

GHG EMISSIONS

The total net CO_2 equivalent emissions were in the range of 2361.6 to 2624.5 million tonnes in 1990. Energy consumption and industrial sectors contributed more than 60 percent of total GHG emissions. The agricultural sector was the major source of methane emissions. It is estimated that China accounts for about 9 percent of global fossil-energy related CO_2 emissions [ALGAS, 1998].

Table 11 China's national greenhouse gas inventory in 1990

Source and Sink	CO_2 Emission	CO_2 Removals	Net CO_2	CH_4	N_2O	CO_2 Equivalent	Percent of Total CO_2 Equivalent
				Thousand tonnes			
Total (Net) National emissions	2271528	501966	1769562	25389-32889	190-530	2361626-2624526	100
I: All energy	2004107		2004107	11900	120-130	2291204-2407029	97.0-89.9
A: Fuel combustion	2004107		2004107	3034	120-130	2105011-2173221	89.1-92.8
1: Energy and transformation industries	637712		637712	62	120-340	676218-744414	28.6-28.4
2: Industry	834048		834048			834048	35.3-31.8
3: Transport	113447		113447			113447	4.8-4.3
4: Commercial-Institutional	17839		17839			17839	0.8-0.7
5: Residential	288539		288539			288539	12.2-11.0
6: Traditional biomass	641248		641248	2971		62397	2.6-2.4
7: Others	112523		112523			112523	4.8-4.3
B: Fugitive fuel emission				8866		186194	7.9-7.1
1: Oil and natural gas system				92		1929	0.1-0.1
2: Coal mining				8775		184265	7.8-7.0
II: Industrial Processes	93988		93988			93988	4.0-3.6
A: Cement production	78588		78588			78588	3.3-3.0
B: Others	15400		15400			15400	0.7-0.6
Iron & steel	15400		15400			15400	0.7-0.6
III: Agriculture				12590-20090	70-190	286090-480790	12.1-18.3
A: Enteric fermentation				2379-6671		49959-140091	2.1-5.3
B: Manure management				550-771		11550-16191	0.5-0.6
C: Rice cultivation				9661-12648		202881-265608	8.6-10.1
D: Agriculture soils							
E: Prescribed burning of savannas							
F: Field burning of agricultural residues					10-30	3100-9300	0.1-0.4
G: Others:					60-160	18600-49600	0.8-1.9
1: Agriculture waste							
2: Fertilizer use					10-30	3100-9300	0.1-0.4
3: Other					50-130	15500-40300	0.7-1.5
IV: Land-use change and forestry	173433	501966	-328533			-328533	-1.4
A: Changes in forest & other woody biomass stocks		406267	-406267			-406267	-1.7
B: Forest and grassland conversion							
C: Abandonment of management lands		8433	-8433			-8433	-0.1
D: Other	173433	87266	86167			86167	3.6-3.3
1: Forest biomass burning	94233		94233			94233	4.0-3.6
2: Decomposition	79200		79200			79200	3.4-3.0
3: Soil carbon		31533	-31533			-31533	-0.1
4: Agro forestry		55733	-55733			-55733	-0.3
V: Waste				899		18877	0.8-0.7
A: Solid waste disposal on land				899		18877	0.8-0.7
B: Waste treatment							
C: Others							

Source: ADB, GEF, UNDP, AlGAS of China, 1998

Note: CO_2 emissions from traditional biomass burning are not included in subtotals and the national total.

POTENTIAL FOR GHG EMISSIONS REDUCTION PROJECT

China is the largest coal consumer in the world while fuel combustion contributed around 90 percent of GHG emissions. On this basis, it is clear that efforts to control or reduce coal consumption represent the greatest GHG emission reduction potential.

Coal consumption in China reached 1447.3 million tonnes in 1996 (a historical high point) and began to decline thereafter. The reasons for the fall in demand can be explained by energy efficiency improvements and energy substitution in the residential sector, with LPG replacing coal for cooking and heating.

Table 12 shows coal consumption by sector. Electricity generation and the industry sector dominate, accounting for more than 90 percent of coal consumption in 1997. Coal consumption in residential and transport sectors has declined significantly over the period shown. Projected coal demand remains in a growth trend, but the share of total primary energy will decline over time.

Table 12 Coal consumption by sector in China

	Electricity Generation	Residential	Transport	Industry and Others
1985	22.09%	22.82%	3.49%	51.60%
1987	23.54%	23.10%	2.90%	50.46%
1989	25.31%	19.56%	2.27%	52.86%
1991	28.54%	17.70%	2.05%	51.71%
1993	32.28%	12.96%	1.64%	53.12%
1995	32.28%	9.83%	0.96%	56.93%
1997	35.20%	8.79%	1.03%	54.98%

Source: SPDC, 1997. *Energy Report of China*.
China Energy Statistical Yearbook 1991-1996, 1998.
China Statistical Yearbook 1999, 1999.

LAW, REGULATION, AND POLICIES RELEVANT TO CDM

LEGAL ENVIRONMENT IN CHINA FOR CDM

China initially became aware of serious environmental issues in early 1970s and enacted the “Environment Protection Law” in 1979. Environmental protection became a national objective after the Sixth Five-Year Plan (1981-1985). China has focused on reducing the emissions of polluting substances as well as GHG emissions. The main laws include the “Environmental Projection Law,” the “Water Pollution Prevention Law,” the “Air Pollution Prevention Law,” the “Solid Pollutants Pollution Prevention Law,” the “Noise Pollution Prevention Law,” and the “Marine Environmental Protection Law.” Other related laws covering land use, forestry, green areas (grass), and minerals, have also formulated.

The Chinese government published the *Foreign Investment Project Guide* in 1997, providing government guidelines and policies on foreign direct investment. Projects with foreign funding support are eligible for certain incentives such as lower import duties. Local governments also have incentive policies, like lower local taxes or lower land purchasing prices, with the aim of promoting investments in environmentally friendly projects.

China has aggressively participated in international cooperation on the environment, and signed bilateral and multilateral agreements and protocols with more than 20 economies.

TECHNICAL AND ENVIRONMENTAL STANDARDS

Central and local governments have established technical standards for industrial projects and occa-

Table 13 Selected environmental protection regulations, policies, and plans for China

Name	Approved Institution	Time	Main Contents
China's Ten Measures for Environment and Development	The Central Committee of the Chinese Communist Party The State Council	1992.8	The fundamental references for environment and development
China Environmental Protection Strategy	The State Planning Committee The State Environmental Protection Bureau	1992	Environment protection strategies
China's Environmental Protection Plan (1991-2000)	The State Council	1993.9	Economy-wide regional plan
China's Agenda 21	The State Council	1994.3	The write paper for population, environment and development
Urban Environmental management Study	The State Environmental Protection Bureau The Construction Ministry	1994	Polluted water and rubbish management study
GHG Emissions and Control Issue and Measures	The State Planning Committee The State Environmental Protection Bureau	1994	The current GHG emissions situation, least cost analysis and recommended measure
China's Environmental Protection Agenda 21	The State Environmental Protection Bureau	1994	Agenda 21 for ministry level
China's Forestry Agenda 21	The Ministry of Forestry	1995	Agenda 21 for ministry level
The Ninth-Five Year Plan for China's National Social and Economic Development and Long-Term plan for 2010	The People Congress	1996.3	Environmental protection and sustainable development were adopted as the national objectives. Propose environmental projection targets for 2000 and 2010.
China's Marine Agenda 21	The State Marine Bureau	1996.4	Agenda 21 for ministry level
The Ninth-Five Year Plan for Environmental Projection and Long-Term Development Framework	The State Council	1996.9	The fundamental references for environment and development
China's Green Engineering Plan	The State Council	1996.9	Propose Environmental Projects

Source: Bao Qiang, 1998

sionally modify standards to improve project performance. China has formulated a "Pollutant Emissions Total Quality Control Plan" aiming to maintain pollutant emissions in the year 2000 at 1995 levels. The major standards are listed in Table 14. Greenhouse gases are not included in the control plan.

Table 14 Emissions standards planned for China (for year 2000)

	1995 emissions				Planned Standards
Major Pollutants	County Level	Town	Residential	Total	
Smoke and dust	8069	8067	347.5	16513.5	16500
Industrial dust	5827	10554.3		16381.3	16380
SO2	14252.8	6159.1	2758.2	23412.3	23400
Petroleum	65.765	23.519		89.284	86.28
Arsenic	1.124	0.363		1.487	1.485
Mercury	0.017	0.013		0.03	0.029
Lead	1.37	0.437		1.807	1.8
Cadmium	0.173	0.077		0.25	0.25
Chromium	0.415	0.336		0.751	0.75
Industrial solid rubbish	23194	41569		64763	64700

Source: Bao Qiang, 1998

An important question is when China will invoke laws and/or regulations governing carbon emissions. This is not an easy question to answer - current standards tend to promote greater energy consumption, which will tend to result in more carbon emissions.

PROJECT APPROVAL PROCESS

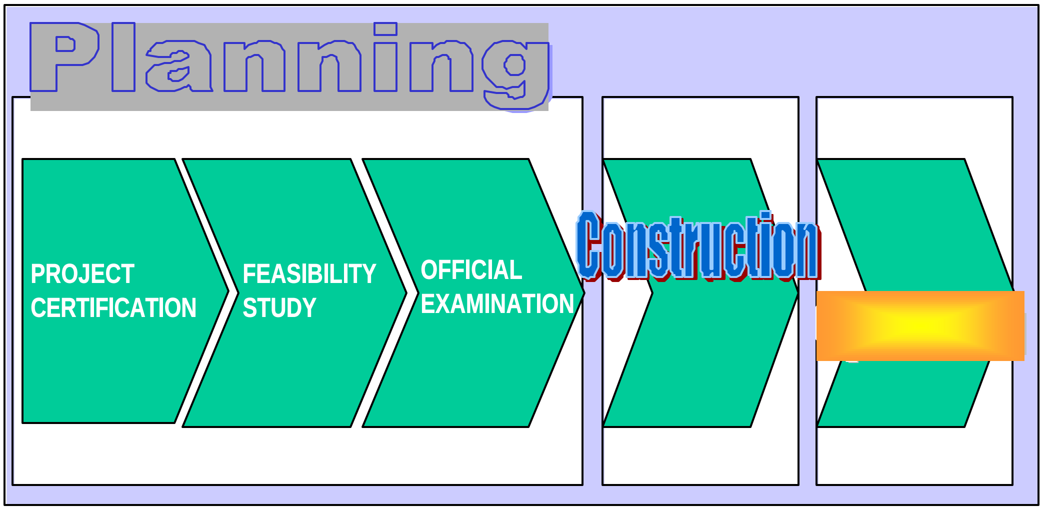
China is in a state of economic transition, and project implementation procedures are likely to be subject to change over time. Traditionally, construction projects were included in the State Long-Term Plan and Five-Year Plan. The basic procedure is demonstrated below in Figure 38 [SDPC, 1995].

PROJECT IMPLEMENTATION PROGRESS

Project implementation consists of three stages, the early planning stage, construction, and finally the operation stage. In the planning stage, there is a project certification phase, a project feasibility study phase, and an official examination phase. A project certification report presents basic background project information, such as the resource situation, suitable technologies, market evaluation, and potential investors. Detailed project design is undertaken in the feasibility study period. The project must obtain permission from State or Local Environment Bureaus, according to the scale of the project. The investors must sign agreements related to capital guarantees.

The project certification examination focuses on whether the project is keeping with state industrial development policies. When the necessary implementation conditions have been met and official per-

Figure 38 Construction project implementation phases in China



mission granted, the project can begin construction.

Investors are then left to organize project construction independently, with the government acting to assist with problems encountered during the construction period.

PROJECT DECISION MAKING PROCEDURES

Project decision-making in China involves a step-by-step examination system. Departments with varying responsibilities have the authority to examine projects, based on the scale of the project. For large-scale projects, investors propose projects to the Local Planning Committee (LPC) or relevant Ministry. After initial examination, LPC or the Ministry will propose projects to the State Development & Planning Committee (SDPC). After examination by SDPC, projects will be proposed to the State Council for final permission. For medium or small-scale projects, the process is less rigorous and it will be dealt with entirely by the appropriate agency (SDPC, LPC, or relevant Ministry).

All three planning phases follow this procedure. For foreign direct investment projects, just the project certification and feasibility study need to be examined.

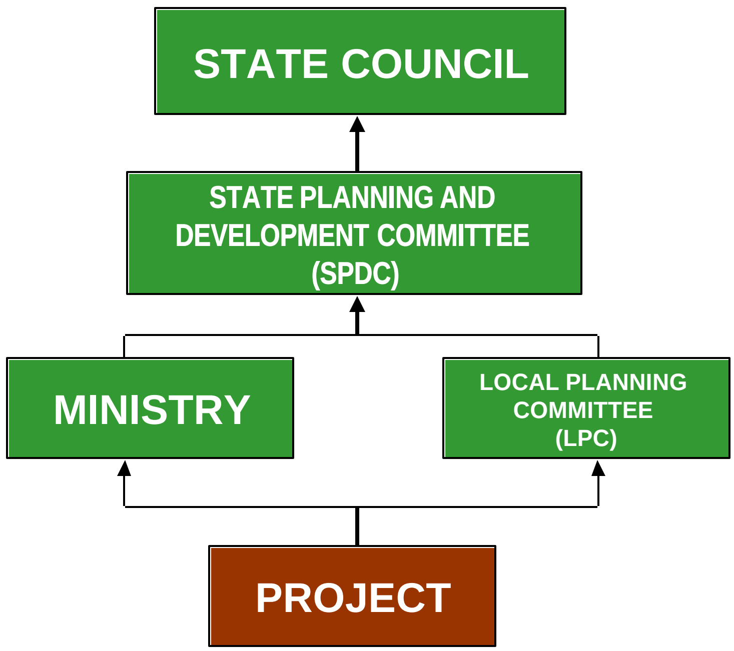
PROJECT SCALE STANDARDS

A large-scale project is defined as one with an investment level of more than 100 million RMB.

The current project approval procedure is a complicated, time-consuming process, and reform of this procedure has been strongly suggested. The Chinese government has been aware of the need to reform investment processes, in line with overall economic reform, and has tried to simplify approval procedures where the project circumstances demand. However, large-scale changes in such processes take time to be fully accepted and adopted.

For potential CDM projects in China, the transaction costs involved in the decision-making procedure may be too large to attract investors.

Figure 39 Decision making procedure for large-scale projects in China



A POTENTIAL CDM PROJECT

The CDM project chosen for this study is a wind power plant. As China is heavily reliant on coal for power generation sector, fuel substitution projects present ideal opportunities for CDM investment. The case study project is a wind power plant replacing an existing commercial coal-fired power plant with the same capacity. The purpose of this study is to model the relationship between electricity prices, carbon credits and incentive policy impacts, rather than calculate the exact number of credits such a project would generate. Many factors, such as the price of equipment, construction period, operational and maintenance practices and costs, and fuel quality, could totally change the conclusions. For that reason, the data used here is from average statistics and the parameters somewhat idealised.

PROJECT INFORMATION

The basic information used in the modelling exercise is provided in Table 3. The project's environmental as well as financial feasibility is compared against a coal-fired generation unit with 25 percent thermal efficiency. The generation output of the coal unit is replaced by an equivalent amount of wind power generation. The three carbon prices used in Chapter 4 are applied here.

The result from COGEN model run is provided in Figure 40. The IRR before tax and after tax are modelled separately. The results indicate that a wind power plant project using the input data used here would not be commercially viable under normal conditions unless the carbon credit price is high. The high capital investment cost and low capacity factor are the major reasons for poor financial performance.

Tax exemption can improve project performance significantly. For instance, taking the high carbon credit price cases, IRR increases from 3.9 percent to 6.0 percent when 20 percent income tax is exempted.

Table 15 Basic assumptions for wind power generation unit replacement project

Installed Capacity	10,000(kW)	Electricity Price	US$ 0.057/kWh	Income Tax Rate	20%
Capacity Factor	22%	Monitoring Cost	US$ 30,000/year		
Capital Investment	US$ 1,000/kW	O&M Cost	US$ 0.01/kWh		

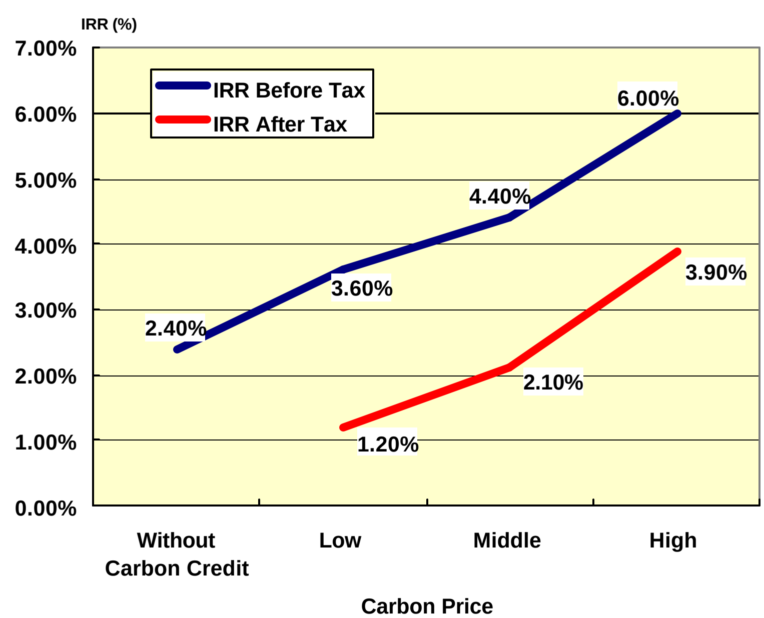
Note: Cost Assumptions are taken from NEA/IEA. Electricity price assumptions are based on CPIC data. Monitoring cost is estimated by APERC.

China has abundant wind resources in the north and west regions, and along the coast. The Chinese government already has a policy of encouraging the development of wind power (for both on-grid and off-grid applications), and such developments would offset planned coal-fired generation capacity. To encourage foreign partners in a wind power project, it may be necessary for the Chinese government of offer tax breaks, and/or other incentives such as subsidies. Under those conditions, large-scale investment in wind power in China could be envisaged.

CONCLUSIONS

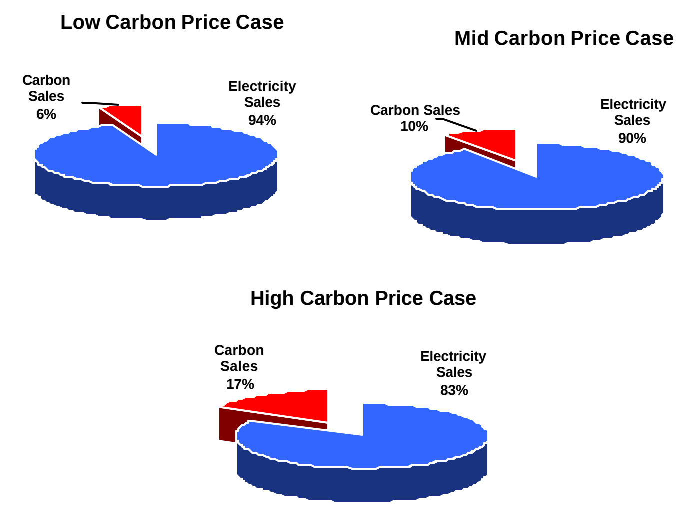
Environmental issues, including the potential climate change impacts of greenhouse gas emissions, are attracting increasing attention in China. The legal system has adapted to the idea of promoting environmentally friendly projects implementation, and further policy measures can be expected. Government efforts to improve the environment present a significant opportunity for projects. As coal

Figure 40 IRR for wind unit replacement project (China)



Note: Average electricity production per year is estimated at 19,272MWh. Total carbon emissions avoided over the project period are estimated at 65,319 ton-C

Figure 41 Share of carbon and electricity sales to gross revenue (China)



the main energy resource used currently in China, there is excellent potential in the power generation and industrial sectors for CDM projects. Fuel substitution and technology upgrades are logical areas to consider. Financial incentives, such as tax breaks and low interest loans, can improve the potential profitability of projects.

INDONESIA

National energy policy favours the use of locally available energy resources for domestic energy requirements, as well as promoting the use of renewables such as hydro, geothermal and biomass. The availability of hydro, biomass and geothermal resources suggest other CDM options, however these resources tend to exist in the more remote areas, requiring long distance transmission lines to markets. In addition, many of the potentially exploitable hydro and geothermal resources are located in forestry preservation areas.

Another problem with geothermal development is that this option is less competitive than coal and natural gas options. Coal and gas have lower power development costs (US$ 1,268/kW and US$ 668 kW respectively). To reduce the price of electricity from geothermal plants, tax subsidies in the form of income tax reduction, investment tax credits or tax holidays are required.

With respect to demand projections, the share of coal used for power generation is likely to be substantially higher in future (ALGAS, 1997). Most of the IPP projects approved by the government for construction in the near future are coal-fired plants, including some government (PLN) projects, such as the Asam-Asam plant in Kalimantan and the Tarahan plant in Sumatra. According to current environmental policy, the construction of new coal-fired capacity will not be permitted on Java Island beyond 2010, additional demand will be met with electricity transmitted from outside Java.

ENVIRONMENTAL POLICY

Indonesia, having ratified the United Nations Framework Convention on Climate Change,[20] has incorporated the implications of greenhouse gas emissions into its energy policy framework, along with regulations dealing with the local environment such as environmental impact analysis and land-use management procedures.

In recent years, Indonesia has taken action to reduce the role of central government in regional decision-making, including in the area of environmental policy. The Government of Indonesia is currently proposing guidelines at the central and regional levels to achieve this policy goal. The constraints to effective implementation of these plans include a general lack of financial resources and a lack of technically trained people to action and monitor regional regulations.

The two important environmental laws are the 1997 Law No. 22 concerning the granting of regional autonomy and the 1999 Law No. 25 setting out fiscal responsibilities for management of natural resources and the environment.

INSTITUTIONAL ISSUES

At this stage, it is still uncertain where the balance of power will lie between central and regional governments, but the following institutions are currently composing the basic rules for environmental management in Indonesia.

- The Office of the Minister of State for the Environment (KLH), established in 1978, oversees environmental policy including coordination of the activities of all government agencies. KLH does not have directly responsibly for implementing environmental policies however.

- The Environmental Impact Management Agency (BAPEDAL), established in 1990, is responsible for preventing and controlling environmental impacts. BAPEDAL also has responsibility for enforcing environmental regulations. Both BAPEDAL and KLH develop pollution control and other standards.

- The National Development Planning Agency (BAPPENAS) has the task of developing guidelines and a national budget for poverty eradication. The Regional Development Planning Agency (BAPPEDA) has responsibility for preparing a plan for regional land-use management (but has power to implement the plan).

- The Ministry of Industry and Trade (DEPERINDAG) has the task of encouraging investment growth and improving commodity exports. This agency provides industry with licenses, including those covering land-use management. Another responsibility is the provision of eco-labelling.

TECHNICAL AND ENVIRONMENTAL STANDARDS

Based on a 1995 Minister of State for the Environment regulation, emission standards for coal-fired power plants will be tightly controlled from the year 2000, as shown in Table 16.

All major power projects are required to go through an environmental impact assessment process, except for transmission lines of less than 150 kV. Also exempted are diesel, fuel oil, and natural gas plants with a capacity of less than 100MW. Hydropower plants are exempted if the penstocks are less than 15 metres below the water level and the reservoir covers less than 200 hectares. Geothermal plants of less than 55 MW capacity are also exempt.

PROJECT APPROVAL

On the basis of current Indonesian regulation (2000 Presidential decree no. 12) all infrastructure proj-

Table 16 Post-2000 power station smokestack emission limits for Indonesia

Parameter	Maximum Limit (mg/m^3)
Total particulates	150
Sulphur dioxide (SO_2)	750
Nitrogen oxides	850
Opacity	20%

ects go through a competitive bidding process. Private participation in the power sector is required to meet demand growth expectations and a government-sponsored scheme exists to promote this, through a selection and bidding process conducted by the Ministry of Energy and Mineral Resources (MEMR), as shown in Figure 42.

The development of power sector infrastructure involves the Infrastructure Development Agency (*Badan Penetapan dan Pengendalian Penyediaan Prasarana dan Sarana Pekerjaan Umum*, BP4S-PU). The Ministry of Energy and Mineral Resources (MEMR) defines a project list, and proposes potential projects to BP4S-PU. Proposed projects should include a pre-feasibility study, a financial plan, the source of finance, and an explanation of the scope of cooperation (with timetable and evaluation criteria).

BP4S-PU will also match proposed plans against relevant sectoral and regional development plans to ensure compatibility with other projects listed in the list of Infrastructure Development Projects (DPKPI). The list of projects is published and is updated regularly.

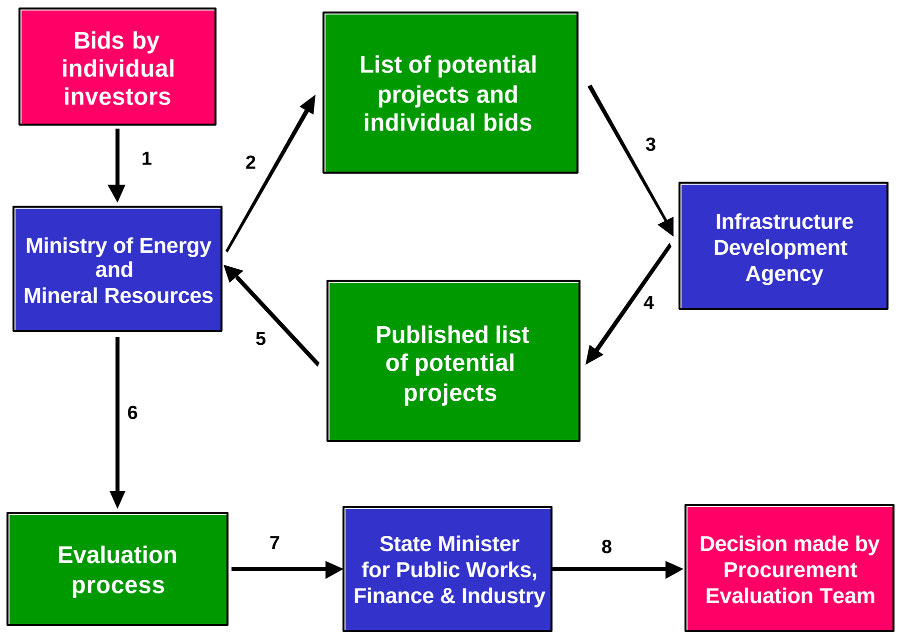
Based on the published lists the MEMR undertakes a project pre-qualification process. The criteria

Table 17 Electricity infrastructure investment program for Indonesia

		1999		2000		2001		2002	
		Million US$							
		FC	LC	FC	LC	FC	LC	FC	LC
Transmission	Java	156.7	55.7	51.8	11.1			10.6	7.4
	Other Islands	196.9	40.6	65.6	8.1			18.4	1.9
Sub Station	Java	55.8	15.5	18.3	3.1			5.5	2.8
	Non Java	186.4	16.48	62.1	3.3			52.9	10.6
Distribution	Java	32.9	8.1	45.9	12	57.2	15.9	81.0	22.9
	Non Java	37.4	9.3	56.1	14.7	62.2	16.7	83.8	23.1
Generation	Java			1.4	0.3				
	Non Java			279.3	149.6	143.0	85.4	127.0	63.6

Source: PLN's Long Term Planning Plan: 1999-2002
Notes: FC = Fast growth case. LC = Low growth case.

Figure 42 Procedure for approval of power plant projects



include: 1) the experience and performance of the company in similar projects; 2) financial capability, including experts and equipment; 3) liquidity, ability to meet tax obligations, and understanding of all regulations and laws that apply; and 4) ability to conform with other technical criteria of the MEMR.

The evaluation process follows pre-qualification, and looks at the financial aspects of the bid, as well as considering the technical ability of the company to build and operate the plant. Finally, the MEMR submits the bidding results to the State Minister for Public Works, Finance and Industry, as head of the Procurement Evaluation Team, which makes the final decision.

GREENHOUSE GAS EMISSIONS INVENTORY

Total national emissions of greenhouse gases in 1994 were estimated to be around 209 million tonnes. CO_2 is the dominant greenhouse gas, contributing about 63 percent of total emissions, as shown in Table 18. The second largest contributor is NOx, representing about 33 percent of the total. CO_2 emissions originate largely from combustion processes in various sectors, the most important being the transportation sector, followed by industry, solid fuel transformation and power generation.

A POTENTIAL CDM PROJECT

The case study project is a CCGT generation unit replacing an existing commercial coal-fired power plant with the same capacity. As it was mentioned in the previous section, purpose of this study is to model the relationship between electricity prices, carbon credits and incentive policy impacts, rather than calculate the exact number of credits such a project would generate.

PROJECT INFORMATION

The basic information of CCGT generation unit replacement project is provided in Table 19. This

Table 18 National greenhouse gas inventory for Indonesia (1994)

Green house Gas Sources and sink Categories	CO_2 emissions	CH_4	N_2O	NO_x	CO	NMVOC
	Thousand Tonnes					
Total national emissions	209,380.34	324	3.52	418.13	39.81	0.082
1. All energy (fuel combustion + fugitive)	187,979.33	324	3.52	418.13	39.81	0.082
Fuel combustion	187,979.33	2.91	3.52	418.13	39.81	0.082
Energy & transformation industry	73,455.38	0.21	0.098	330.08	18.49	n.a
Electricity and heat production	31,823.99	0.15	0.098	170.17	7.146	-
Petroleum refining	9,341.86	0.0022	0.00001	5.37	0.385	0.00093
Solid Fuel transformation & other energy Industry	32,289.53	0.058	0.00058	154.53	10.963	0.000046
Transport	44,415.96	1.14	3.42	71.18	16.67	n.a
Residential & commercial combustion	47,088.81	0.006	0.0026	0.31	0.46	0.082
Fugitive emissions from fuel	23,019.17	1.55	n.a	16.55	4.18	n.a
Solid fuel		321.09				
Oil and natural gas		94.63				
2. Industrial processes	21,401.02	226.46				

Sources: ALGAS

case study assumes that the generation output from the CCGT unit will replace that of a planned coal-fired generation unit. Three carbon prices are applied (See Chapter 4 for details).

The results from the COGEN model run are provided in Figure 43. This figure shows the importance of carbon credit revenue to improve project financial performance. Without carbon credit revenue, the IRR is estimated at 3.4 percent (before tax), and 2.7 percent (after tax), while the low carbon credit price case can raise IRR to 10.1 percent and 9.5 percent respectively.

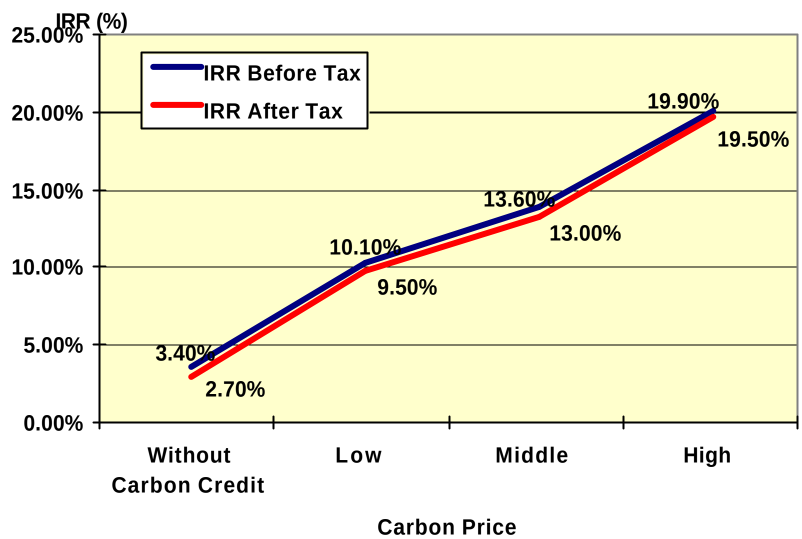
However, considering the discount rate at 12 percent in 1999, this project would not be commercial-

Table 19 Basic assumptions for CCGT generation unit replacement project

Installed Capacity	150,000*2(kW)	Fuel Price	2$/GJ	Electricity Price	0.03$/kWh
Capacity Factor	75%	Fuel Price Escalation	1.5%	Monitoring cost	30,000$/year
Plant Efficiency	45%	Capital Investment	700$/kW	O&M Cost	0.005$/kWh

Note: Cost assumptions are based on PLN Statistics 1999. Monitoring cost is estimated by APERC.

Figure 43 IRR for CCGT unit replacement project (Indonesia)

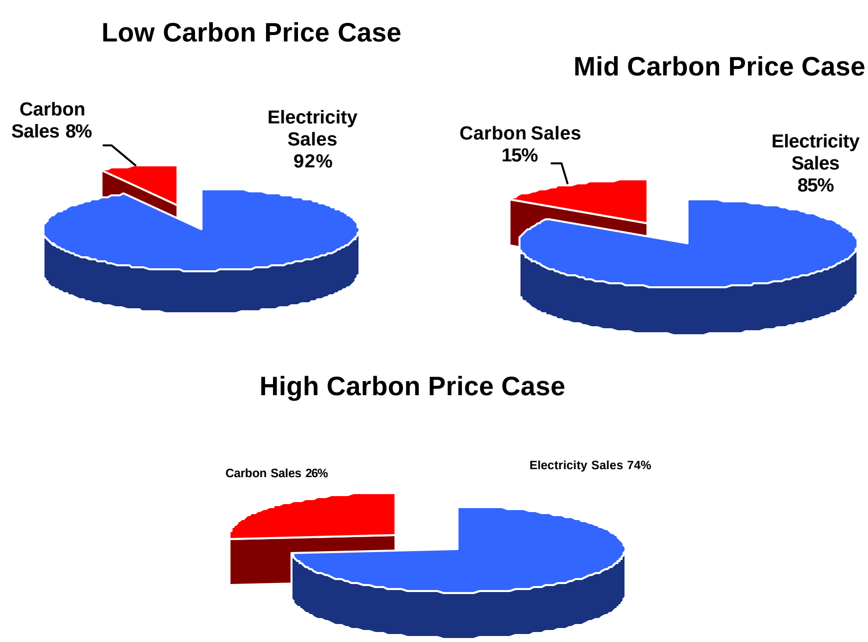


Note: Average electricity production per year is estimated at 1,931,580MWh. Total carbon emissions avoided over the project period are estimated at 5,134,605 ton-C.

ly practicable unless the carbon price is high. The poor financial performance is largely due to the low electricity selling price of 0.03$/kWh.

This is relatively unrealistic, as Indonesia has tended to enter into Power Purchasing Agreements with IPPs at more attractive terms then suggested here. With the recent financial crisis, there are increased risks in investing in Indonesia. These include exchange rate instability, high discount rates (See Chapter 4), and market risks such as future demand uncertainty.

Figure 44 Share of carbon and electricity sales to gross revenue (Indonesia)



THAILAND

The Thai government signed the United Nations Framework Convention on Climate Change on 12 June 1992, and ratified it on 28 December 1994. Thailand has recognized the importance of potential problems resulting from climate change and addressed the issue in a proactive manner. Climate change policy has been an integral part of the National Economic and Social Development Plan. On September 1993, the Prime Minister appointed the National Committee on Global Climate Change convention to coordinate the economy's climate change researches into the national environmental policy. Climate change policy principles are summarized in Table 20.

Thailand has supported UNFCCC efforts to stabilize GHG emissions, but recognises at the same time economic development needs, and has sought to develop energy policy objectives that encompass both ideals. Cooperation with UNFCCC initiatives has included AIJ and other voluntary initiatives. An example of Thailand's readiness to cooperate with the international community can be seen in its liberal policy toward technology transfer. The power tariff rate is lower for "clean" technologies than for "traditional" thermally generated power. The objective is to promote cleaner production [MOSTE, 2000a].

The Thai climate change planning process has relied on results of the ALGAS and US studies. In addition to national targets and objectives agreed initially by experts, CDM planning has received close oversight by Thailand's economic and social development planning agency (the National Economic and Social Development Board), in order to ensure the national action plan is compatible the CDM planning process followed by the national economic and social development plans. A GHG inventory for Thailand was first undertaken by the Thailand Environment Institute (TEI), and Thailand Development Research Institute (TDRI) in 1990. The subsequent inventory was conducted in 1994 by local researchers (Table 21). The Revised 1996 IPCC guidelines and some local emission factors were used to substitute some of the estimations in the 1994 inventory.

From the inventory, the three most important greenhouse gases are CO_2, CH_4, and N_2O, accounting for 71, 23, and 6 percent of total GHG emissions respectively.[21] The net emissions of CO_2 were about 201 million ton, with gross emissions of 241 million ton, and removal of 40 million ton. The major sources of CO_2 emission are from energy sector (52 percent), followed by land use change and forestry activities (42 percent), and industrial processes (6.6 percent). The CH_4 emissions came mainly from the agriculture sector (91 percent) and N_2O emissions were from fertilizer activities (95 percent).

Table 20 Thailand climate change policy principles

1 Equity principle	As a Non-Annex I country, Thailand has no reduction target obligations under the UNFCC. Annex I countries must take the lead in GHG reductions
2 Precautionary Principle	Thailand should participate and cooperate with other parties in taking precautionary measures against the potential adverse impacts of climate change, based on differentiated responsibilities and respective capabilities. Actions taken should be feasible, fair, and flexible, and achievable within a specific timeframe.
3 Principle of fairness, least risk, and impact	Local research capacity should be considered, with sufficient support provided for voluntary action and public participation. This is to ensure fairness and least impact on current development efforts.
4 Subsidiary principle	Countries having major sources of emissions are in the Western hemisphere, already identified in the UNFCCC as Annex I Parties. These countries must take the lead in the reduction of emissions.

Source: National Climate Change Action Plan for Thailand. Ministry of Science, Technology and Environment. Thailand Environment Institute.

Table 21 National greenhouse gas inventory for Thailand in 1994 (Gg)

Greenhouse gas source and sink categories	CO_2 Emission	CO_2 Removal	CH_4	N_2O	NO_X	CO	NMVOC
Total Emissions & Removals	241,030	-39,101.00	3,171	55.86	286.65	555.11	2,513.00
1. All Energy (Fuel Combustion & Fugitive)	125,482	0	196.55	0.83	271.85	33.9	0.72
A. Fuel Combustion	125,482	0	2.85	0.83	271.85	33.9	0.72
Energy & transformation industry	45,529		2.07	0.1	155.3	14.7	0
Industry, mining and construction	30,824		0.61	0.58	113.9	17.1	0
Transport	39,920		0.09	0	0.26	1.3	0.7
Commercial	890		0.02	0.08	0.87	0.2	0
Residential	3,469		0.06	0.06	1.37	0.5	0
Agriculture	4,849		0	0.01	0.15	0.1	0.02
B. Fugitive Emission			193.7				
Solid fuels			16.02				
Oil and natural gas			177.68				
2. Industrial Processes	15,970.40		0.31	0	0	0	2,512
3. Agriculture	0	0	2,879	54.62	0	0	0
A. Enteric Fermentation	0		629.53				
B. Manure Management	-		139.64	19.19			
C. Rice Cultivation	-		2,110.53				
D. Agricultural Soils	-		-	35.43			
E. Prescribed Burning of Savannas	-		-				
F. Field Burning of Agric Residues							
G. Others	-						
4. Land Use Change & Forestry	99,577	-39,101.60	59.57	0.41	14.8	521.21	0
A. Changes in Forest and Woody	40,180	-39,101.60					
Biomass Stocks	-						
B. Forest and Grassland Conversion	59,396		59.57	0.41	14.8	521.21	
C. Abandonment of Managed lands	-						
D. Others	-						
5. Waste	0	0	35.22	0	0	0	0
A. Solid Waste Disposal on land			19.57				
B. Wastewater Treatment			15.65				

Source: Center for Applied Economic Research, Report to MOSTE, October 2000

Note :
1. CO_2 emissions from traditional biomass burning are not included in subtotals and the national total.
2. CO_2 equivalents are based on Global Warming Potentials (GWPs) of 21 for CH_4 and 310 for N_2O, NO_X, and CO are not included since GWPs have not been developed for these gases.
3. Bunker fuel emissions are not included in the national total.

Since the 1990 GHG inventory, CO2 emissions from forestry and land use changes have declined, and emissions from energy activities haves increased. Several factors have contributed to the slowdown in emissions from forestry and land use changes. These include the imposition of a logging ban since 1989 and increased reforestation and commercial plantation activities. Increases in reforestation and plantation activities have raised the amount of carbon removed from the atmosphere. Energy combustion and fugitive emissions have become the largest source of CO_2.[22] The estimated quantities of CO_2 emitted from energy activities by sub-sectors are summarized in Table 22.

Table 22 Thailand - CO_2 emissions from fuel combustion in energy sector

Economic Sector	1994	1995	1996	1997	1998
			Gigagrams		
Transport	39,973	46,958	51,403	54,831	47,980
Power generation*	49,712	54,433	61,902	67,581	62,429
Industrial	26,415	31,007	34,945	31,664	27,539
Residential& Commercial	3,236	3,571	4,036	4,008	3,660
Others	5,993	5,781	6,611	5,875	6,690
Total CO_2 Emissions from Fuel Combustion	125,329	141,750	158,897	163,959	148,298

Source: Thailand Energy Situation (1998). DEDP, MOSTE
* Excluding hydropower

In 1998, total CO_2 emissions from energy conversion were estimated to be 148,298 thousand tonnes [DEDP, 1998]. The power supply sector, mainly power plants, emitted the largest share of CO_2 (62,429 thousand tonnes or 42.1 percent), followed by the transport sector (47,980 thousand tonnes, or 32.6 percent), and the industrial sector (27,539 thousand tonnes or 18.6 percent). From 1994 to 1997, the emissions rate increased rapidly corresponding to the rapid increase in final energy consumption over this period, (the average annual growth rate was 10% before the 1997 financial crisis). Real GDP grew by 8 percent per year and real economic output expanded by 10.5 percent annually. Even the 1997 financial crisis did not significantly change the energy consumption trend, but may have affected energy consumption patterns per capita. Future emission rates will depend on how rapidly the economy recovers and how successful industry is in improving energy efficiency levels.

Several studies have projected GHG emission trends over the long term. All the projections indicate increases in the carbon intensity of energy utilization as electricity use expands and more coal is used in electricity generation. The power sector will be the largest CO_2 emitter and its emissions will account more than half of total CO_2 emissions by 2020. A recent study by SIIT forecast that energy sector CO_2 emissions would reach 475 Tg by 2020 [MOSTE, 2000b]. This estimated figure is three times lower than estimations in the ALGAS report.

A report published by the National Environmental Policy Organisation (NEPO) has forecast the effects of measures to abate CO_2 emissions up to the year 2025. The Energy Conservation Plan Scenario (ECP) includes the impact of climate change policy actions and suggests substantial CO_2 reductions from the Business as Usual Scenario (see Table 23) [ERI, 1999].

ENVIRONMENTAL LAWS AND ACTIVITIES

Thailand faces both rural and urban environmental problems. The crucial problem is deforestation and resulting loss of biological diversity, soil erosion, flooding, and water shortages. In urban areas, air and water pollution concerns arise from the combustion of fuels and waste discharges from industrial and domestic sources. A recent study by the Pollution Control Department has stated that CO, lead, and particulate matter emissions exceed the national ambient air quality standards. Other pollutants, such as SO_2, NO_X and ozone have become a serious concern because of increased use of fuels from the growing population, urbanization, and industrialization. Thailand has recognised the environment as a very important issue and has included preventive and abatement measures in the national economic and social development plan including the climate change issue.

Table 23 Projected CO_2 emission levels by sector in 2025 in Thailand

CO_2 Emissions (kilo tonne)	Industrial[23]	Residential[24]	Commercial[25]	Transportation[26]
Year 2025 BAU	201,312		1,843	200,488
Year 2025 CONS	185,087	No environmental effects indicated in the study	1,523	158,524
Conservation effect (kton or Gg)	16,225		320	1,964
Effect of conservation in each sector	8%		17.4%	1%

Source: Summary Report of Thailand Energy Strategy and Policy. NEPO. November 1999
Note: 1. Least cost approach is used in long-term energy supply and environment analysis
2. BAU = Business As Usual. CONS = Conservation measures

Environmental and energy conservation laws and regulations have been established and periodically revised to reflect environmental needs. The Energy Conservation Act and the Thai National Environment Protection Law of 1995 stipulates energy conservation measures, while providing incentives for an energy conservation program, such as tax incentives, import duty exemptions (Energy Conservation Act of 1992). The energy conservation promotion fund makes subsidies available to projects that yield a rate of return below 9 percent.

Analysis of GHG emissions by sector shows that the transport and power generation sectors are the major contributors of emissions, and these sectors seem to have larger potential for technology transfer than other sectors. The electricity generation sector appears to be important as consumption has grown and will continue to grow faster than in other sectors. Fossil fuels are likely to remain a major source of energy, even in the long term, strategies such as promotion of clean fuel and new and renewable energy usages and efficiency improvement and conservation programs, will be essential. Standards are imposed on a polluter pays principal. Strict regulation has been imposed on the transportation, energy and industrial sectors.

The control of CO_2 and other emissions (SO_2, NO_X, and PM-10) from stationary sources can be achieved through the use of clean fuel and improved energy efficiency in plant operation. Because of environmental problems at the Laem Chabang, Map-Tha-Put and Mae Moh power plants in recent years, MOI and MOSTE authorities have required a higher degree of environmental control and protection. The OEPP project approval process has become stricter in terms of control, protection and abatement measures. Thailand is critically evaluating the use of fiscal mechanisms, i.e., environmental taxes through the application of “polluter pays principle” and “user pays principle” in the management of natural resources and the environment.

The operation of any plants, which has impact to environment, is subject to implement pollution abatement and preventive measures according to requirements in EIA reports.[27] If any plants fails to comply with regulation limits or measures, it will be enforced to change the process or fuel use in production. Environmental authorities (OEPP, MOI, or PCD) regularly monitor the environmental reports or Continuous Environmental Monitoring (CEM) report from heavy industrial plants.[28] In addition, if local communities have complaints, an investigation will be undertaken, and if the issue cannot be resolved, the MOI has the power to halt plant operation until the problem is solved.

Table 24 Emission standards for new power plants in Thailand

Pollutants	Emission standard			Methods
	Coal	Oil	Gas	
Sulphur dioxide, or SO2 (ppm)				US EPA Method 6,8 or other methods approved by Pollution Control Department
Power Plant Size				
500 MW	320	320	20	
300-500 MW	450	450	20	
<300 MW	640	640	20	
Oxide of Nitrogen or NOX as NO2 (ppm)	350	180	120	US. EPA Method 7 or other US. EPA Method 7 or other
Particulate (mg/m3)	120	120	60	US. EPA Method 5 or other methods approved by PCD

Source: http://www.pcd.go.th, Notification of the Ministry of Science, Technology, and Environment published in the Royal Government Gazette, Vol.113 Part 9 Page 220, dated January 30, 1996.

Notes: 1. Emission Standard for existing power plants, mixed fuel power plants, municipal waste incinerator, mining and quarry plants, industrial plants, Mae Moh power plants, crematory, and steel industry can be found from Pollution Control Department website.

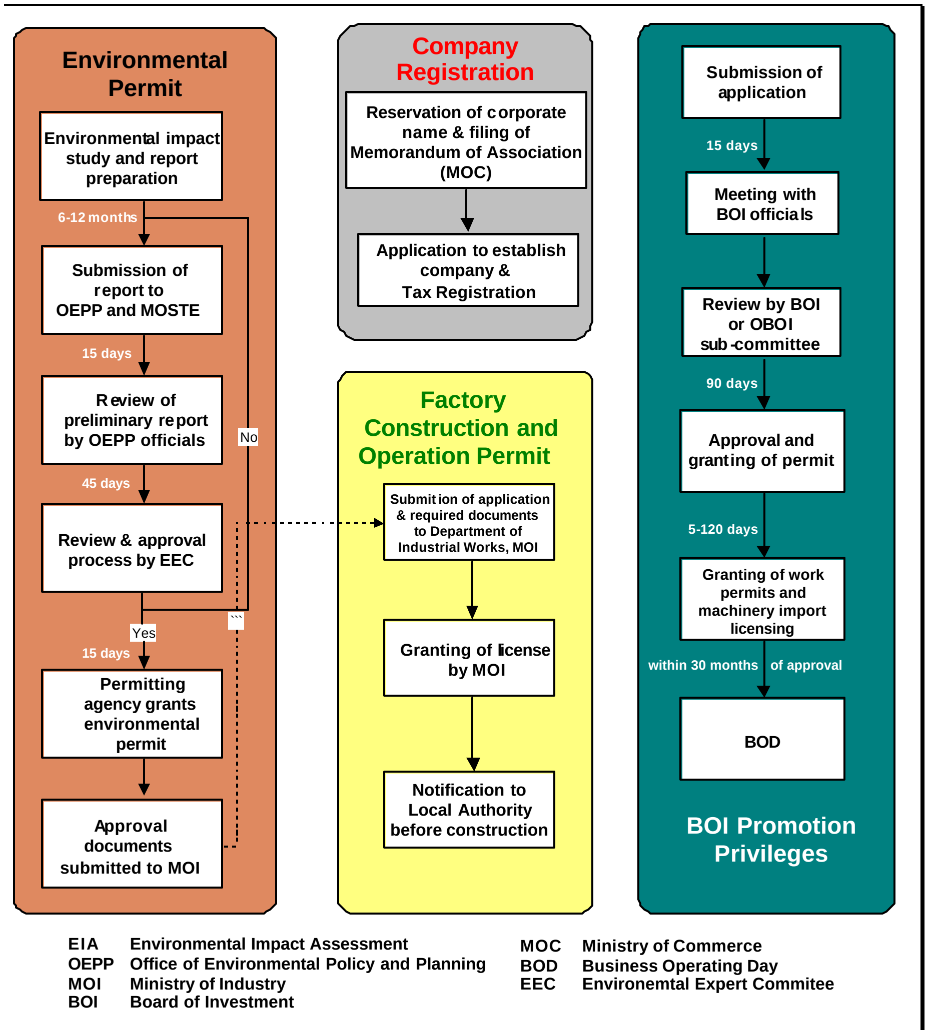
2. Reference Condition is 25 degree Celsius at 1atm or 760 mmHg, Excess Air at 50% or Excess O2 at 7% and dry basis.

RELEVANT LAWS AND PROJECT APPROVAL PROCESSES

Thailand is actively pursuing reform of its tax system, and taxes on industrial imports have already been sharply reduced. Over the past five years, the government has consistently moved to reduce import tariffs on machinery and taken measures to encourage investment, including tariff cuts - especially on raw materials and capital goods. As part of the Board of Investment (BOI) promotion program, the promoted companies are eligible for exemptions from or reductions in import duties on raw and essential materials as well as machinery.

The BOI promotes foreign investment and offers two benefit options: tax-based incentives, and non-tax privileges. Tax incentives include tax holidays or tariff exemptions, and non-tax privileges include guarantees and services. The non-tax privileges are available to all BOI-promoted projects, regardless of

Figure 45 Project approval process in Thailand



Source: BOI, MOC, MOSTE, OEPP

location, industry, and services. Tax-based incentives, on the other hand, depend on several factors. All projects will receive certain benefits. However, additional incentives are available for locating in Special Investment Promotion Zones, producing for export, or engaging in industries identified as priority activities. The Board has identified projects in the following five areas to be priority activities:

1. Basic transportation systems
2. Public utilities
3. Environmental protection and/or restoration
4. Direct involvement in technological development
5. Basic industries

The enabling activities of BOI to the implementation of mentioned projects include following privileges, a) corporate income tax exemption for eight years, and further reductions of 50 percent for additional years; b) income tax deduction for water, electricity and transport cost for 10 years from the date of first sales; c) deduction of the costs of installation or construction of the project's infrastructure facilities from net profits; d) exemption of dividends to shareholders from personal income tax; e) 50 percent import duty reduction on machinery which is not included in the tariff reduction of the Ministry of Finance and which is subject to import duty greater than or equal to 10 percent for projects located in Zone 1 or Zone 2; f) and import duty exemption on machinery for projects located in Zone 3.

An Independent Power Producer (IPP) program has received great interest from foreign and local companies in building, owning, and operating large-scale power plants. IPP projects are wholly private undertakings. Key terms set by the government are that:

- IPP power prices should not exceed EGAT's avoided cost;
- The contract period for the power purchase agreement must be between 20 and 25 years;
- The capacity of each project commissioned between 1996 and 2002 must not exceed 1400 MW, but may be expanded during the years 2003-2006;
- Investors must have proven technological capability matching the required performance specifications;
- Fuel choices must be clear, acceptable to the public, have a stable pricing structure and secure supply, and support the government's policy on fuel diversification for the economy.
- Priorities for project siting will be given in the following order; central region, west coast, east coast, other regions and neighbouring economies.

A POTENTIAL CDM PROJECT

This case study is biomass based generation unit project utilising rice husk as fuel. The basic information of biomass generation unit project is provided in the following Table 5. This case study makes assumption that same generation output from coal-fired generation unit is replaced by biomass generation. Three carbon prices utilised in Chapter 4 are applied here too.

PROJECT INFORMATION

The basic information regarding a biomass generation unit project is provided in Table 25. This case study assumes that the biomass generation unit will replace a coal-fired generation unit.

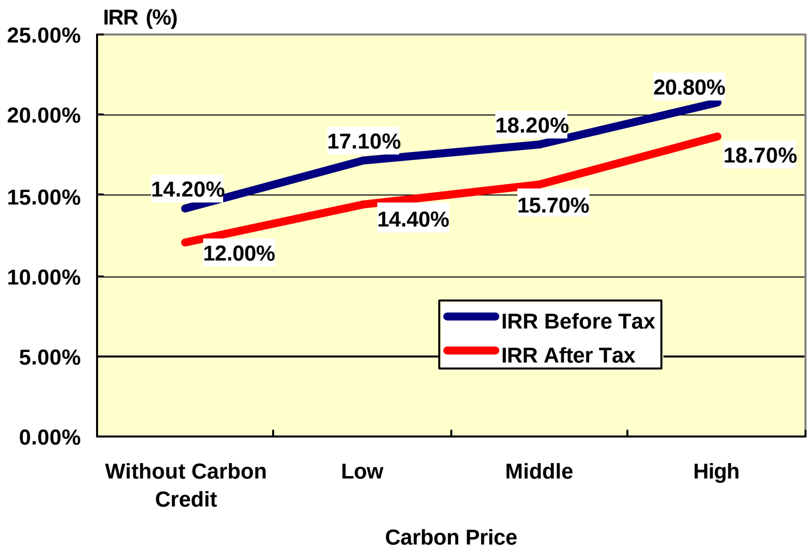
Table 25 Project specifications for feasibility study

Installed Capacity	10,000(kW)	Fuel Price	0.39$/GJ	Electricity Price	0.034$/kWh
Capacity Factor	85%	Fuel Price Escalation	0.5%	Monitoring Cost	30,000$/year
Plant Efficiency	35%	Capital Investment	1,100$/kW	O&M Cost	0.01$/kWh

Note: Cost assumptions are based on data from EGAT. Monitoring cost is estimated by APERC.

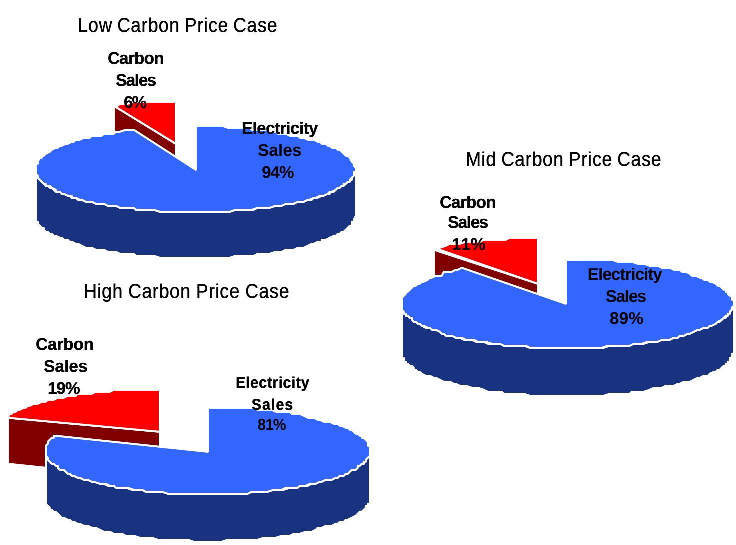
Figure 46 shows the results from the COGEN model run, and demonstrate an overall favourable financial project feasibility. This is largely due to the high capacity factor and low fuel price.

Figure 46 IRR for biomass unit replacement project (Thailand)



Note: Average electricity production per year is estimated at 74,460MWh. Total carbon emissions avoided over the project period are estimated at 170,519 ton-C

Figure 47 Share of carbon and electricity sales to gross revenue (Thailand)



Since Thailand is an agriculturally based economy, large amounts of biomass residues are produced. NEPO has established a Small Power Producers (SPP) programme to allow small biomass power generators in rural area to sell excess generation back to the grid. These incentive schemes would facilitate foreign investment in small-scale power generation project in rural area.

CHAPTER 8

MAKING CDM WORK

INTRODUCTION

Some of the more memorable images of the COP6 meeting were of angry demonstrators shouting and forecasting global doom, after the inability of ministers and diplomats representing many different domestic constituencies back in their own nations, to reach final agreement on making the Kyoto Protocol operational. One thing is becoming clear, final ratification of the Kyoto Protocol in the near future is no longer a foregone conclusion, especially with the change of administrations in the US, and the tough stance being taken by Europe on the key sticking points.

Making the Kyoto Protocol work will probably require a negotiated agreement that is much less stringent and ideologically pure than many hard-line environmentalists and some government negotiators will be happy with, and will certainly require a willingness to embrace innovative solutions. In a press release on 27th November 2000, Eileen Clausen, the Executive Director of the Pew Center on Climate Change, made the following observation. "In the long-term fight against global warming, we need every tool at our disposal. If we take carbon sequestration and market mechanisms out of the equation, or bog them down with such overly restrictive rules that nobody uses them, then we are limiting our ability to meet our environmental objectives. We are also undermining the political and business support that are needed - especially in the United States - to ratify the Protocol" [Claussen, 2000].

In her view, there was still language being negotiated that would make the Kyoto mechanisms totally inoperable or, at the very least, seriously limit their use: "if we define the mechanisms in ways that do not allow them to be used, or that allow them to be used in only limited circumstances, we are likely to increase the costs of complying with the treaty and make non-compliance the norm rather than the exception" [ibid].

It is the thesis of this report that the CDM rules as negotiated to date are already undesirably restrictive, and are in many respects unworkable, especially with respect to the concept of additionality, and also potentially with respect to baseline development.

ADDITIONALITY

As discussed in Chapter 3, environmental additionality is viewed as critical to the success and integrity of the CDM. To reinforce the additionality concept, proposals have been put forward for investment additionality, financial additionality, and technological additionality.

These ideas have been promoted to ensure that allowable CER credits can be quantified, that emissions reductions are real, and that Annex I countries don't use the CDM as a mechanism to avoid potentially expensive domestic greenhouse mitigation actions. In fact, leading up to COP6, European negotiators and environmental activists were accusing the US of using the promotion of flexibility mechanisms such as emissions trading and CDM as a smokescreen to avoid domestic action. Alden Meyer, Director of Government Relations with the Union of Concerned Scientists argued that: "the bottom line result for the US negotiating position is that virtually no pollution reduction measures would need to be undertaken in the United States."

Representatives of NGOs during the course of the COP6 meeting maintained the view that the CDM should not be an excuse for rich nations to unload old technology on poorer nations or use the mechanism to avoid domestic actions to mitigate greenhouse gases. A particular concern to some interest groups is the possibility of "free-riding." A free-riding CDM project is described as an investment that gets carbon credits for business-as-usual activities. The additionality concept is considered the key to discerning whether a project is legitimate or a free rider. Environmental groups believe that if free riders are not excluded, "the CDM will lead to net increases in emissions to the atmosphere as credits will be given to business-as-usual projects which do not drive emissions reductions," and "CDM will not drive technology change because investments will flow into business-as-usual investment [ECO, 2000]." In addition, it is believed that CER credits will be depressed and the share of proceeds for adaptation will be reduced if based on a percentage of the lower credit price.

The Pew Center argues for tough requirements for monitoring and verification and for making sure projects in developing countries result in clear environmental benefits. However, they are not convinced of the need for a slew of so-called "additionality tests," beyond environmental additionality, or other rigorous tests likely to inhibit the practical utility of the CDM. In their words "if the hurdles for using the CDM are sufficiently bureaucratic and cumbersome, they simply will not be used" [Claussen, 2000].

One could go further, and argue that the whole concept of "additionality" is flawed and liable to create considerable difficulties for investors willing to embrace the CDM concept, but fighting a rear guard action with hard-liners arguing that their project has not passed the additionality test.

The problem is that in the real world, and in particular in the fast developing Asia-Pacific - a region investors are willing to do business in because the risks are reasonable and the legal and financial institutions are sufficiently robust and mature compared with other developing regions in the world - is that proving that a project would not have happened otherwise will be a very difficult thing to do.

As shown in Chapter 8, the electricity sector in nearly all rapidly industrialising Asian economies is changing very fast, and almost any kind of power project one can imagine is not only possible, but likely. However, it is clear that many economies in the region are becoming much more carbon intensive with time, and in the next decade this trend will accelerate in some important economies unless incentives to moderate fuel choice for power generation are brought into existence.

In this situation, "business-as-usual" gas-fired combined cycle power plants replacing planned coal-fired plants would go a long way towards achieving real and substantive carbon emission reductions. However, such investments might not happen because the "rules" say they do not meet additionality tests. If such restrictive rules become entrenched, only a limited number of small-scale power supply projects are likely to qualify as CDM investments, probably using renewables such as wind and solar, and probably being very worthy projects, but not making any substantive contribution to overall global carbon emission reduction goals.

BASELINE DEVELOPMENT

Baseline development is another area where significant differences of opinion exist. While AIJ pilot project developers have tended to lean towards project specific baselines, it is becoming more widely accepted among experts that the transaction costs resulting from this approach would be too high for CDM projects. The most sensible approach suggested to-date is that of benchmark baselines, covering a whole sector or specific uniform elements of a sector [Lazarus *et al*, 1999; IEA, 2000].

Such an approach is ideally suited to the electricity generation sector, as technologies tend to be relatively uniform, and change at a slow enough pace to minimise the errors that result from aggregation of data for each major power generation technology type. Where relatively rapid change has occurred, in terms of the recent widespread adoption of natural gas combined cycle (replacing many single cycle gas turbine steam plants), and the increasing retrofitting of flue gas desulphurisation and particulate emission control devices, as well as low-NOx burners for coal-fired steam plants, there may be some discrepancies generated by aggregation of data.

However, the importance of this must be weighed against the cost of obtaining disaggregated data, and the impact of a baseline that may allow some degree of "free riding."

The recent IEA study *Emission Baselines: Estimating the Unknown* argues that "compared to highly aggregated multi-project baselines (for example, all plants operating in one economy), less aggregated multi-project baselines are likely to provide a better reflection of business-as-usual investments at one point in time" [IEA, 2000]. While undoubtedly true, this must be balanced against data availability and the cost of obtaining relevant data if it is available. With deregulation and electricity sector privatisation leading to a growing number of IPPs engaged in power generation development in the Asia Pacific region, obtaining data on individual power stations is likely to be difficult and/or expensive.

Aggregate data for each APEC economy is gathered however, and this is made publicly available through the APEC Energy Database managed by EDMC in Japan.[29] The same data can be obtained from the IEA, or from energy policy departments in individual economies.

The above IEA study provides a "wish list" of plant-specific data that would be desirable in order to construct multi-project baselines. The list includes: commissioning date; type of technology; fuel type; generating capacity; load factor; conversion efficiency and emission factor. Although such information would be very valuable in constructing targeted multi-project baselines, it is the thesis of this report that such an approach to baseline setting for the electricity sector may be difficult to achieve, and hence not the most pragmatic approach. There are a number of reasons for arguing against such an approach. Firstly, such plant-specific data is generally unavailable or would be costly to obtain.

For example, although the fuel types and technologies being installed in planned and partly constructed plants are often available through national energy plans, load factor will not be well known in advance, and conversion efficiencies are subject to change over time, depending on how well the plant is maintained over its lifetime, fuel quality and other factors. The data that is collected nationally and made available through international databases is: primary energy balance, power generation fuel consumption, and net power generation by fuel type (often not disaggregated for thermal fuels).

Baselines will be constructed on the basis of historical and projected data. While major uncertainties will exist with respect to future projects - especially for fast changing economies - there are also data issues with respect to historical data. The IEA study mentioned above suggests using recent historical data and information on plants being planned or under construction to avoid mid to long-range forecasting uncertainties, and suggests that this approach offers a good proxy for "what would occur without CDM/JI projects" in the electricity sector. This approach is sensible, as data based on short-term projections is available and will be a relatively reliable guide to what will happen in the near-term.

Another important consideration when agonising over data availability for different plants or plant types, is that the way any individual plant is operated may actually have a substantial impact on its carbon intensity. For example, the data analysed in this study suggests that a well-maintained baseload oil-fired plant may have substantially lower carbon intensity than such a plant used only for peaking operation (and possibly poorly maintained). This observation is supported by other evidence [IEA, 2000] that peaking plants typically run at significantly lower efficiency levels and have correspondingly higher carbon intensities than baseload plants of the same fuel and technology type.

As argued in the IEA and other studies [IEA, 2000], baselines should be confined to the direct emissions from a power generating plant, and not take into account full life-cycle GHG emissions. This eliminates the accounting problems associated with imported fuels, and overcomes difficulties in establishing full life-cycle emissions.

Given the rapid rate of change in Asian power markets, baselines may have to be reviewed and updated at frequent (perhaps 5 year) intervals. The baseline for a specific CDM project should, however, remain constant for the economic (or perhaps actual) lifetime of the project. This compensates for the additionality criteria. A cleaner plant is replacing a less clean technology at the time of installation, therefore the real emission reductions are those avoided at the time of commissioning. Electricity generation plants tend to have long actual lifetimes, and refurbishment in developing economies desperately in need of additional baseload capacity, may be infrequent. This approach will maximise the credits obtained, and hence the economic attractiveness of the project. This and other studies demonstrate that CDM credits (at realistic carbon prices) do not greatly increase the economic attractiveness of a project, so a liberal approach to crediting will be needed if CDM projects are to occur to any significant extent.

BARRIERS

Although the APEC region has great potential as the focus of a substantial amount of CDM investment, it is possible to identify a number of barriers to the realisation of this potential. These have been alluded to throughout this report, and are collated here for convenience:

- Capital limitations and higher risk premiums on capital than in developed economies;
- Limited local R&D investment, and limited data on potential resources (particularly renewables) for CDM investment;
- A general weakness of institutional frameworks;
- A lack of supporting energy network infrastructure for some attractive CDM projects;
- Uncertainties related to profitability and risk arising largely from distrust of the stability of regulatory regimes, and likely shifts in energy policies;
- A lack of supporting environmental policies and incentives to encourage clean energy technology development;
- Overly restrictive CDM rules on additionality and baseline setting;■
- Potentially high transaction costs, especially for small-scale projects; and
- The limits to which carbon credits can make financially unattractive (but clean) investments attractive to investors.

CONCLUSIONS

CDM, for it to be of any real value in helping to mitigate greenhouse gas emissions, should not be considered as a narrowly targeted tool influencing an investment decision here and there, but as an opportunity to influence the greenhouse gas emissions trajectories of rapidly industrialising economies. Eileen Claussen, President of the Pew Center on Global Climate Change, argues that “rather than attempting to pressure developing countries into accepting binding emissions reduction targets in this decade, we should be working to influence the character of the investments made in these countries and to insure that these investments are climate-friendly” [Claussen, 2000].

This is the approach considered in this study. Over the next ten to fifteen years, fast developing APEC economies (with energy sector growth rates of 6-8 percent per annum) will duplicate their entire electricity supply infrastructures. This means twice as many power stations - as well as all supporting network infrastructure to bring power to individual consumers. If one considers just the fast growing southeast and northeast Asian economies (China, Singapore, Malaysia, Thailand, Indonesia, Philippines, Korea, Chinese Taipei), net power generation will grow from 1,842 TWh in 1998 to around 3,700 TWh in 2010. Assuming the planned fuel mix, carbon emissions will grow from 1,275 million tonnes of CO_2 in 1998 to over 2,550 million tonnes in 2010 (assuming a business as usual growth trend).

If this growth trend in carbon emissions is to be mitigated in any significant way, every tool available - including CDM - will need to be invoked. A strong driver will be the impacts (health and environmental impacts) of coal combustion in low efficiency boilers - a major problem in China. Development of electricity supply infrastructure will need to move decisively towards cleaner fossil fuel technologies and alternative resources such as renewables.

Endnotes

1 Those listed in Annex I of the UNFCCC, and comprised mainly of developed countries.

2 Article 3.1 of the Kyoto Protocol

3 Article 6.1.(d), 12.3.(b), 17 of the Kyoto Protocol

4 It is not Annex I Parties but Annex B parties that can participate in emissions trading, as specified in Article 17 of the Kyoto Protocol. ("The Parties included in Annex B may participate in emissions trading for the purposes of fulfilling their commitments under Article 3."). Annex B Parties are those listed in Annex B of the Kyoto Protocol, the list being almost identical to the list of Annex I Parties.

5 Unlike emissions trading, since CDM requires the assessment of GHG emission reductions by independent "Operational Entities," the certification process will generate transaction costs that may become a barrier to project implementation.

6 Gaming would involve attempts by investors to use rigidities in market rules to increase their returns on investment - in this case to inflate the number of carbon credits over might, with more tightly defined market rules, be reasonable.

7 Forests can only be considered as carbon sinks where they are newly established, and replacing less carbon intensive vegetation such as pasture and crops. Established indigenous forests are in equilibrium with respect to the carbon cycle - they absorb some carbon as tress grow and release carbon as litter on the forest floor decays. Plantation forests can only be considered carbon sinks where the carbon remains locked up in the wood products after harvesting.

8 Valuation of environmental assets is one of the most difficult areas in environmental economics, where a few pragmatic approaches are suggested through the use of non-market valuation methods. See Smith (2000).

9 The list is by no means exhaustive.

10 Marginal user cost is the present value of foregone opportunities resulting from greater current consumption of depletable and scarce resources at the expense of future consumption.

11 Discount rate is defined as the interest rate the central bank charges their member banks for loans, using government securities as collateral. In general, the discount rate is the lowest likely interest rate.

12 Joint venture can take form of (1) contractual joint venture, (2) equity joint venture and (3) wholly foreign owned joint venture. In the case of cross border M&A, the ownership of more than 10 percent of shares falls under the FDI category, while the ownership of less than 10 percent of share falls under FPI.

13 Ownership advantage is called "Firm Specific Advantage" also.

14 Available at http://eetd.lblgov/proform/

15 The high fuel price against a baseline coal-fired unit with 35 percent thermal efficiency is not shown as the result indicated a negative level of performance.

16 According to NEA/IEA estimates, fuel cost accounts for 70 percent of total project cost (see Figure 23).

17 In this report the term "fuels" is used to describe all primary energy sources used to generate electricity, even when those energy sources (hydro, wind, solar) are not fuels in the strict sense of the word.

18 Since solar PV panels can be placed at the “point of use” of electricity, they compete against the retail price of electricity, not the wholesale (generation) price.

19 Available at http://eetd.lblgov/proform/

20 Through the 1994 Act No.6 - later replaced by the 1999 government regulation No 41.

21 Comparatively in CO_2 equivalent units (CEU): CO_2 emitted 202,458 CEU, N2O emitted 17,317 CEU, and CH_4 66,598 CEU. Total CO_2 equivalent emissions in Thailand. Thailand's initial national communication. October 2000.

22 Including extraction, processing, transportation, storage and distribution

23 Electricity Savings: alternative processes, efficient process services in food processing, textile, and cement. High efficiency motor, variable speed motor control, non-electrical energy savings: boiler efficiencies in coal fired and biomass-fired

24 Electricity saving in DSM (Rice cookers and air-conditioning)

25 Electricity saving in DSM (Air conditioning and specific electrical use)

26 Potential energy saving measures in transport fuel: energy reduction in air transport, better train design for rail transport, energy efficiency of cars/trucks, transportation demand intensity, energy efficiency gain from freight transport mode

27 Environmental Impact Assessment report approval is required by law to grant permit to operate plant/project in Thailand

28 On line emission monitoring system, which directly link to Pollution Control Department

29 APEC Energy database can be accessed on the Internet at: http://www.ieej.or.jp/apec/.

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APPENDIX I

HISTORY OF CLIMATE CHANGE NEGOTIATIONS

With the development of industrialisation, and the changes in land use and agricultural practices after the industrial revolution, consumption of fossil fuels increased drastically. Fossil fuel burning, industrial processing and intensive agriculture over the last hundred years or so have resulted in very large-scale emissions of gases with global warming potential.[1]

Greenhouse gases trap some of the outgoing solar heat radiation within the atmosphere, in a similar way in which the glass panels of a greenhouse trap the sun's warmth. This is a natural process - water vapour in the atmosphere is the most important greenhouse gas - but the concern is that additional emissions of anthropogenic greenhouse gases could lead to excessive global warming, possibly leading to large-scale and irreversible changes in climate.[2]

It was only in the latter half of the 1980s that a “global warming problem” was identified and started receiving international attention.

BEGINNING OF INTERNATIONAL NEGOTIATIONS

International negotiations on environmental problems generally follow the following steps:

1. Scientific recognition and consensus building.
2. Discussion of the problem in an international arena.
3. Cooperation between scientists and policy makers.
4. Adoption of an international framework convention.
5. Ratification of a Convention Protocol.

In the case of global warming, although the greenhouse effect has been understood since the 1820s, a scientific conference held in Villach, Austria in 1985 was the first occasion when a broad scientific consensus was acknowledged. This meeting concluded that: “although quantitative uncertainty in modelling results persists, it is highly probable that increasing concentrations of the greenhouse gases will produce significant climatic change.” The 1987 Bellagio Conference consolidated the scientific consensus on global warming and the first joint communication of scientists and policy makers was issued.

FROM TORONTO CONFERENCE TO UNCED

The Toronto Conference in June 1988, jointly attended by scientists and policy makers, made important progress on the global warming issue. This conference proposed the following three points:

1. A 20 percent reduction in Global CO_2 emissions from 1988 levels by the year 2005.
2. Development of “a comprehensive global convention as a framework for protocols on the protection of the atmosphere.”
3. Establishment of a “World Atmosphere Fund” to be financed in part by a levy on fossil fuel

consumption in industrialised countries."

Even though this was not an official negotiation meeting, it was far more influential than other meetings in its call for a 20 percent reduction in CO_2 emissions from 1988 levels by the year 2005 because of the Canadian government sponsorship and the participation of high status government officials. This was the first of a series of international discussions on climate change involving both scientists and policy makers (see Table 26).

After the Toronto conference, political concerns about the risks of rapid climate change were raised and scientists voiced their alarm and called for early action to reduce the risks. Shortly before the Toronto conference, governments requested the WMO and UNEP to create a body called the Intergovernmental Panel on Climate Change (IPCC). The IPCC was asked to conduct a scientific and technical assessment of atmospheric changes and their impact.

ESTABLISHMENT OF THE FCCC

On 11th December 1990, the 45th session of the UN General Assembly adopted a resolution to establish the United Nations Framework Convention on Climate Change. At the United Nations Conference on Environment and Development held at Rio de Janeiro in June 1992 (the Earth Summit), the framework convention was presented for signature. It came into effect in March 1994.

The main objective of the convention is to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Under the Convention, the Parties to it have committed themselves to reductions of GHG emissions to 1990 levels. However, the first national communications from Annex I Parties have demonstrated the difficulty most have had in meeting this target, hence the strong call for establishment of a legally binding protocol to strengthen the commitment of Annex I Parties.

THE PATH TOWARDS THE KYOTO PROTOCOL (COP1/COP2)

The first Conference of the Parties to the UNFCCC (COP1) met in Berlin from 28 March to 7 April 1995. The focus of attention was on the review of the adequacy of commitments and the negotiation of a mandate for a protocol. The meeting recognised that the GHG mitigation obligation of Annex I countries was inadequate, and a decision called the "Berlin Mandate" was agreed for the purpose of establishing a protocol by COP3 in 1997. This protocol would require Annex I Parties[3] to elaborate policies and measures and set quantified limitations and reduction objectives within specified time-frames (such as 2005, 2010 and 2020 for anthropogenic emission reductions by sources and removals by sinks not controlled by the Montreal Protocol).

The Second Conference of the Parties (COP2) met in Geneva from 8-19 July 1996. COP2 concluded with the "Geneva Declaration," which refers to the IPCC conclusions in the Second Assessment Report and called for the need for legally binding objectives and significant reductions in GHG emissions.

COP3

COP3 was held from 1-11 December 1997 in Kyoto and Parties to the UNFCCC adopted the Kyoto Protocol on 11 December. The main achievement of the Protocol was to set emission reduction targets[4] for Annex I Parties. Annex I Parties agreed to commitments to reduce overall emissions of six GHG gases by at least 5 percent below 1990 levels during the first commitment period (2008-2012). Emission reduction targets are differentiated among Parties (Figure 47), reflecting the result from negotiation among Parties.

The Kyoto Protocol, as a whole, is composed of three parts: (1) Commitment on emissions, (2) Rules

Table 26 History of international climate change negotiations

1986	October	Villach Meeting (Austria)	First international meeting on global warming – considers scientific perspectives
1987	November	Bellagio Meeting (Italy)	First international meeting on global warming involving policy makers.
1988	June	Toronto Conference on the Changing Atmosphere	Scientists and policy makers meet for first time to discuss climate change.
	November	Establishment of Intergovernmental Panel on Climate Change (IPCC)	
1991	February	First Meeting of United Nations Framework Convention on Climate Change (UNFCCC)	First IPCC Assessment Report calls for urgent ratification of convention on global warming.
1992	June	United Nations Conference on Environment and Development (UNCED)	Parties begin signing the UNFCCC.
1994	March	UNFCCC entry into force.	
1995	March	First Conference of the Parties (COP1) at Berlin	“Berlin Mandate” adopted. It promulgates new protocols to be introduced by COP3.
	December	IPCC 11th Meeting	IPCC releases Second Assessment Report.
1996	July	Second Conference of the Parties (COP2) at Geneva	COP concludes by endorsing the “Geneva Declaration” - including calls for legally binding targets & big reduction in GHG emissions.
1997	December	Third Conference of the Parties (COP3) at Kyoto	Delegates adopt “Kyoto Protocol” promulgating GHG emissions reduction targets and other measures.
1998		Fourth Conference of the Parties (COP4) at Buenos Aires	Delegates adopt “Buenos Aires Plan of Action” that includes preparation schedule for entry into force of the Kyoto Protocol.
1999		Fifth Conference of the Parties (COP5) at Bonn	32 decisions and conclusions adopted for review of the implementation of commitments.
2000	November	IPCC Third Assessment Report	
2000	November	Sixth Conference of the Parties (COP6) at The Hague	

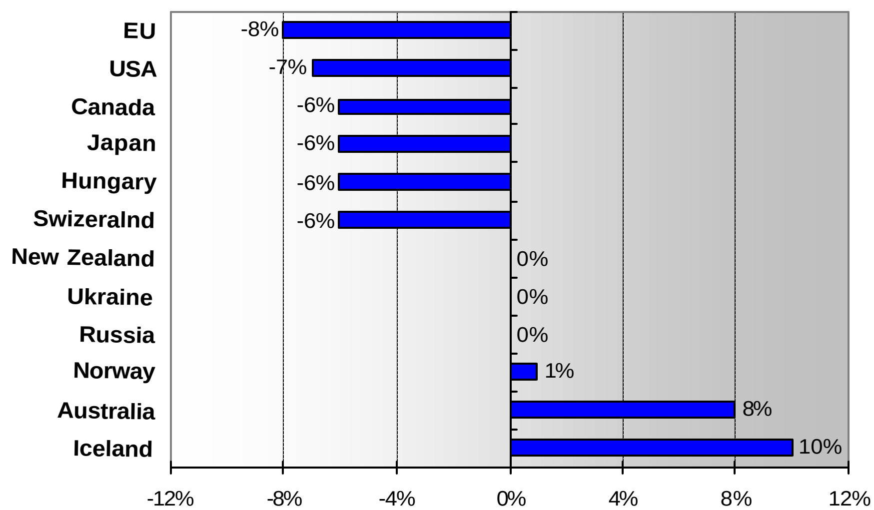
governing compliance, (3) Procedural rules.

The Protocol provides differentiated targets, a time period for compliance, as well as measures to meet targets, such as “Banking,” “Bubbles” and the “Kyoto Mechanisms” as explained in Table 27.

Entry into force, review and amendments of the Protocol is decided as shown in the following table. The MOP will take responsibility for implementation of the Protocol after its entry into force.

The Kyoto Protocol provides the framework for strengthening commitments. Establishment of rules, modalities and guidelines were deferred to later COP meetings.

Figure 48 Emissions reduction targets for some selected Annex I Parties



Notes: 1990 base year

COP4

Table 27 Main Kyoto Protocol decisions on emissions commitments

Topic		
Greenhouse gases	Annex A	Carbon dioxide (CO_2), Methane (CH_4), Nitrous oxide (N_2O), Hydrofluorocarbons (HFC), Perfluorocarbons (PFC), Sulphur hexafluoride (SF6)
Base Year	Article 3	1990 (Annex I may use 1995 as base year for HFC, SFC, SF_6)
Commitment Period	Article 3	First commitment period is from 2008 to 2012.
Emissions Reduction Target	Article 3	Annex I Parties will reduce overall emissions of greenhouse gases by at least 5% below 1990 levels in the commitment period 2008 to 2012.
Banking	Article 3	If the emissions of a Party included in Annex I in a commitment period are less than the target, the difference will be added to the assigned amount for this Party in subsequent commitment periods.
Bubble	Article 4	Parties are allowed to act jointly in the mitigation of emissions (in a frame-work of regional economic integration).
Kyoto Mechanisms	Article 6	COP adopted the introduction of cost effective GHG reduction measures generally called Kyoto Mechanisms. Kyoto Mechanisms include Emissions Trading, Joint Implementation (JI) and the Clean Development Mechanism (CDM).

Table 28 Main Kyoto Protocol decisions on compliance

Demonstrable progress	Article 3	Each Annex I Party shall make demonstrable progress towards achieving commitments by 2005.
National system for estimation	Article 5	By the end of 2006, a national system for the estimation of GHG emissions and removals by sinks will be established.
Inventory	Article 7	Annual inventory shall incorporate necessary information for ensuring compliance (7.1). MOP1 will determine guidelines for submission.
National communication	Article 7	National communication shall incorporate necessary information to demonstrate compliance (7.3). Guidelines for submission will be determined at MOP1.
Expert review	Article 8	MOP1 will adopt and review guidelines for the review of implementation.
Non-compliance	Article 18	MOP1 will approve appropriate and effective procedures to determine cases of non-compliance with the provisions of the Kyoto Protocol.

The Kyoto Protocol agreed at COP3 was a landmark event, however it was not the end of the process. Negotiations were held to resolve the unfinished issues in the Protocol in the Fourth Conference of the Parties to the UNFCCC held from 2-13 November 1998 in Buenos Aires.

Table 29 Main Kyoto Protocol decisions on rules, modalities and guidelines

Review of the Kyoto Protocol	Article 9	MOP will review the Kyoto Protocol periodically. First review will take place at MOP2.
Amendments to the Protocol	Article 20	Amendments shall be adopted by consensus. If consensus fails, at least three-fourths majority voting is required.
Amendments to the Annex	Article 21	Amendments shall be adopted by consensus. If consensus fails, at least three-fourths majority vote is required.
Entry into force of the Protocol	Article 25	Entry into force requires ratification from not less than 55 Parties to the Convention incorporating 55 percent of total carbon dioxide emissions for 1990 of Annex I parties. The Protocol shall enter into force on the 90th day after the ratification of condition mentioned above.

Delegates adopted the Buenos Aires Plan of Action under which the Parties declared a determination to prepare for the future entry into force of the Kyoto Protocol. The Plan contains the Parties' resolution to demonstrate substantial progress on the following 6 points by COP6: (1) a financial mechanism; (2) the development and transfer of technology; (3) adaptation plans for small islands and compensation for oil producing countries; (4) activities implemented jointly; (5) the mechanisms of the Kyoto Protocol; and (6) preparations for COP/MOP 1.[5] Below are the details of each item of the Buenos Aires Plan of Action.

FINANCIAL MECANISMS

Article 11 of the UNFCCC provides funding for actions by developing countries. These actions include mitigation, adaptation and response measures, preparation of National Communications and capacity building. The Global Environmental Facility (GEF) was set up in 1991 to establish a mechanism for providing financial support to developing countries.

DEVELOPMENT AND TRANSFER OF TECHNOLOGIES

The UNFCCC also promulgates the transfer of technology in addition to financial mechanisms. Annex I parties have long argued that governments cannot transfer technology because they do not, in most cases, own the relevant patents. COP4 made some progress when Annex II Parties[6] were asked to "take all practicable steps to promote the transfer of technologies." Non-Annex I Parties are asked to submit their technology needs.

ADVERSE EFFECTS[7]

Adverse effects are categorised into:

(1) The effects of climate change such as droughts and floods, and weather extremes.

(2) The effects of the implementation of response measures and the commitments of the Kyoto Protocol.

Firstly, the effect of climate change is relevant to the "adaptation problem" for countries that are vulnerable to climate change. Secondly the effects of implementation concern "compensation" to fossil fuel exporting countries for losses of revenue from lower sales of fossil fuels.

On this issue, a work programme has been established, calling for a workshop at COP5 and decisions at COP6, the basic elements of analysis have been determined, and the IPCC is to report in its Third Assessment Report.

ACTIVITIES IMPLEMENTED JOINTLY (AIJ)

AIJ was set up at COP1 as a pilot phase to gather experience on Joint Implementation. Soon after COP1, over a hundred projects were implemented, but many were not in developing countries.[8] COP1 concluded that decisions on the pilot phase would be made no later than 2000. However, developing countries have called for an extension of the programme. Therefore, the COP has decided to continue the AIJ pilot phase.

THE KYOTO PROTOCOL MECHANISMS

Since the Kyoto Protocol only provides the framework for the mechanisms, the design of rules and guidelines are deferred to later COP sessions. COP4 decided on the work programme for the mechanisms with the target that "decisions on all the mechanisms under Articles 6, 12 and 17 [9] of the Kyoto Protocol would be finalised at its sixth session" with the priority given to the Clean Development Mechanism.

PREPARATIONS

COP will also serve as a Meeting of the Parties to the Kyoto Protocol (COP/MOP) after its entry into force. The first meeting after the Kyoto Protocol entry into force is called COP/MOP1. The preparations for this meeting have given priority to compliance issues.

COP5

The Fifth Conference of the Parties (COP5) to the UNFCCC was held in Bonn from 25 October to

5 November. Delegates adopted 32 draft decisions and conclusions concerning review of the implementation of commitments and other FCCC provisions and preparations for the COP/MOP1.

COP6

The Sixth Conference of the Parties (COP6) was held in The Hague from 13-24 of November 2000.

The key issues addressed in the meeting were: (1) sinks, (2) operational details of the Kyoto mechanisms, (3) compliance and (4) capacity building, technology transfer and adverse effects. During the second week of the meeting, Ministers and negotiators were grouped into four groups to reach agreement on these issues. One day before the meeting was over, the COP-6 President Jan Pronk provided "a President's Note," to facilitate negotiation progress on key issues. However, parties failed to reach final agreement on issues relating to supplementarity and definition of sinks. To allow for further discussion of the crunch issues, COP-6 Part II will be held during the course of 2001.

Endnotes

1 The important anthropogenic greenhouse gases being discussed within climate change negotiations are: CO2, CH_4, N_2O, HFC, PFC, SF_6.
2 The greenhouse effect is a natural geophysical process.
3 Annex I Parties: Countries listed in Annex I of the Convention. Includes some developed countries in the OECD and economies in transition.
4 Emission reduction target is officially called "Quantified Emission Limitation or Reduction Commitment."
5 MOP: Meeting of the Parties that takes place after the ratification of the Kyoto Protocol.
6 Annex II Parties are the OECD countries of Annex I.
7 Adverse effects are covered in Paragraphs 8 and 9 of the Convention and Articles 2.3 and 3.14 of the Kyoto Protocol.
8 According to the second synthesis report, out of the 95 projects, only 27 took place in developing countries.
9 Article 6 of the Protocol covers Joint Implementation, Article 12 of the Protocol covers the CDM and the 17 covers Emissions Trading.

APPENDIX II

ACTIVITIES IMPLEMENTED JOINTLY

INTRODUCTION

The Activities Implemented Jointly[1] (AIJ) concept was established at COP-1 in Berlin in 1995. It originated from Joint Implementation (JI), which had been introduced earlier as an international co-operation mechanism for all Parties to the Climate Change Convention to stabilize GHG emission levels. Under the non-compulsory AIJ rules, GHG reduction and sequestration projects can be carried out through partnerships between investors from Annex I countries and hosts from non-Annex I countries.[2] To test the viability of the scheme, and prior to final agreement on the introduction of the scheme, a pilot phase was introduced. During this phase, no credits may accrue to any Party for greenhouse gas emission reductions or removals.[3] The AIJ learning experience was intended to help both investors and host countries to design an international framework for both JI and the Clean Development Mechanism (CDM).[4]

The AIJ pilot phase began in 1995 and was supposed to end in 1999. However, final agreement has not yet been reached on full implementation of flexibility mechanisms, and a large number of projects have been mutually agreed but were not in progress by the end of 1999. At the COP 4 meeting, it was agreed to prolong the pilot phase study for an undetermined period.[5]

PORTFOLIO OF AIJ PROJECTS

Government approval is a legal prerequisite to AIJ project approval under the Berlin Mandate (Decision 5 CP1). All pilot projects must be backed by a mutual agreement,[6] approved and endorsed by host and investor economy governments. As of September 2000, there are 122 AIJ projects officially reported to the UNFCCC secretariat.[7,8] Thirty four countries are hosting projects while 11 countries have invested in projects (Table 30). The projects fall into the following categories: energy efficiency (49 percent), renewable energy (46 percent), forest preservation or reforestation (12 percent), fuel switching (7 percent), fugitive gas capture (4 percent), agriculture (2 percent), and emissions/sequestration from afforestation (2 percent). Over 75 percent of the projects are focused on either energy efficiency or renewable energy. So far, no activities involving industrial processes, solvents, or waste disposal have been reported.

Of the 108 projects that reported on the estimated amounts of GHG emissions reduced or sequestered (expressed in CO_2 equivalents) approximately two thirds of total impact is derived from 12 forest preservation or reforestation projects. Renewable and fugitive gas capture projects account for about 14 percent each, energy efficiency projects contribute less than 4 percent, and others contribute less than 2 percent each [UNFCCC, 1999]. Though significant numbers of energy efficiency and renewable energy projects have been proposed, these projects are small in terms of investment levels, as well as GHG mitigation compared to the forest preservation and fugitive gas capture projects.

Table 31 shows the distribution of AIJ activities by region and type. Energy efficiency and renewable energy projects are mainly focused on former Soviet Union and Eastern European countries. Forestry-related projects are dominantly focused on Latin America and Caribbean countries. Only energy efficiency and renewable projects have been reported in the Asia Pacific and African regions.

Table 30 AIJ investor and host countries

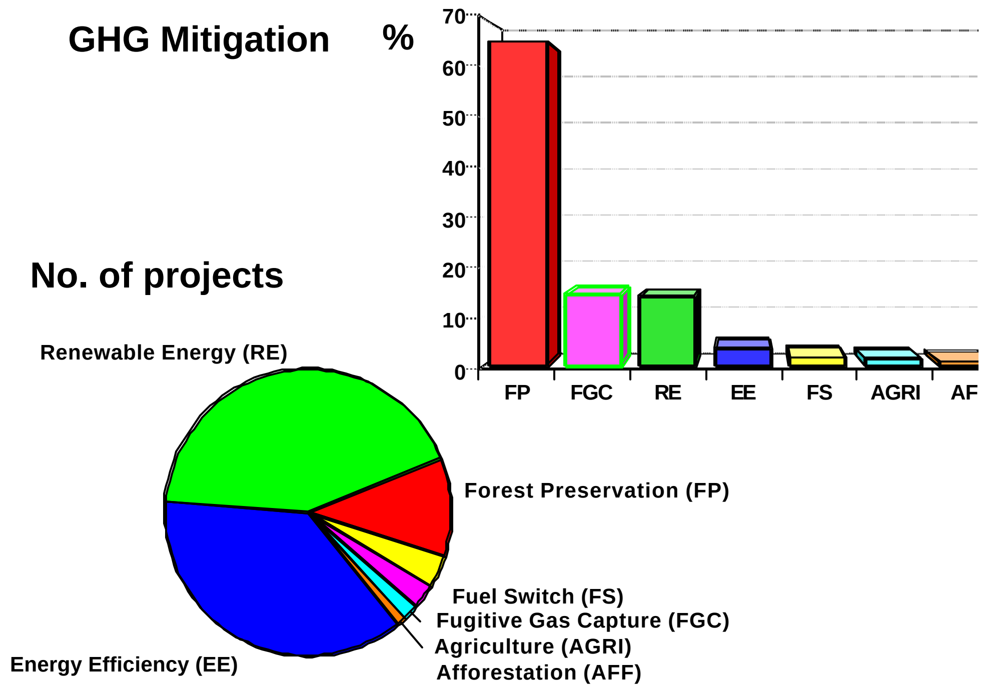
Investor Economy	Number of Projects
Sweden	51
United States	30
Netherlands	22
Norway	6
Australia	4
France, Germany, Japan	2
Belgium, Italy, Switzerland	1
Host Economy	
Latvia	24
Estonia	20
Costa Rica, Lithuania	9
Russia	8
Mexico	5
Bolivia, Honduras, Romania	4
Czech Republic, Hungary, Poland, Slovakia	3
Ecuador, Guatemala, Indonesia	2
Belize, Bhutan, Bulgaria, Burkina Faso, China, Croatia, Fiji, India, Mauritania, Mauritius, Morocco, Nicaragua, Panama, Solomon Islands, South Africa, Sri Lanka, Thailand	1

Source: UNFCCC Third Synthesis Report, 1999.

TARGET SECTORS FOR AIJ PROJECTS

In reviewing the investment portfolio of investing countries, it shows the pattern of AIJ investment to be region-specific. For Australia and Japan, the projects are taking place mainly in China and other Asian economies within the Asia-Pacific region. European projects are located within the former Soviet Union and Eastern European region and US projects are mostly in the Latin America and Caribbean region. The pattern is intra-Asian, intra-European, and intra-American cooperation - so called neighbourhood trading [Schwarze, 1999]. As a result, AIJ funding from each investing economy has remained entirely within its own region. Region specific projects are influenced by trade and development policy-related objectives and reflect the priorities of the host countries [Matsuo, 1999]. The uniform reporting formats in national programmes submitted by Parties consist of structure, approval process, procedures, and criteria for national acceptance of AIJ.[9] For example, the US is favouring forest-related projects in Costa Rica that correspond to Summit of the Americas and USIJI project criteria, and are mutually agreed by Costa Rica and reflected in its national programme as a priority.[10] In another example, Japan focuses on technological mitigation activities and places priority on sharing environmental technology and services,[11] which has resulted in most projects being focused on energy efficiency in

Figure 49 Number of projects and share of estimated GHG reduced



Source: UNFCCC Third Synthesis Report, FCCC/SB/1999/5

Table 31 Number of activities by type and region

Activity Type	Region				Total per type
	AFR	ASP	EIT	LAC	
Afforestation			1	1	2
Agriculture				2	2
Energy Efficiency	3	4	39	3	49
Forest Preservation		1	2	9	12
Fuel Switching			6	1	7
Fugitive Gas Capture			3	1	4
Renewable Energy	2	4	28	12	46
Total per Region	5	9	79	29	122

Source: UNFCCC Third Synthesis Report, FCCC/SB/1999/5/Add.1
The synthesis report is based on AIJ projects that have been reported to the UNFCCC by Designated National Authorities (DNA)
AFR = Africa, LAC = Latin America and Caribbean, ASP= Asia and Pacific, EIT = Economies in Transition
Bold Figures indicate the project type dominated in each region

economies such as China, Indonesia, Malaysia, and Thailand.

The success of the AIJ mechanism is dependent on the choice of targeted sectors. It has been argued that the projects that will prove most productive and successful are likely to be large-scale operating plants with high sensitivity to the value of avoided carbon emissions, such as power generation and transmission; industrial cogeneration; and industrial fossil fuel users.

AIJ EXPERIENCES

BENEFITS AND COSTS

POTENTIAL GLOBAL AND LOCAL BENEFITS

AIJ projects are an economic instrument to promote environmentally friendly investment by Annex I countries, and to assist them in meeting their UNFCCC obligations. The potential benefits to AIJ host countries include the kind of technology transfer that will both assist development and reduce greenhouse gas emissions. Local economic and environmental benefits include training, the construction of new and improved infrastructure and energy services to both urban and rural sectors, and improved energy supply security. This contributes to cost effective rural electrification and development. Host economy importation of advanced technologies will increase industrial competitiveness in domestic and international markets.

The UNFCCC Third Synthesis Report provides brief qualitative and quantitative information regarding environmental social/cultural and economic benefits. Nearly all Parties state benefits in each category, often including quantitative data for environmental benefits such as reductions in emissions of greenhouse gases, SO2, NOX and particulates. Fostering biodiversity, improving water and air quality and reducing erosion of hydrological resources are other environmental benefits mentioned. The majority of reports indicate social/cultural benefits, including active involvement of local communities, increased public awareness, and the maintenance of natural heritage and historical sites. Among the economic benefits are energy savings, an improved work environment and economic opportunities through the introduction of new technologies.

COSTS

The costs of AIJ implementation during pilot phase are not sufficiently reported due to inconsistencies in defining the costs of the AIJ component and other key data. Most data on costs, cost-effectiveness, and the amount of GHG abated remain at the level of estimates of varying accuracy because of uncertainties over procedures for setting baselines and conceptual issues. The draft revised Uniform Reporting Format (URF) addresses these issues and includes suggestions on how to improve the consistency in cost information and methodological approaches. These need to use the net present value (NPV) method for cost and revenue items in order to make data comparable and take into account effects such as inflation, interest rates, and purchasing power differences. In addition, costs reported were not defined in a harmonized fashion as project development costs; capital costs; implementation/installation costs; operation and maintenance costs, and other costs.

Table 32 shows the results of a UNEP costing study undertaken in Denmark that estimated the related cost in reduction options. The result of the study is consistent with Figure 48, which indicated that fugitive gas capture (FGC) demonstrated the lowest total average costs, closely followed by land use change and energy efficiency activities. The revenues generated from fuel saving accumulated, allowing project life total costs to come out as negative.

Table 32 CO_2 reduction options and related marginal abatement costs in Denmark

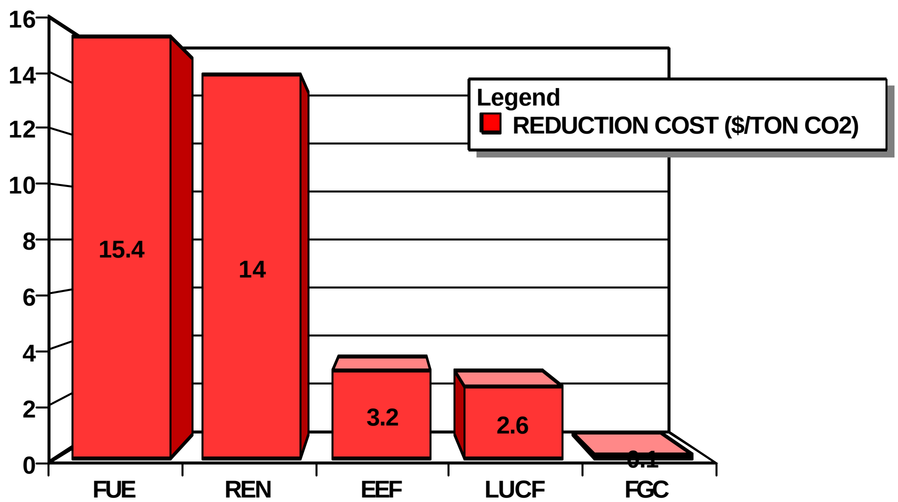
CO_2 reduction option	Reduction (%)	Marginal average cost ($/tonne CO_2)
Electricity conservation in households	4.8	-70
Conservation in industry	1.6	-40
Conservation in agriculture	0.4	-38.6
Combined cycle – natural gas (1000MW)	3.8	-8.6
Solar collectors for hot water (1500MW)	0.3	30
Photovoltaic (800 MW)	2.9	185.7

Source: UNEP, 1994.

TRANSACTION COSTS

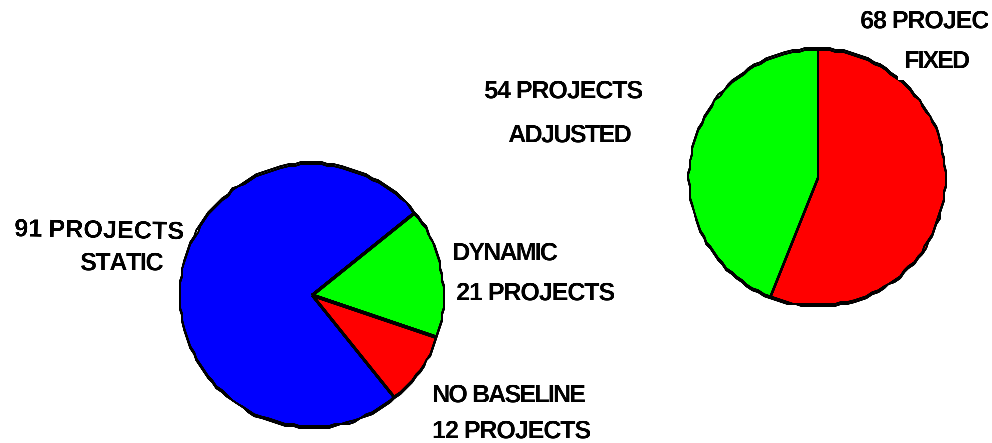
No cost figures were reported on transaction costs. However, some reports described the costs associated with the AIJ pilot phase to be relatively high at both macro- and project- levels. Some Parties indicated that transaction costs were incurred for: matchmaking between promoters and investors; awareness

Figure 50 Gross average reduction costs by activity-type (US$/ton CO_2)



Source: Schwarze, 1999

Figure 51 Evaluation of baseline according to investor economy



STATIC = unchanged over the lifetime of the project
DYNAMIC = models future energy & environmental trends, new technologies

Source: Michalelowa, 1999. Schwarze, 1999

raising on AIJ and the Convention; determining credible baselines; obtaining host and investor economy approval; additionality identification; and monitoring verification.[12]

It has been concluded that addressing these issues and setting clear guidelines and operational criteria for project identification (including baselines and additionality), reporting, monitoring and verification along with common terminology, would facilitate transparency and reduce transactions costs. This could be achieved by making information available on national approval procedures and project eligibility criteria.

LESSONS LEARNED

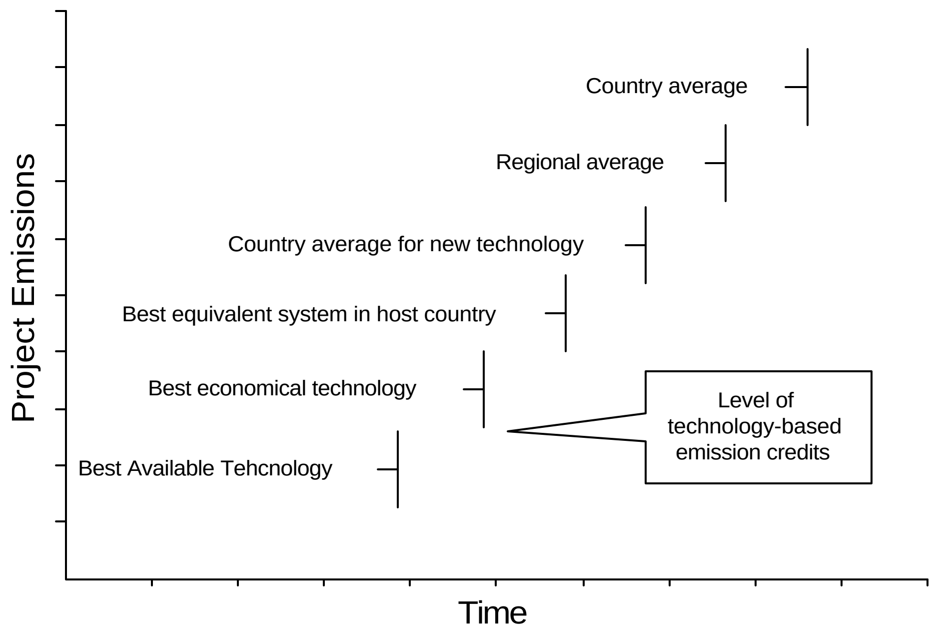
BASELINES

AIJ projects do not accrue emission credits, therefore emission baselines are only used as an indication of the real and measurable GHG mitigation effect for reporting back to the UNFCCC. Experience gained in baseline setting has been considered valuable however in identifying practicable and acceptable methodologies for CDM and JI projects.

Information on emission baselines in most reports is very limited and inconsistent. Most reports only provided inadequate descriptions of methodologies, baseline calculations, and assumptions. Baselines are also project-specific. There is no consistency in baseline setting, and even similar types of project had different input assumptions and different baselines.

The observed patterns of baseline assessment in AIJ projects can be simplified to static and a dynam-

Figure 52 Variations of crediting levels for a technology-based crediting system



Source: Ellis, 1999

ic baselines, and fixed and adjustable baselines. The static baseline results from an extrapolation of the status quo over the entire lifetime of a project, whereas a dynamic baseline is established by considering likely changes in technology, economic policy, behaviour, etc. A fixed baseline is a defined baseline which is valid over the entire project life, while an adjusted baseline will account for unforeseen developments that affect the reference and emission reductions are re-evaluated accordingly [Schwarze, 1999].

CREDITING MECHANISM

Technology-based emissions crediting could be one of the options used for some CDM projects. Though this system is subject to similar uncertainties and unresolved issues as project specific credits, it is simpler and cheaper for investors. The advantages and disadvantages of technology-based crediting were discussed in literature looking at emission baseline lessons from the AIJ pilot phase. The main advantage of a technology-based crediting system is the time saved in analysis, monitoring, and method development. This results in lower transaction costs, which is a barrier for small projects, therefore increasing the overall number of projects. In addition, this system can reduce the uncertainty of projects and help in initiation of projects where there is insufficient data to set up a meaningful project-specific emission baseline.

The disadvantage of this system is that only a few technologies, such as those based on renewable energy or more GHG-intensive projects, would be eligible for technology-based emissions credits because the reference scenario is required for environmental effectiveness measurement [Ellis, 1999]. Secondly, an international standard is required for a technology-based crediting system. It could be a time consuming and costly process to reach international agreement. There are several possible options available for technology-based credits, and the variations in credit levels (Figure 50). Besides setting the level of credits, other issues, similar to a project-based crediting system (including a validation period for the system and leakage) need to be resolved.

VERIFICATION AND CERTIFICATION

The verification procedure can be performed internally or externally. Most AIJ projects were verified externally because of strong support for this procedure in several national AIJ programmes. Most projects reported that the involvement of third parties in the verification process was complicated, involved high costs and left a number of issues relating to verification and certification processes unresolved. Experience from the ILUMEX Verification Pilot for UNFCCC [Telnes, 1999] outlines these issues as follows:

- Accreditation: Rules for approval of operational entities (third parties) offering validation, verification and certification services, registration of CERs, handling and time-limits for non-conformance situations, frequency of surveillance audits etc. all need to be decided upon, as well as the establishment of an accreditation authority.

- Conflicts of interest: There is a need for setting clear rules to avoid conflicts of interest for organisations involved in verification and certification of GHG projects: between project parties and validator, validator and verifier/certifier, project parties and verifier/certifier, certifiers involved in trade of CERs.

- The verification and certification process: The need for transparency of processes and transaction costs, the need for capacity building from the certification process itself, ways of reporting, enforcement of criteria, rules for handling situations where "non-direct" GHG criteria are not met by projects, all these are factors that must be evaluated and decided upon by the relevant authorities.

To address these issues, governments need to take a role in making decision with respect to preferred approaches and methodologies. Over time this can then establish a robust and suitable structure for verification and certification in CDM and JI projects.

FOCUS ON SHORT-TERM EMISSION REDUCTIONS

The African continent has been excluded from the AIJ pilot phase because of the emphasis on emission reductions. Africa is not in a position to benefit substantially because total emissions from the continent are almost negligible in global terms due to the low level of industrialisation. It is estimated that the entire continent contributes less than seven percent of global GHG emissions, and four percent of CO_2 emissions [UNDP, 1998a].

In Africa, AIJ projects are thought about in terms of avoided future emissions rather than emission reductions over the short-term. However, the UNFCCC emphasis on reduction commitments has become the default option in climate change-related projects because they are easier to quantify. As a result, countries that cannot contribute to emission reductions will not be targeted for such projects.

Endnotes

1 IEA definition of Activities Implemented Jointly partnership for climate and development: “It is a policy instrument to encourage investments in climate change mitigation technologies that also contribute towards local development and investment objectives of project-site countries.”

2 Central and eastern European countries and states of the former Soviet Union.

3 Decision 5/CP.1, UNFCCC Secretariat Report.

4 As outlined in Article 6 and Article 12 of the Kyoto Protocol.

5 Decision 6/ CP.4.

6 The governments that accept, approve, or endorse the activities, sign the “Letter of Intent.”

7 The projects have been accepted, approved or endorsed by the designated national authorities for AIJ of the Parties concerned.

8 The listed of reported projects and brief descriptions can be found in UNFCCC website.

9 Currently, the national programmes of the following countries are listed on the UNFCCC website: Costa Rica, United States, Japan, Norway, Poland, Sweden, Switzerland.

10 AIJ National Programme of COSTA RICA. http://www.unfccc.de/program/aij/aijprog/aij_pcri.html.

11 The Government of Japan stated in JIQ, 1996 that “the role of Japan is to share technologies with other countries, especially with Asian economies” (Matsuo, 1996).

12 Latter two costs will be allocated as production costs in CDM projects.