ASIA PACIFIC ENERGY RESEARCH CENTRE

ENERGY SUPPLY INFRASTRUCTURE DEVELOPMENT IN THE APEC REGION

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Asia Pacific Energy Research Centre
Institute of Energy Economics, Japan
Shuwa-Kamiyacho Building, 4-3-13 Toranomon
Minato-ku, Tokyo 105-0001 Japan
Tel: (813) 5401-4551
Fax: (813) 5401-4555
Email: okano@aperc.ieej.or.jp (administration)

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FOREWORD

I am pleased to present the final report of the study, Energy Supply Infrastructure Development in the APEC Region. This study is a follow-up of three previous studies undertaken by APERC, namely; Natural Gas Pipeline Development in Northeast Asia, Natural Gas Pipeline Development in Southeast Asia, and Power Interconnection in the APEC Region that were completed in March 2000.

This merged study was initiated because energy infrastructure interconnections issues have become high on the energy policy agenda of most APEC economies, both developed and developing.

The principal findings of the study are highlighted in the executive summary of this report.

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

We also thank all members of the APEC Energy Working Group (EWG), APEC Expert Group on Energy Data and Analysis (EGEDA), APERC Advisory Board, energy officials and other experts 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.

PROJECT LEADER:

Dr Hassan Ibrahim (Malaysia)

PROJECT PARTICIPANTS:

Ahmad Haji Mohamad (Brunei Darussalam)
Zhong-an Wang (China)
Iman Santoso (Indonesia)
Satya Zulfanitra (Indonesia)
Naoko Doi (Japan)
Dr Ki Joong Kim (Korea)
Martin Bonou (Papua New Guinea)
Edito Barcelona (Philippines)
Dr Oleg Sinyugin (Russia)
Dr Tran Thanh Lien (Viet Nam)

EDITOR

Dr David Cope (New Zealand)

ADMINISTRATIVE SUPPORT

Sutemi Arikawa, Shohei Okano, Sachi Goto, Emi Tomita, Yayoi Ito, and Erika Saeki.

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ABARE	Australian Bureau of Agricultural and Resource Economic
AC	Alternating current
ACE	ASEAN Centre for Energy
AEEMTRC	ASEAN-EC Energy Management Training and Research Centre
APEC	Asia Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASCOPE	ASEAN Council on Petroleum
ASEAN	Association of Southeast Asian Nations
B98	Baseline-1998 Scenario
BAU	Business-as-usual
BCF	Billion cubic feet
BCM	Billion cubic metres
BCMY	Billion cubic metres per year
BP	British Petroleum
BTU	British thermal unit
CCGT	Combined cycle gas turbine
CEERD	Centre for Energy-Environment R&D - Asian Institute of Technology
CIGRE	Conference Internationale des Grands Reseaux Electriques
CLP	China Light and Power Company
CNPC	China National Petroleum Corporation
CO2	Carbon dioxide
DC	direct current
DPRK	Democratic People's Republic of Korea (or North Korea)
EDF	Electricite de France
EDMC	Energy Data and Modelling Centre (Japan)
EFS	Environmentally Friendly Scenario
EGAT	Electricity Generating Authority of Thailand
EGEAS	Electric Generation Expansion Analysis System
EIA	Energy Information Administration (USA)
EPDC	Electric Power Development Company (Japan)
EPRI	Electric Power Research Institute
EPS	Electric Power System
ES	Energy System
ESPRIT	Electric System Planning Program Reflecting Interconnection & Transmission
EU	European Union
EVSL	Early Voluntary Sectorial Liberalisation
EWG	Energy Working Group
FERC	Federal Energy Regulatory Commission (USA)
FGD	fuel gas desulphurised
GDF	Gaz de France
GDP	Gross domestic product
GHG	Greenhouse gas
GJ	Gigajoules
GMS	Great Mekong Sub-region
GVA	Gross Value Added
GW	Gigawatt (= one million kilowatt)
GWh	Gigawatt hour (= one million kilowatt hours)
HAPUA	Heads of ASEAN Power Utilities/Authorities
HVAC	High voltage alternating current
HVDC	High voltage direct current
Hz	Hertz

IAEA	International Atomic Energy Agency
IE	Institute of Energy (Viet Nam)
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IPPs	Independent power producers
IPS	Interconnected power system
JDA	Joint Development Authority (Malaysia - Thailand)
KEDO	Korean Peninsula Energy Development Organisation
km	Kilometre
KOGAS	Korea Gas Company
ktoe	Kilo-tonnes of oil equivalent
kV	kilovolt
kW	kilowatt
KWh	kilowatt hour
LA	Loan agreement
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LRMC	Long-run marginal cost
mcf	million cubic feet
MFV	Modified fixed variable
MMBOE	Million barrels of oil equivalent
MMBTU	Million British thermal units
MMCM	Million cubic metres
MMCMD	Million cubic metres per day
MMCMY	Million cubic metres per year
MMSCFD	Million standard cubic feet per day
MOU	Memorandum of Understanding
Mt	Million tonnes
MT-JDA	Malaysia-Thailand Joint Development Area
Mtoe	Million tonnes of oil equivalent
MVA	mega volt amp
MW	Megawatts (= 1,000 kilowatts)
MWh	Megawatt-hour (= 1,000 kilowatt-hours)
N2O	Nitrous oxide
NGV	Natural gas vehicle
NORDEL	Nordic Electricity Grid
NOX	Nitrogen oxides
NRE	New and renewable energy
OPEC	Organisation of Petroleum Exporting Countries
PCS	Protracted Crisis Scenario
PCS	Protracted Crisis Scenario
PDP	Power Development Planning
PDR (Lao)	Lao People's Democratic Republic
PERTAMINA	National Petroleum Company of Indonesia
PETRONAS	National Petroleum Company of Malaysia
PGN	Perum Gas Negara Ltd (Indonesia)
PGU	Peninsular Gas Utilisation
PNG	Papua New Guinea
PSA	Production sharing agreement
PTT	Petroleum Authority of Thailand
RAO	Russian Joint Stock Company
ROK	Republic of Korea (or South Korea)
SCGT	simple cycle gas turbine

SFV	Straight fixed variable
SMNG	Sakhalinmorneftegas (Russia)
SO2	Sulphur dioxide
SOX	Sulphur oxides
SP	Singapore Power
SRM	short-run marginal cost
TAGP	Trans-ASEAN Gas Pipeline
TAPG	Trans-ASEAN Power Grid
TCF	Trillion cubic feet
TCM	Trillion cubic meter
TECO	Tri Energy Co., Ltd **
TEPCO	Tokyo Electric Power Company
TFEC	Total final energy consumption
TNB	Tenaga Nasional Berhad, Malaysia
toe	Tonne of oil equivalent
TPA	Third-party access
TPEC	Total primary energy consumption
TPES	total primary energy supply
TWh	Trillion watt-hour
UCPTE	Union for the Co-ordination of Production and Transmission of Electricity
UES	United Energy System
UESR	United Energy System of Russia
UK	United Kingdom
UN	United Nations
UNTAET	United Nations Transitional Administration for East Timor
UPS	Unified Power System
US	United State
US-DOE	United State Department Of Energy
WASP	Wien Automatic System Planning Package
WCSB	Western Canadian Sedimentary Basin
WIGPLAN	Westinghouse Interactive Generation Planning Model
YPEPC	Yunnan Provincial Electric Power Corporation (China)

PREFACE

The objectives of this study are:

- To investigate the merits, complementarity and competition between natural gas pipeline and power grid interconnection;

- To identify critical factors and issues in the choice and development of energy infrastructure networks;

- To investigate the latest plan and development of energy infrastructure linkages in Northeast and Southeast Asia.

RATIONALE OF THE STUDY

The study is conducted with the following rationale:

- Rapid growth in electricity demand is a challenge in the APEC region.

- Large-scale natural gas resources are present along with other abundant energy resources for power generation in the APEC region. This is leading to a number of plans within Northeast and Southeast Asian APEC member economies for the development of a region-wide gas pipeline network.

- The growing trend of energy sector reform and liberalisation, including an initiative for Early Voluntary Sectoral Liberalisation (EVSL) of trade, may facilitate and accelerate regional natural gas and electricity trade through gas and electricity interconnections.

- Natural gas pipeline and power interconnections are important policy goals for APEC economies, and the merits of one versus the other needs further investigation.

- APERC completed the previous three energy infrastructure studies in March 2000. Two investigated natural gas infrastructure development (in Northeast and Southeast Asia), and one investigated power grid interconnections. These studies have served as a basis for a study that merges the two themes into a combined analysis.

SCOPE OF THE STUDY

- In this study, Northeast Asia covers China, Japan, Korea and Russia. Southeast Asia predominantly covers the APEC members of the Association of Southeast Asian Nations (ASEAN): Brunei Darussalam, Indonesia, Malaysia, Philippines, Singapore, Thailand and Viet Nam - with some references to their neighbours, Cambodia, Laos PDR and Myanmar.

- The study also includes some discussions on energy infrastructure projects in Papua New Guinea.

The discussion on natural gas infrastructure development is limited to gas pipelines only. However, LNG development is briefly touched in Chapter 2 of the report.

EXECUTIVE SUMMARY

GENERAL SUMMARY

The objectives of this study are: i) to investigate the merits, complementarity and competition between natural gas pipeline and power grid interconnections; ii) to identify critical factors and issues in the choice and development of energy infrastructure network; and iii) to investigate the latest plans and developments of energy infrastructure linkages in Northeast and Southeast Asia.

This study is a progression of three studies conducted in 1999/2000 that focused on regional power interconnections and the development of large-scale natural gas pipe networks, for supplying the APEC region. The current study also focuses on Northeast and Southeast Asia. The Northeast and Southeast Asia regions present some key differences in characteristics as far as gas and electricity supply and demand as well as infrastructure developments are concerned.

It is hoped that this report will assist energy planners in dealing with issues related to the integration of energy networks with neighbouring economies as part of a strategy to enhance energy supply security and promote bilateral or regional energy-trade.

Energy infrastructure networks enhance the security, flexibility and quality of energy supply among the interconnected economies. They act as an impetus to economic growth and encourage energy cooperation among energy exporting and importing economies. Transit economies, that is economies that provide facilities for the laying-out of the infrastructure in their territories, also benefit from the rights-of-way given to the energy transmission.

The reform process of the gas industry and deregulation of the power industry occurring in many APEC economies has led to the convergence of supply services for both network industries. This is brought about by market development as well as the operational similarities between gas and electricity.

In the power generation industry, the highly efficient combined-cycle gas turbine (CCGT), with its relatively short construction timeframe and adaptability to either base or peak load operations, has become the main reason for the increasing popularity of gas as a fuel.

Despite the link with crude oil prices, natural gas prices have remained competitive. As a premium fuel, any additional costs over fuel oil or coal are compensated by its environmental benefits.

Natural gas pipeline interconnections and electricity grid interconnections in the region tend to complement each other, rather than directly compete. Each energy source has its own benefits, and the interconnection decision making process is driven more by local conditions than real choice between competing options.

Natural gas can bring significant benefits to consumers and to the region, whether used to generate electricity or provide other services, such as end-use cooking and heating/cooling. Pipeline infrastructure is a pre-requisite to natural gas playing a greater role in the region.

Three major factors favour and motivate power interconnections. These are security of supply, economic efficiency and environmental impacts. Currently, the first two factors are the major driving forces for interconnection of power systems in the APEC region. However, increasing concern over air pollution at local, regional and global levels - especially CO_2 emissions - will induce the power sector to seek cleaner and more environmentally friendly alternative energy supplies. In this regard, environmental protection could become an important factor in decision making for cross border power interconnection projects.

Traditional thinking has favoured the importation of gas over electricity, because of the value-added benefits. However, other factors must also be considered, and this has led to a number of power interconnections in the region. Usually, this has occurred where relatively low cost hydropower is available, and is in excess of the requirements of the economy in which it is found.

In Asia, the distribution of resources in comparison to demand is such that a number of interconnection projects can be envisaged that would provide obvious regional benefits. Resource rich economies tend to have relatively low demand, whereas neighbouring resource poor economies have high demand. The barriers to development of regional energy networks are geopolitical and geographical, and although not insurmountable, are definitely problematic.

In Northeast Asia, Russia is well endowed with both natural gas and hydropower resources, especially around Irkutsk and Sakhalin. Japan and Korea, both of which are LNG importers, require additional natural gas to meet growing domestic demand for clean energy. China, which for decades has been highly dependent on coal, is now putting in place the policy changes needed to encourage natural gas and other cleaner fuels.

Proposals for gas pipeline and power interconnection projects between Irkutsk and Beijing have been on the drawing board for years. If such a pipeline were in place, it is not too difficult to imagine it extending all the way to Korea and Japan (feeding centres of demand along the way). The Sakhalin - China and Sakhalin - Japan proposals offer other options.

In Southeast Asia, except for Singapore with no significant indigenous energy resources, all economies are endowed with energy resources of one type or another, but in varying degrees of abundance. Physical distances between energy resources and demand centres are one of the key factors in determining interconnection decisions. The cost of the infrastructure per kilometre is the single most important factor determining the economic viability of such projects.

Southeast Asia has two sub-regions of net energy exporters and net importers in close proximity to each other. The first is the Greater Mekong Sub-region (GMS) which includes Cambodia, the Yunan province of southern China, Laos PDR, Myanmar, Thailand and Viet Nam. The second one is Borneo Island consisting of Brunei Darussalam, Indonesia (Kalimantan) and East Malaysia (Sabah and Sarawak).

In Greater Mekong, Thailand is a net energy importer, and has enjoyed rapid economic growth, so is a natural power sink with its hydropower rich neighbours acting as power sources. With adequate infrastructure in place in the future it may be possible for hydropower to be wheeled further south to Peninsular Malaysia and Singapore.

Gas pipeline interconnections in this sub-region are reasonably well developed. Three cross-border pipelines (Peninsular Malaysia - Singapore, Myanmar - Thailand and West Natuna - Singapore) are already operating. One pipeline (Trans Thailand - Malaysia) is under construction and two more (Sumatra - Singapore and West Natuna - Peninsular Malaysia) will soon be constructed with the gas purchase contracts recently signed by the respective parties. Although at the moment these major pipelines are not connected to one another, future domestic networks, such as Malaysia's Peninsular Gas Utilisation pipelines could have some (if not all) cross-border pipelines interconnected at some stage. More widespread interconnections could lead to and facilitate open gas markets in the region in the future.

In Southeast Asia, strong economic growth helped by the relatively close distance between resources and markets have been the key determinants in the development of a number of cross-border infrastructures. Firm political and government backing with vision, targets and objectives being clearly stated in the ASEAN Head of Governments Meetings and ASEAN Energy Ministers Meetings have also encouraged speedier development of such infrastructure. Follow-up strategies are further discussed in ASEAN Senior Officials on Energy Meetings, and meetings among the region's state-owned oil and gas companies (ASEAN Council on Petroleum - ASCOPE) and power utility companies (Head of ASEAN Power Utilities/Authorities - HAPUA).

In Northeast Asia, the long distances between the energy resources and markets are a major hurdle to the development of energy interconnections, although some concrete plans and routes have been proposed. Furthermore, the lack of a consolidated regional cooperation framework (of equal significance to that in Southeast Asia) among the respective economies may have also contributed to a delay of getting consensus among the involved parties. The APEC mechanism should therefore be used as an impetus to trigger more deliberations and planning among respective bodies within Northeast Asia to enhance further energy and economic cooperation among the respective economies.

In the long term, the prospects for sub regional or even regional energy networks are quite good. The Trans-ASEAN Gas Pipeline (TAGP), long an aspiration in Southeast Asia, is actually being realised as a step-by-step development of cross-border connections. Australia and Papua New Guinea are also considering a pipeline link with gas flowing from Papua New Guinea to Australia (refer to Chapter 7). One or more pipeline linkages may eventually be realised with Russia transporting gas to China or Japan and further on to Korea, depending on the pipeline route taken, in the not so distant future. ASCOPE is also planning to look into the possibility of a natural gas pipeline from the Natuna East reserves, Southeast Asia's biggest gas resource area, to China with the possibility of exports to Korea and Japan.

SUMMARY OF POLICY IMPLICATIONS

Summarised below are the potential barriers to overcome or agendas that have to be resolved in order to reap the benefits of trans-border gas pipeline and power grid interconnections.

The full potential of benefits of energy interconnections must be understood and encouraged if the full benefits are to be realised. Some electricity interconnections are designed to only import power during periods of high demand or local disruption. However, the full environmental and economic benefits of a power interconnection are realised in situations where there is daily two-way flow of electricity to meet varying peak load demands in each economy.

Geopolitical differences and conflicts are a major regional impediment to cross-border energy infrastructure development. Areas with known hydrocarbon and other energy resources that cannot be developed because of territorial disputes only deprive the region of additional energy supply security. An obvious solution is for economies to agree on developing those resources together as a consortium, with an agreed profit sharing split.

Transparency of rules and regulations must be established and maintained in any joint project. Where rules and regulations with regards to energy trade and pricing are different, they must first be harmonised. Where subsidies are still required for social reasons, they need to be transparent and explicitly targeted. With all pipeline infrastructure investments now expected to be driven by the private sector, transparent tariff systems for production, transmission and distribution are required to assist investors in fairly estimating risks.

When a pipeline or transmission line has to pass through one or more economies, transit rights and transit fees have to be clearly settled to avoid future conflicts that could threaten the flow of energy. No international agreements, such as the European Energy Charter, exist as yet in the Asia-Pacific region - negotiations of a similar accord should be considered under which gas or electricity transit can be codified.

CHAPTER 1

INTRODUCTION

Rapid growth in energy demand in the Asia Pacific, a region where energy resources and centres of demand are often unevenly balanced, has led to the need for innovative solutions to address the challenging problem of energy supply. An obvious solution is regional trade in energy - natural gas and electricity - not traditionally traded in large quantities across the border because of the logistic and cost problems associated with transport. Ignoring LNG for the moment (one innovative solution to the transport of natural gas), the extension of gas and electricity grid networks cross-border is still in the formative stages of development, and important technical and political questions need to be addressed as this trend develops further.

For example, how does a cross-border gas or electricity connection affect the energy security of an economy? How much must be done to harmonise standards? What are the pipeline network access rules and what are the policies governing investment in network infrastructure? Is there competition or complementary between imported gas and electricity?

Cross-border energy networks which currently exist in Southeast Asia link neighbouring economies. As yet there is no regional network transiting through intermediate regions. At this stage, there are no binding agreements, such as the European Energy Charter, which binds all involved parties to safeguard their interests and the interests of investors. This is currently a hurdle faced by decision makers in trying to promote links such as the Irkutsk-Beijing interconnection (around 2,600 km), and which would have to be extended by 1,500 km if it were to avoid the territory of a third economy.

Traditionally, the importation of natural gas has been viewed more favourably than imported electricity, because further value could be added in the importing economy. Energy exporters on the other hand, have been keen to export electricity where possible. In reality, the individual situation dictates what is most beneficial to both parties, as other determining factors must be considered.

Natural gas, being the cleanest fossil fuel for power generation, is also used as a cogeneration fuel in industrial applications, as a fuel for domestic cooking and heating, and as a feedstock for industrial processes. In some cases, the most immediate demand is for electricity, so the importation of electricity makes sense for some economies.

Power grid interconnections enhance supply reliability, peak load control, and also improve the opportunities for capturing economies of scale in some instances. Furthermore, a power interconnection may lead to CO_2 emission reductions for some economies otherwise reliant on fossil fuels such as coal and oil.

This study is a follow-up to three studies completed by APERC in 2000: *Natural Gas Infrastructure Development in Northeast Asia*, *Natural Gas Infrastructure Development in Southeast Asia*, and *Power Interconnections in the APEC Region* [APERC, 2000a; APERC, 2000b; and APERC, 2000c]. Additional details about the infrastructure development in Northeast Asia and Southeast Asia are found in these three reports. These earlier reports also included some analysis on the historical trend and forecasts of electricity and natural gas demand. It is therefore recommended that these three reports be studied as a pre-requisite before reading this report. All APERC's project reports are accessible on the APERC website (http://www..ieej.or..jp/aperc/).

CHAPTER 2

ENERGY INFRASTRUCTURE TRENDS

Energy demand has grown rapidly during the last two decades resulting in increasing energy sector trade and services within the Asia Pacific region. International trading of energy commodities - vital to economic and social development - has been facilitated by discoveries of large-scale energy resources geographically close to large-scale demand centres.

Broadly speaking, in the western Pacific Rim the large-scale energy resources most readily accessible to large markets are located in the south (Southeast Asia and Australia), and the north (Russia and the Former Soviet Union states), and the centres of demand are in the centre. Currently, the centres of demand are reliant largely on imported energy (Japan, Korea and Chinese Taipei) and draw their non-oil energy supplies (coal and natural gas) from Southeast Asia and the Pacific.

As the wealthier economies in Asia have sought over the last two decades to lessen their dependence on crude oil - and in particular oil sourced from the Middle East - the technology needed to extract and transport fuels such as coal and natural gas has improved. For natural gas, transportation is a major factor in getting it to distant markets, and so long-range pipelines and LNG processing facilities have become important elements in the marketing of this fuel.

Because of the distances between gas resources and markets in Asia, LNG has long been favoured as the most economic method of gas transportation. As natural gas producers such as Indonesia, Malaysia and Brunei Darussalam develop economically and socially, along with nearby neighbours, the local demand for natural gas has increased. To meet this demand, domestic and local cross-border gas transmission networks have begun to develop, and plans exist to extend these networks further.

This trend is leading to a number of effects: the price of natural gas is being forced up by competing sources of demand, new exploration activities are being financed, and plans for extending pipelines into a regional network are being promoted. Apart from rising demand, the price of natural gas has also been dragged upwards by LNG prices which rose with crude oil prices. This activity has also changed the power industry. As the power generation sector is the major market for natural gas, the option of generating power close to the location of energy resources and exporting the power is becoming an attractive proposition to meet the burgeoning regional demand for electricity.

This chapter provides an overview of natural gas and power interconnection trends in the Asia-Pacific. The benefits of energy infrastructure interconnection, including benefits related to energy supply security and the environment are discussed. An overview of infrastructure interconnection development in North America and Western Europe are also discussed as useful background to this study. The chapter also highlights current activities in the energy supply industry, in particular the convergence and merging of gas and power utility services. LNG as a competing means of natural gas transportation is also included at the end of the chapter.

Advantages of natural gas pipeline interconnection

Natural gas is relatively clean environmentally and requires minimal processing prior to use. It possesses high thermal efficiency. Natural gas use can bring significant benefits to the consumers and the region. Natural gas pipelines provide the necessary infrastructure to move gas from the field to the market. Pipeline infrastructure is a pre-requisite for moving Northeast and Southeast Asian natural gas to markets, along with LNG infrastructure, allowing gas to play a greater role in the energy supply security of the region as well as mitigating greenhouse gas emissions from energy use.

Advantages of power grid interconnection

Three major factors favour and motivate power interconnection. These are security of supply, economic efficiency and environmental protection. Currently, the first two factors are observed to be the major driving forces for interconnection of power systems in the APEC region. However, increasing concern about air pollution at local, regional and global levels, especially CO_2 emissions, will induce the power sector to seek cleaner and more environmentally friendly alternative supplies. In this regard, environmental protection could become an important factor in decision making for cross border power interconnection projects.

POTENTIAL BENEFITS

The benefits of natural gas pipeline and power grid interconnections were analysed in previous APERC studies published in March 2000 [APERC, 2000b; APERC, 2000c]. These studies concluded that the benefits were as follows:

The Australian Bureau of Agricultural and Resource Economics (ABARE) has identified five main economic benefits arising from interstate gas or electricity connection. Australia is a federal economy consisting of six states, each state possessing its own natural gas and electricity commissions and operating its utility companies differently from one another. Except for the sovereignty issues that arise in international trade in electricity, the economic benefits arising from inter-state interconnections in Australia are little different from regional or cross-border interconnections between APEC economies.

The Directorate-General for Energy of the European Commission also specifically explained the benefits of their energy networks (principally natural gas and electricity). The European Union consists of 15 member countries, and its Trans-European energy networks consist of natural gas and electricity networks linking nearly all of the member economies.

Christos Papoutsis, the European Commissioner for Energy, described the benefits of the Trans-European Energy Networks as follows:

The five benefits of power interconnection (from ABARE):

1. Interconnections can improve the efficiency of resource allocation. If production costs differ between states, interstate trade in electricity or gas can have economic benefits as long as the price differentials are sufficient to repay the investment, operating and maintenance costs of interconnecting the grids or pipelines.

2. In the case of electricity interconnections - economic benefits may arise from complementarities between state systems. Electric power is difficult to store, and demand is highly variable. Some electricity production methods, such as hydroelectric generation, can respond quickly to changes in demand; others such as thermal coal stations, although slower in response are relatively cheaper for base load supplies. Interconnection between systems based on different technologies can therefore increase flexibility and reduce costs.

3. Benefits can be derived from the deferral of new plant investment. To maintain power supply, electricity authorities need to have excess capacity (reserve plant margin) to provide both foreseen and unforeseen station downtime. Interconnection of state grids would allow the necessary excess capacity to be shared between states and thus reduce total capital requirements.

4. Supply of gas from interstate sources can in some locations add to the choice of fuels for electricity generation. In addition, gas and electricity can compete in many end uses.

5. Economic benefits can arise from the greater competition between suppliers possible in a larger interconnection network.

“The Trans-European Energy Networks are of the greatest importance for Europe's economy and for the security of its energy supplies.

Network development improves the operation of the energy networks (principally, gas and electricity) by enhancing the security, flexibility and quality of the Union's energy supply, which benefits all our citizens.

Network development can, especially by enhanced competition and economics of scale, reduce energy costs, which in turn can - because energy is a major input to industry -improve our competitiveness on the world's markets and thus contribute to economic growth and job creation.

By developing the energy networks so as to diversify the routes and sources of the energy that reaches us from outside the Union, we can achieve greater security and less dependency on a given external supplier.

We can, by developing the energy networks, help to reduce the effects of isolation for less advantaged regions, improving their access to different energy sources at competitive prices, thus increasing economic and social cohesion [EU, 1997].”

NATURAL GAS VS POWER GRID INTERCONNECTION

When both natural gas and electricity are available in a domestic market, it can be argued that they are actively competing commodities. The extent of this competition at the domestic level is actually rather limited, and is heavily dependent on the availability of the infrastructure required to make both gas and electricity available to domestic consumers at prices conducive to encourage competition. Even then, competition is limited to home heating and cooking demands, the former not particularly important in the warmer Asian climate.

At the wholesale level at which cross-border natural gas and electricity transmission grids are likely to be competing with indigenous energy resources, is this competition between commodities an important issue?

The power sector is the key market for natural gas, especially in developing economies where other potential markets are poorly developed. Investors in natural gas infrastructure need large-scale power generation customers in order to justify the cost of pipeline construction. Once these customers are signed up, others will eventually follow, industries that can use natural gas as a fuel or as a feedstock, the commercial sector, and finally domestic consumers. Domestic consumers are last because they typically account for less than 5 percent of gas demand, because gas distribution networks are expensive to install, and investors in less developed economies have a limited ability to recover the costs of the infrastructure development.

The development of cross-border energy infrastructure will be driven by a number of important factors, and these will determine whether it will be gas, electricity, or both. The important factors will be: location and extent of energy resources; location, relative wealth, level of industrialisation and density of markets; political relationships between neighbouring economies; technical and geographic barriers; and investor confidence.

For example, Singapore currently imports a limited amount of natural gas from Malaysia to co-fire an oil-fired power station located on the northern part of the island. Although the gas imports are not sufficient for other purposes, the short length of cross-border pipeline required made this an economic proposition. Since January 2001, Singapore has been importing gas from West Natuna (in Indonesian waters) to the southern part of the island, where it is used for power generation and industrial and commercial uses. Because of local geopolitics, such an arrangement is more attractive to Singapore than the importation of electricity.

On the other hand, Thailand imports relatively inexpensive hydropower from Laos and natural gas for power generation from Myanmar. Both these arrangements make commercial sense, as both Laos and Myanmar have limited local demand for energy, and a considerable need for foreign exchange earnings.

COMPETITION BETWEEN CENTRALISED AND DISTRIBUTED TECHNOLOGIES

In developed APEC economies, there is an emerging trend away from large centralised base-load power stations feeding extensive transmission and distribution networks, and towards greater distribution of power generation sources, usually located in close proximity to centres of demand [Awerbuch *et al*, 1999]. In theory, a fully distributed power system could operate independently of a power transmission grid, although in practice this is unlikely to be the case, except for remote power systems.

Distributed technologies represent a group of modular, smaller-scale technologies capable of being operated at, or perhaps, near the intended load. They would normally comprise power systems driven by renewable sources of energy (such as mini or micro-hydropower, wind turbines, photovoltaics and fuel cells), or by natural gas (micro and mini-turbines, reciprocating engines, and fuel cells).

"Distributed" does not necessarily mean that the load or the technology is not connected to the grid. Rather, it means that any power produced by the modular technology would largely displace transmitted power. This system differs from the historic idea of diesel-powered back-up generators, because in a distributed power system, the individual small-scale generation units provide either base-load or peaking load on a regular basis, and the small-scale producer may even sell power back into the distribution network. In systems where transmission capacity has become a constraint (true in many developed economies), this trend avoids the need for costly grid upgrading, and provides the transmission and distribution lines owners with a certain level of competition.

In the United States, in 1997, the installed capacity of small-scale and co-generation was 9.5 percent of total installed generation capacity. The growth of distributed power systems (including co-generation units and small-scale generation facilities) increased by 73 percent between 1990 (42,870 MW) and 1997 (74,021 MW). Projections made by Awerbuch *et al* (1999) over the 40 years predict an annual growth rate of 5.0 percent for distributed technologies, compared to 1.5 percent for the total electric market - with the total market nearly doubling over 40 years [Awerbuch *et al*, 1999].

INTER-FUEL COMPETITION IN THE POWER GENERATION INDUSTRY

Because of its availability, competitiveness and relatively low pollutant emission levels, natural gas has been gradually replacing fuel oil and coal as a favoured fuel for power generation. *The APEC Energy Demand and Supply Outlook* predicted that gas consumption for the whole of the APEC region will increase 63 percent (3.3 percent per annum), from 770 Mtoe in 1995 to 1,253 Mtoe in 2010, more than twice the rise from 1980 to 1995 [APERC, 1999]. For coal and oil, the increase in consumption over the same period is 41 percent (2.3 percent per annum) and 34 percent (2.0 percent per annum) respectively.

In Southeast Asia, growth in natural gas consumption for power generation has been particularly impressive. In Malaysia, for example, the share of total annual fuel consumption provided by natural gas in 1986 was 22.3 percent, compared to 77.7 percent for oil (fuel oil and diesel). In 1998, as shown in Table 9, the fuel scenario had reversed, with gas taking the dominant share at 69.8 percent, and oil at 19.7 percent. For Indonesia also, the natural gas share in 1986 was 4.4 percent compared to oil and coal at 70.2 percent and 25.4 percent, respectively [AEEMTRC, 1998]. By 1998, most of the oil consumption had been replaced by natural gas, with some percentage also going to coal - specifically, 32.2 percent for natural gas, 29.3 percent for coal, and 18.2 percent for oil.

FUEL PROCUREMENT FOR ELECTRICITY GENERATION

The generation of electricity accounts for more than one third of primary energy consumption in most APEC economies. Coal has traditionally been one of the most popular power generation fuels, but natural gas has become increasingly important with the development of the combined cycle gas turbine. This development has been stimulated by the regional abundance of natural gas.

CCGT technology has a number of advantages. Firstly, thermal efficiency is as high as 55 percent and is expected to reach 60 percent by 2010. Power generation units are less capital intensive than coal-fired plants of similar capacity, and construction times are faster. As an example, it took only about 20 months to construct a 1,800 MW CCGT power plant in Teesside in the UK.

Table 1 Gaseous emissions from fossil-fuelled power plants

	SO_2	NO_X (gm/kWh)	CO_2	Thermal efficiency
Gas (combined cycle)	~0	0.5-2	370	50-55%
Integrated gasification combined cycle	0.1-1	0.5-1	790	42%
Oil (combined cycle)	1-2	2-3	540	49%
Coal (pulverised)	8-20	3-5	860	37%
Coal (w/scrubber)	1-2	4.7	880	36%

Source: APERC, Natural Gas Infrastructure Development: Southeast Asia, 2000.

Compared to power generation using simple cycle gas turbine (SCGT, with plant efficiency of 36 percent), a typical 700 MW CCGT plant can provide savings in excess of US$ 1 billion over the 25 years of the plant life [Howard, 1999].

Emissions are lower for natural gas than for power generated using more carbon intensive fossil fuels. SO_2 emissions are negligible and NOx emissions low (six to ten times lower than those of coal-fired plants depending on plant design). Carbon dioxide emissions are about half those of a typical coal-fired power plant of similar capacity, and 30 percent lower than those produced by an oil-fired plant.

Another advantage of CCGT plants lies in plant operation. It takes a CCGT plant 15 to 20 minutes to reach normal generating capacity from cold start-up. The required amount of cooling water is also less than for other types of thermal plant due to the fact that around one-third of the electricity is generated by steam turbines using waste heat from the gas turbines. Since CCGT power stations require less land for siting, environmental impacts are lower. Operational simplicity allows for lower operating costs.

An important contributing factor leading to increased investment in gas-fired power generation plant has been the worldwide trend of deregulation and market liberalisation. In the early 1990s in Europe, the European Union repealed the 1975 directive prohibiting the use of natural gas for power generation and, consequently precipitated a surge in investment in gas-fired generation. Restructuring in the power generation market allowed IPPs to compete with the generation arms of existing electric utilities, resulting in the rapid construction of gas-fired plants with lower capital and operating costs for a given level of electricity output.

HORIZONTAL DIVERSIFICATION

The deregulation and privatisation of the energy network industries has led to a significant degree of consolidation of ownership of network assets. It is increasingly common to see separate gas and electricity network owners merging into single network companies, possibly with generation capacity, but depending on the degree to which regulatory controls limit the degree of consolidation of natural monopoly and competitive elements of the energy supply industry.

It is a general phenomenon by now in the US and the UK to see companies that supply both electricity and gas. In France, EDF (Electricite de France) and GDF (Gaz de France) share an integrated marketing unit to supply both electricity and gas.

In some cases, combined utilities market gas and electricity under different trading arms, to maintain at least the illusion of competition between these two energy commodities.

CONVERGENCE OF ELECTRICITY AND GAS SUPPLY INDUSTRIES

In the US, there has been a growing number of electricity and natural gas supply companies combining services due to the increased competition resulting from liberalisation and privatisation in the energy industry. Convergence is driven by the desire of companies to improve efficiency and diversify products and services, as well as promote the use of natural gas for power generation [EIA, 1999]. Likewise, by merging, companies can share expertise and experience in the energy market.

The convergence of natural gas producers and pipeline companies with electricity generators assures natural gas supply for power plants. New power plants can be strategically built relative to natural gas pipeline routes.

From 1997 through April 2000 in the US, 23 mergers between natural gas and electricity supply companies (with a total asset value of at least US$ 0.5 billion) have been completed or were currently being planned. This trend could be expected to continue with increasing competition in the electricity supply industry.

As deregulation and privatisation of energy industries becomes more widespread in Asia, where natural gas is emerging as a major fuel for power generation, a similar rationalisation in the industry can be expected.

In Japan, the Gas Utility Industry Law amendment in 1995 now allows gas utilities to compete outside their service areas for customers contracting more than 2 million m^3/year [APERC, 2000b]. In one example, the Tokyo Electric Power Company (TEPCO), the largest electric utility in Japan is supplying gas to Ube Industries for an IPP project. TEPCO supplies this gas by way of the city gas company Ohtaki gas in the Chiba Prefecture. In the foreseeable future more electric utilities are expected to enter the gas supply business.

THE TRANS-EUROPEAN ENERGY NETWORK

HISTORY OF DEVELOPMENT

Natural gas was introduced in several European countries in the 1950s and 1960s following national exploration and development activities. Large-scale development was made possible only after signing of the first international contracts between two major producers, the Netherlands and Algeria, and the emergence of gas companies operating in Western Europe in the late 1960s. During the 1970s, Russia and then Norway began exporting natural gas to continental Western Europe.

Natural gas consumption in the 15 European Union member economies has increased from 60 Mtoe in 1970 to 302 Mtoe in 1997, an average increase of 6.2 percent per annum. In 1999, natural gas represented 22 percent of Europe's total primary energy consumption [Guillot, 1999].

The interconnected European gas network developed gradually, and is still undergoing development. To date, 175,000 km of transport pipelines have been laid to carry the growing import flows from fields located inside and outside Europe. In addition, 1.1 million kilometres of regional and local distribution lines are used to supply gas to 77 million end-users. A map of the interconnected European gas network is shown in Figure 1.

Towards the end of the 1950s, the first European gas transmission lines were built to transport gas from fields in the south-west of France, the north of Italy and the north of Germany to domestic markets. At this time there was no cross-border trade in natural gas in Europe.

The first international trade in natural gas began in the 1960s, with exports of gas from the Netherlands to Belgium, Germany and France, and the first imports of LNG from Algeria by the United Kingdom and France. The huge Groningen field in the Netherlands needed large markets to make development economical, and the long-term purchase contracts signed by gas companies in Germany, Belgium and France allowed the project to reach the economic threshold for development. A joint company named SEGEO was created between Distrigz and Gaz de France to own and operate the gas transmission line through Europe. The first cross-border European gas pipeline had been commissioned and others were soon to follow.

The next stage of development of the European interconnected gas network occurred in the 1970s with the development of huge new gas reserves in eastern Russia and in the British and Norwegian sectors of the North Sea. In both cases, buyer consortiums were formed between European gas companies in order to reach the economic threshold for upstream transport development, and also to mitigate the market risk for each member of the consortium. Joint subsidiaries were created between the European gas companies to own and operate the onshore network necessary for the transportation of Russian gas through Western Europe.

In the 1980s, Europe's main sources of supply were on stream and the main trend during this decade was the progressive shift from depleting local fields to the new gas reserves in Russia, Norway and Britain.

During this period, the first sub-sea link between the gas resources of Algeria and the markets in Europe was established, with the commissioning of the Transmed gas line between Algeria, Tunisia and Italy.

In the 1990s several major new pipelines were commissioned, increasing the security of gas supply in Europe. These included:

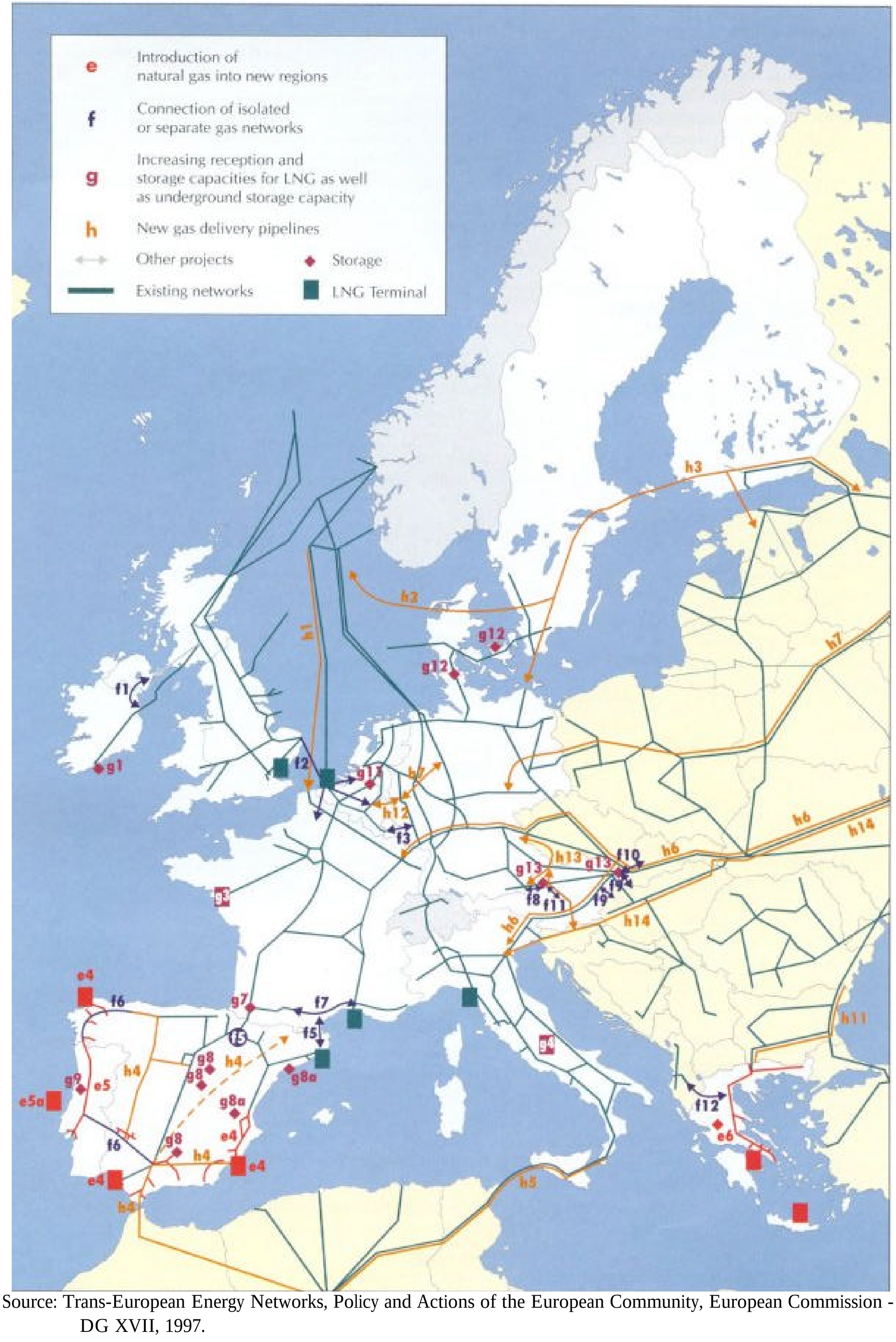
- The Maghreb-Europe gas pipeline, between Algeria, Morocco and Spain, the second gas pipeline linking Algeria and Europe;
- The interconnection between Portugal and Spain, and between Spain and France;
- The interconnection between Ireland and Great Britain and more recently, the Interconnector gas pipeline linking Great Britain and Continental Europe;
- The Norfra gas pipeline between Norway and France, the third link between the Norwegian North Sea and Europe.

The building of such a network required considerable investment, currently estimated to be approximately 10 billion Euros (around US$ 9.3 billion) yearly.

The development of natural gas markets in Europe reflects the wide-ranging national circumstances of each economy: some are self-sufficient in gas while others are fully dependent on imports from both EU and non-EU producers. The share of gas in primary energy consumption also varies drastically from country to country, from the total absence of a developed gas market to a maximum of 42 percent.

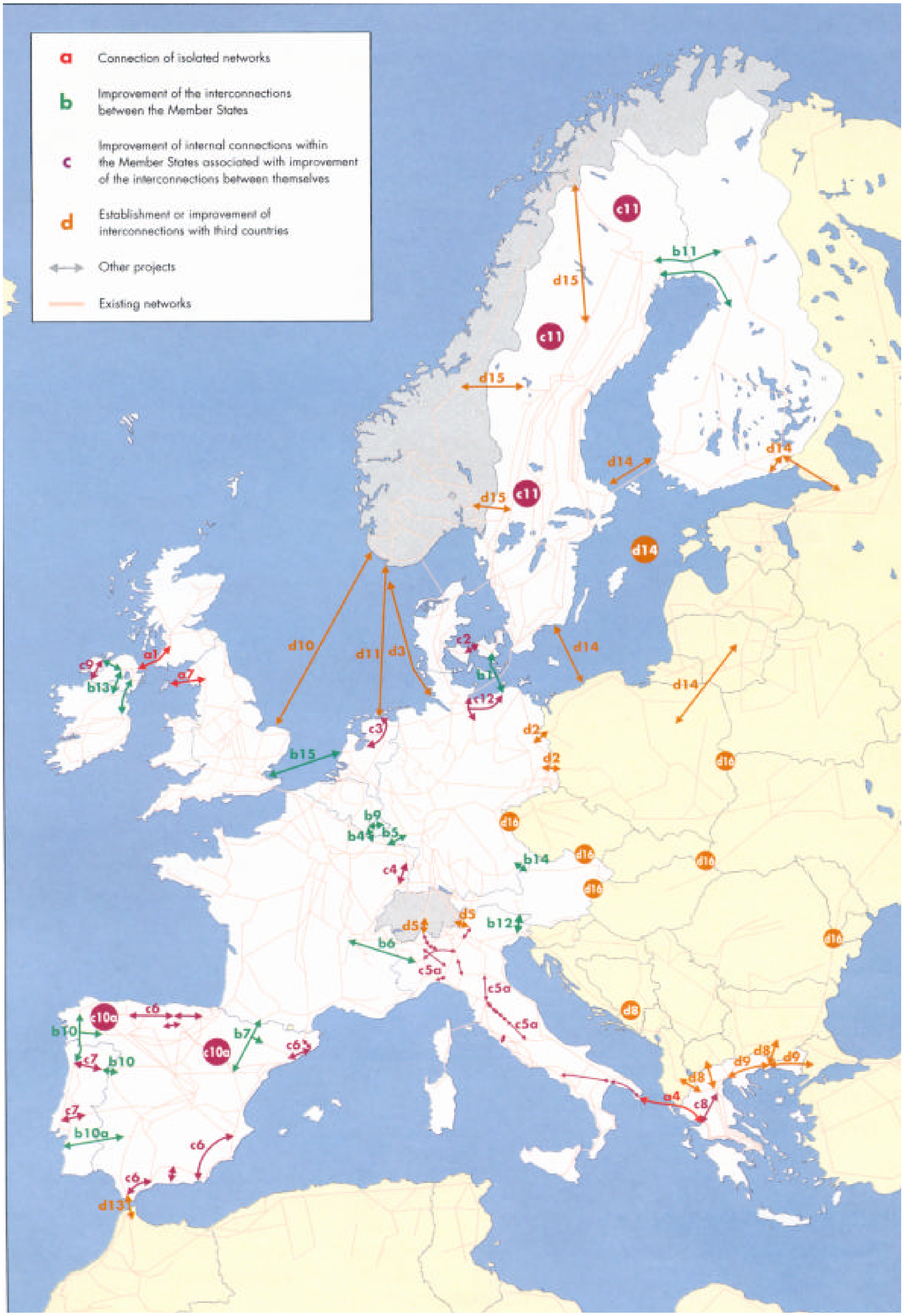
Despite the growing dependence of European gas markets on non-EU imports, gas supply has always been and remains highly reliable in Europe owing to long-term gas supply agreements, the exis-

Figure 1 Interconnected European gas network



Source: Trans-European Energy Networks, Policy and Actions of the European Community, European Commission - DG XVII, 1997.

Figure 2 The European electricity network



Source: Trans-European Energy Networks, Policy and Actions of the European Community, European Commission - DG XVII, 1997.

tence of the interconnected gas network with multiple sources of supply, and assistance agreements between gas companies in the case of gas supply chain disruptions.

FUTURE TRENDS

New gas links are being planned for the near future, such as a second gas pipeline between Russia and Western Europe through Poland, in order to cope with increased deliveries from Russia and to enhance the security of supply.

Europe is currently focusing not only on security of supply, but also on cost-efficiency through increased competition in the energy sector. This policy led to the recently adopted Gas Directive, which set phased targets for the opening of each member economy's gas market. Up to now, the cost-efficiency incentives for the European gas industry were provided by competition between gas and other fuels in downstream markets. The gas directive provides a new challenge for the gas industry, to continue developing the capacity and reliability of the European gas network within a new regulatory framework of wholesale gas-to-gas competition.

POWER GRID INTERCONNECTIONS

Historically, two separate European electricity grid systems existed, reflecting the major political divide between Western and Eastern Europe. The Union for the Co-ordination of Production and Transmission of Electricity (UCPTE) covers most of Western Europe. The grid systems in countries in the former Eastern bloc are often collectively referred to as Unified Power System (UPS) or Interconnected Power System (IPS). Within these blocs, a number of subdivisions

are often referred to, the most distinct being the CENTRAL Network (Czech Republic, Hungary, Poland and Slovak Republic) and the NORDEL (Nordic Electricity Grid) [Froggart, 1998].

Although both systems operate at the same nominal frequency (50 Hz), they are not synchronous. Furthermore the UPS system has been operated in the past over a wider frequency range than the UPCTE system, and thus the two grid systems have not been compatible.

Attempts are being made to make the major European power grids compatible, so that power can be traded in mainland Europe.

The European electricity networks are shown in Figure 2.

NORTH AMERICAN ENERGY INTEGRATION

NATURAL GAS

With growing cross-border trade in electricity, natural gas and oil, the three North American economies are becoming increasingly integrated in terms of energy supply [EIA, 2000].

Gas demand in North America is growing faster than the demand for other fuels, with the major market being power generation. By 2005, electric power generation may account for one-third of total US gas demand, compared to 24 percent in 1995.

Most of the gas cross border trade is between the Unites States and Canada. This is especially true of the Northeast United States and the Pacific Coast, where Canadian gas accounts for a significant share of gas supply.

Canadian gas exports to the United States have grown steadily over the last decade, bringing the Canadian share of the US gas market to 18 percent. The United States received 92,400 MMCM (3.3 Tcf) of natural gas from Canada in 1999, more than half of Canada's total natural gas production.

The opening of the Sable Island project in the northern Atlantic in late 1999 was a significant development marking the first commercial production of natural gas from a major Atlantic field off North America.

Virtually all Canadian gas (99 percent in 1997) is produced from the Western Canadian Sedimentary Basin (WCSB) which is located primarily in Alberta but extends into British Columbia, Saskatchewan and Manitoba [EIA, 1998].

Between 1998 and the end of 2000, three cross-border pipelines were expanded. These include:

- The Alliance pipeline which transports 36.4 MMCMD (1,300 Mmcfd) of gas from Western Canada to the Chicago area. The new pipeline project was completed in November 2000.

- The TransCanada and Foothills pipeline systems which bring 31.2 MMCMD (1,100 Mmcfd) of additional capacity to Chicago, which is set to become a major supply hub for imports of Canadian gas into the United States. The new pipeline project was completed in late 1998.

- The Maritimes and Northeast (M&N) pipeline, with a capacity of 12.6 MMCMD (445 Mmcfd), which brings gas from the Sable Island field off Nova Scotia to customers in northeastern United States. The expansion project was opened for use in December 1999.

A gas pipeline interconnection exists between the United States and Mexico, with smaller volumes traded in both directions. The United States exported 1,792 MMCM (64 Bcf) of natural gas to Mexico in 1999, while importing 1,540 MMCM (55 Bcf).

United States natural gas in Mexico is primarily to supply to manufacturing/service industries and a growing number of electric generating plants in the northern states of Mexico.

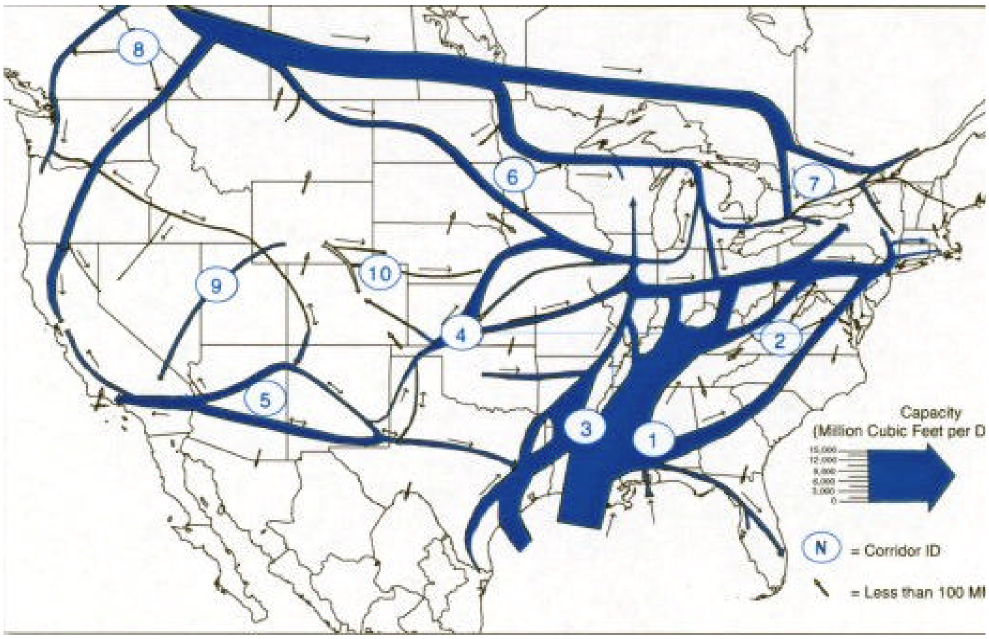
EXISTING INFRASTRUCTURE

In the United States, in 1996, according to the US Federal Energy Regulatory Commission (FERC), there were 89 interstate pipeline companies. The commission noted that 50 major pipeline companies owned close to 295,000 km of interstate lines and accounted for more than 96 percent of interstate transmission. There were 1,026 pipeline interconnections on these lines and 8,229 gas delivery points. There were also more than 65 major interstate pipeline companies in 1996 whose lines did not cross state boundaries [Gurney, 1998] (see Figure 3).

In Canada, the TransCanada pipeline, constructed in the 1950s, remains the main Canadian transcontinental line. It receives gas via interconnection with the Alberta Nova line on the Alberta border and with the smaller Saskatchewan TransGas line, and delivers the gas to domestic markets in Saskatchewan, Manitoba, Ontario and Quebec as well as to export markets in the US mid-west and northeast.

Other smaller Canadian pipelines that deliver gas domestically and to the United States include the

Figure 3 Major gas transportation corridors in the US and Canada



Source: Natural Gas 1999 Issues and Trends, Energy Information Administration, US-Department of Energy, April.

(1) Southwest - Southeast
(2) Southwest - Northeast
(3) Southwest - Midwest
(4) Southwest Panhandle - Midwest
(5) Southwest - Western
(6) Canada - Midwest
(7) Canada - Northeast
(8) Canada - Western
(9) Rocky Mountains - Western
(10) Rocky Mountains - Midwest.

following:

- The Nova NGTL system in Alberta which collects gas downstream of gas processing plants and transports it to markets within the province and, via interconnections with ANG/Foothills line and TransCanada, to markets in other provinces and in the US;

- Westcoast Energy, located in British Columbia, which extends into parts of northwest Alberta, the Yukon and the Northwest Territories, and interconnects with the US Northwest Pipeline for transport to markets primarily in the US Pacific northwest. It also interconnects in Alberta with Nova for deliveries to markets accessible from the latter's system;

- The ANG/Foothills line which connects the Nova system to Pacific Gas Transmission, a major export pipeline system which serves markets in northern California, the Pacific northwest and northwest Nevada, with the latter through an interconnection with Tuscarora Gas Transmission;

Market centres and improved storage access

Since 1990, 39 natural gas market centres have been established in the United States and Canada. They have become a key factor in the growing competitiveness within the natural gas transportation market, providing locations where many natural gas shippers and marketers can transact trades and receive value-added services. Among other features, they provide numerous interconnections and routes to enhance transfers and movements of gas from production areas to markets. In addition, many provide short-term gas loans to shippers who have insufficient (receipt) volumes to meet the contractual balancing requirements of the transporting pipeline. Conversely, temporary gas parking is often available when shippers find they are delivering too much gas to the pipeline. Market centres also offer transportation (wheeling) services, balancing, title transfer, gas trading, electronic trading, and administrative services needed to complete transactions on behalf of the parties.

Many of the services offered by market centres are supported by access to underground storage facilities. More than 229 underground sites (401 total) in the United States currently offer open-access services to shippers and others through market centres of interstate pipeline companies. These services are essential in today's transportation market - without them pipeline system operations would be much less flexible and seasonal demand would be more difficult to meet [EIA, 1998].

- Foothills Pipe Lines, owned by Westcoast and Nova, which connects the Nova line in Alberta to the Northern Border system in Saskatchewan, for export to the US mid-west. (This line was originally built as part of a project, which was never completed, to ship Alaskan North Slope gas to US regional markets.

In the United States, the natural gas industry has been undergoing large-scale regulatory changes, in large measure a result of Federal Energy Regulatory Commission (FERC) Order 636 (1992) which “unbundled” the purchase of gas from its transport. This rule requires pipeline operators to separate their sales services from their transportation services. The rule issues blanket sales certificates to the pipeline operators so they can offer unbundled firm and interruptible sales services at market-based prices. “Unbundled” transportation services and storage services ensure improvement in quality of such services. The retail unbundling has also given rise to the development of more market centres with improved storage, which became necessary with growing competition in the gas transportation market (see box below).

ELECTRICITY

An overview of existing power interconnections in North America was covered at some length in 2000 APERC report: Power Interconnection in the APEC Region [APERC, 2000a]. Readers are advised to refer to Chapter 5 of that report for details about the history of cross-border trade in electricity in North America. A brief summary is provided in the box below.

The first cross-border trade in power in North America began operation in 1901, connecting a 90 MW hydroelectric power plant on the Canadian side of the Niagara Falls to Buffalo, New York, some 30 km away. In 1905, the United States and Mexico were interconnected, serving the requirements of border communities.

More cross-border lines were installed over the next century. As of 1998, there were 79 transmission lines between the United States and Canada and 27 between the United States and Mexico. It must be noted however, that most operate at voltage levels that correspond to subtransmission or distribution lines.

Despite the high absolute value of power flowing in both directions across the US-Canada and US-Mexico borders, net exports and imports are low. The United States has been a net-importer of electricity from both Canada and Mexico.

Less than 2 percent of the current US electricity demand is supplied by net imports through cross-border interconnections, and they are almost all from Canada. On a net basis the amount imported in 1997 was 32.2 billion kWh, representing only 1.4 percent of total US electric energy requirements for that year.

In terms of exports from the United States, 90 percent went to Canada and the remaining 10 percent to Mexico.

While Canada and the United States have a fairly well developed network of interconnections that may meet future requirements, the situation between Mexico and the United States allows for significant improvements. One current interconnection project (due to be completed in 2002) is the Palo Verde Interconnection, consisting of two transmission lines capable of carrying 800 to 1,000 MW.

LNG INFRASTRUCTURE IN THE ASIA PACIFIC REGION

On supply side LNG plant construction requires investment in site preparation, harbour, marine, tankage, accommodation, gas processing utilities and the general infrastructure. On the demand side LNG requires large investments by the buyers in terminal and re-gasification facilities. So LNG infrastructure generates a significantly higher gas price in Japan, Korea and Chinese Taipei than it is in Europe and United States (actual numbers in 2000). The Asia Pacific Region dominates LNG trade with more than three-quarters of total supply. LNG trade expanded significantly after the first oil shock in 1973-74. In 1970s Japan started imports from Alaska, US, Brunei, Indonesia and Abu Dhabi with long-term take-or-pay contracts. Malaysia started LNG shipments in 1983 and Australia in 1989. Korea began to take LNG in 1986 and Chinese Taipei in 1990 from Indonesian plants, mainly fueling growing power generation demand.

Table 2 and Table 3 represents an LNG demand outlook for the region and operating LNG units serving the Northeast Asian market.

Currently there is some 10 Mt overcapacity in LNG supply for Northeast Asia. Thus, in the year 2000, Arun LNG plant in Aceh, Indonesia with 6-train 12 Mt/year capacity has been urged to stop operation of 2 trains due to the decrease in demand for LNG in Japan. However, new capacity will be need-

Table 2 LNG demand outlook for Northeast Asia

	1999 (Actual) (Million tonnes)	2010 (Million tonnes)	*AAGR (%)
Japan	51.3	64.0	2.0
Korea	12.97	22.0	4.9
Chinese Taipei	4.16	11.0	9.2
Subtotal	68.43	97.0	3.2
India	0	5.0—10.0	--
China	0	3.0—5.0	--
Total	68.43	105.0—112.0	4.0—4.6

Source: The Institute of Energy Economics, Japan (2000)
*Average annual growth rate

ed to meet LNG demand in 2010 projected at the level 100-103 Mt. Taking into account the scale of economic viability for a new LNG production facility to be 6 Mt/year or more, that means construction of additional 3 LNG plants.

The competition between potential LNG supply projects in Asia Pacific will be sharp. Table 4 lists proposed new LNG production capacities targeted on the Northeast Asian market.

Securing LNG demand for actively developing Sakhalin-1 and Sakhalin-2 projects seems to be problematic before the year 2010. Currently these two projects are moving towards a decision to construct a joint pipeline infrastructure linking hydrocarbon fields in Northern Sakhalin off-shore with proposed 8.9 Mt LNG production plant in Southern Sakhalin.

Similar problems with potential buyers exist for the new LNG capacity building proposals in Australia, Indonesia and Papua New Guinea. Steadily increasing gas demand in the second decade of the 21st century will create development opportunities for these fields.

Table 3 Existing LNG projects in the Asia Pacific region

Economy	Terminal	Train	Volume (Million tonnes)	Start-up
USA (Alaska)	Kenai	1	1.3	1969
Brunei	Lumut	5	6.6	1972
Indonesia	Bontang A,B	2	5.2	1977
	Bontang C,D	2	5.2	1983
	Bontang E	1	2.6	1989
	Bontang F	1	2.6	1993
	Bontang G	1	2.7	1997
	Bontang H	1	2.7	1999
	Arun 1	3	6	1978
	Arun 2	2	4	1983, 1984
	Arun 3	1	2	1986
Malaysia	MLNG	3	8.1	1983
	MLNG	3	7.8	1995, 1996
Australia	Karratha	3	7.5	1989
Abu Dhabi	Das Island 1	2	2.5	1977
	Das Island 2	1	3	1994
Qatar	Qatargas	3	6	1997, 1998
	Ras Laffan	1	2.5	1999
Total		36	78.3	

Source: The Institute of Energy Economics, Japan (2000)

Table 4 LNG projects for Asian markets

	Volume (Million tonnes)	Start-up target
In operation		
Asia Pacific	64.3	Re: Table-2
Middle East	14.0	
Subtotal	78.3	
Under construction or Contract signed		
Oman	6.6	2000
RasGas (Qatar)	10.0	
Malaysia Tiga	6.8	2003
Subtotal	23.4	
In progress toward contract (reportedly)		
Australia NWS expansion	7.0	
Under consideration		
Yemen	5.3	2003
Gorgon (West Australia offshore)	6.0	2005
Tangguh (Indonesia)	6.0	
Bayu/Undan (Australia./Indonesia)	3.0	2003
Sakhalin 2 (Russia)	8	2005
Darwin (Australia)	7.5	
Iran	4.3	
North Slope (Alaska USA)	14	2007
Scarsborough (Australia)	5	
Natuna (Indonesia)	15	2007
Papua New Guinea	4	2005
Subtotal	78.1	
Total	186.8	

Source: The Institute of Energy Economics, Japan (2000)

CHAPTER 3

ENERGY DEMAND AND SUPPLY IN ASIA

INTRODUCTION

Despite the recent financial crisis in Asia, the demand for all forms of energy is expected to recover to pre-crisis rates of growth in the near future, and it is expected this growth will be sustained over the next two decades [APERC, 1998].

FUTURE OUTLOOK

The projected electricity demand growth under the B98 and PCS scenarios of the APERC Outlook are 3.2 percent per annum and 2.9 percent per annum between 1995 and 2010 respectively. This would suggest that total demand will grow by over 60 percent over this period under a business as usual scenario.

China and the US are the major contributors to total electricity demand growth in the APEC region. Following these two are Japan, Korea and Chinese Taipei.

The APERC Outlook also suggests that China and Southeast Asia (which includes Brunei Darussalam, Indonesia, Malaysia, the Philippines, Singapore and Thailand) will experience higher electricity supply growth rates than other APEC sub-regions.

Table 5 Electricity demand forecast by region, Baseline '98 (B98) scenario

	1995	2000		2010		Growth (1996-2010)	
	(Actual)	B98	PCS	B98	PCS	B98	PCS
			mtoe			percent	
APEC	521.4	609	597.6	835.9	795.1	3.2	2.9
USA	269.2	297.4	295.3	347.5	340.5	1.7	1.6
Other Americas	52	57.7	56	80.3	74.5	2.9	2.4
China	67.3	100.3	97.1	179.4	167.5	6.8	6.3
Other East Asia	99.5	112.8	110	158.6	148.1	3.2	2.7
Oceania	15.5	18.4	18.3	26.8	26.3	3.7	3.6
Southeast Asia	17.9	22.2	20.9	43.2	38.2	6	5.2

Source: APERC, 1998.

The APERC Outlook indicates that the total electricity generation capacity of the APEC member economies will increase from 1,545 GW in 1995 to 2,381 in 2010 in a business as usual scenario. This implies that 836 GW of incremental capacity will be required over the forecast period.

Although Southeast Asia is expected to make a relatively small contribution to the overall growth in capacity, the growth rate in this region will be high, at around 5.4 percent per annum.

East Asia and Southeast Asia will account for 70 percent of the required power generation capacity addition. Better planning and cooperation in the electricity sector - including consideration of viable interconnections - could optimise capacity expansion requirements.

FUEL CONSUMPTION

With assumptions regarding improvements in efficiency, total electricity generation fuel demand in the APEC region is expected to grow by around 2.8 percent to 2010, a total increase of around 50.4 percent from 1995 to 2010. These growth rates are higher than growth in total primary energy supply. Table 6 shows forecasts for electricity generation fuel consumption.

Table 6 APEC electricity generation fuel consumption forecast

	1995	2000		2010		Growth (1996 – 2010)	
	(Actual)	B98	PCS	B98	PCS	B98	PCS
			Mtoe			percent	
Total APEC	1610.7	1861	1824.8	2422	2307.8	2.8	2.4
Oil	128.9	133.2	124.8	136.2	121.1	0.4	-0.4
Gas	222.0	260.9	255.8	440.9	417.7	4.7	4.3
Coal	801.1	955.1	936.5	1239.7	1183.1	3.0	2.6
Geothermal	29.4	53.8	52.6	60.4	57.1	4.9	4.5
Hydropower	90.0	101.1	99.8	126.5	122.0	2.3	2.0
Nuclear	310.3	322.9	321.9	373.6	362.5	1.2	1.0
Other	29.0	34.4	33.4	44.7	44.3	2.9	2.9

Source: APERC, 1998.

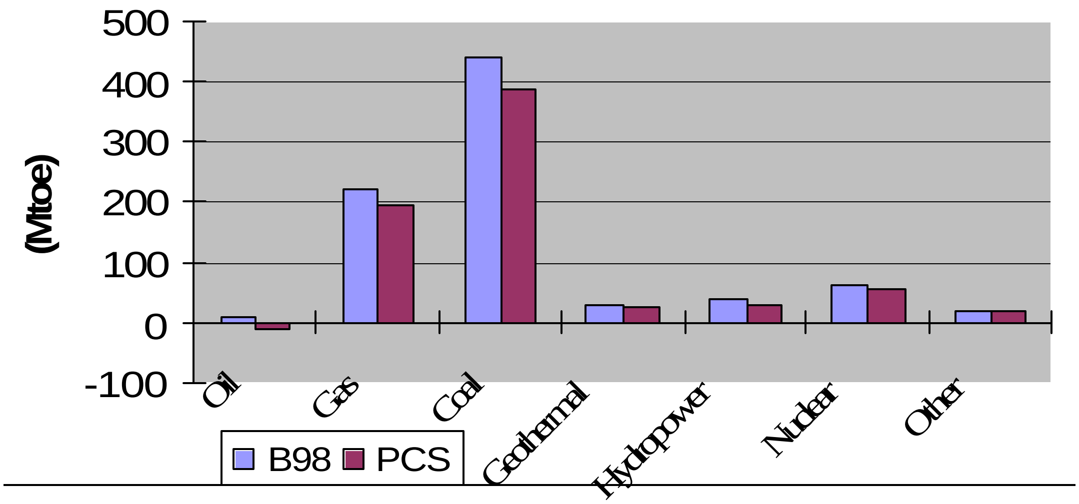
By fuel type, the demand for fossil energy (oil, natural gas and coal) for power generation is expected to grow around 3.1 percent over the forecast period. The share of fossil energy in the fuel mix is expected to actually increase over the forecast period, from 71.5 percent in 1995 to 75 percent.

Figure 4 shows projected fuel demand for power generation.

Among the major fuels, coal is expected to remain the dominant energy source for power generation. Coal will comprise around 51 percent of total power generation fuel requirements in 2010, up from around 50 percent in 1995.

Behind coal, natural gas will make the next most important contribution to power generation fuel demand growth, and is expected to comprise over 18 percent of total power generation fuel requirements in 2010. Total gas demand for electricity generation is expected to increase by almost 99 percent over the period 1995 - 2010.

Figure 4 Projected fuel demand for power generation in 2010



Source: APERC, 1998.

The economies in Asia, as they recover from the financial crisis, will start to grow rapidly again. For example, Indonesia, an APEC economy badly hit by the financial crisis experienced 5.1 percent growth in the third quarter of 2000 [Indonesian Observer, 2000]. During the same period, in Northeast Asia, China and Korea recorded GDP growths of 8.2 and 9.2 percent, respectively. In Southeast Asia, Malaysia and the Philippines recorded growth of 7.7 and 4.8 percent, respectively. Singapore, the Southeast Asian nation least affected by the crisis, continued to experience double-digit growth of 10.4 percent [Far East Economic Review, 2001].

Table 7 shows natural gas and electricity energy demand for Northeast Asia (China, Korea and Japan) and Southeast Asia (Brunei Darussalam, Indonesia, Malaysia, the Philippines, Singapore and Thailand), based on the 1998 APERC business-as-usual scenario [APERC, 1998]. These projections suggest that natural gas demand in both Northeast and Southeast Asia will grow by an annual average of over 5 percent, whereas electricity demand will be slower in Northeast Asia (3.3 percent per year) than in Southeast Asia (5.2 percent per year).

Eastern Russia is well endowed with natural gas and hydropower resources whereas neighbouring

Table 7 Natural gas and electricity demand projected to 2010

	Natural Gas Demand (2000 – 2010)		Electricity Demand (2000 – 2010)	
	Demand in 2010	Annual growth	Demand in 2010	Annual Growth
Northeast Asia	193.9 Mtoe (215.4 BCM)	5.90%	527.4 Mtoe	3.30%
Southeast Asia	112.6 Mtoe (125.1 BCM)	5.40%	80.3 Mtoe	5.20%

Source: APERC, 1998.

economies such as China, the Republic of Korea and Japan are major markets. Cross-border infrastructure in the form of natural gas pipelines and power grids are practical means of transporting these energy commodities to demand centres.

In Southeast Asia, natural gas exporters such as Indonesia, Malaysia and Myanmar can export natural gas economically to nearby neighbours, such as Thailand and Singapore, through pipeline interconnections. Economies such as Viet Nam and Laos PDR within the Mekong Basin have ample hydropower potential, and are able to export electricity economically to Thailand.

APERC reports published in March 2000, [APERC, 2000a; APERC, 2000b; APERC, 2000c] looked at the availability of natural gas and electricity energy sources in Northeast and Southeast Asia and the potential markets within the region. Further discussion of these infrastructure plans and options, as well as some economic analysis, are discussed in Chapters 5 and 6.

ENVIRONMENTAL IMPLICATION

Demand for electricity in Asia is expected to grow rapidly in the coming years. Carbon dioxide emissions produced during the generation process, particularly when using fossil fuels, are also expected to increase.

As discussed above, fuel consumption for power generation in APEC region in all cases encompassing B98, EFS and PCS will increase both its volume and share in the region's total primary energy supply (TPES). Pollutant emissions from power generation will increase accordingly (see Figure 5). This also implies that other forms of pollutants like SO_2, NO_x and particulates or dusts emitted from electricity generation will be likely to increase if proper measures are not taken. Thus, mitigating these environmental impacts becomes a key task facing the sector.

Therefore, it is clear that APEC member economies especially those in Asia will need to consider all possible options including power grid interconnection, which tend to introduce fuels with less carbon content and other hazardous components to the environment, to meet their electricity demand in the future.

CURRENT NATURAL GAS CONSUMPTION TRENDS

POWER SECTOR

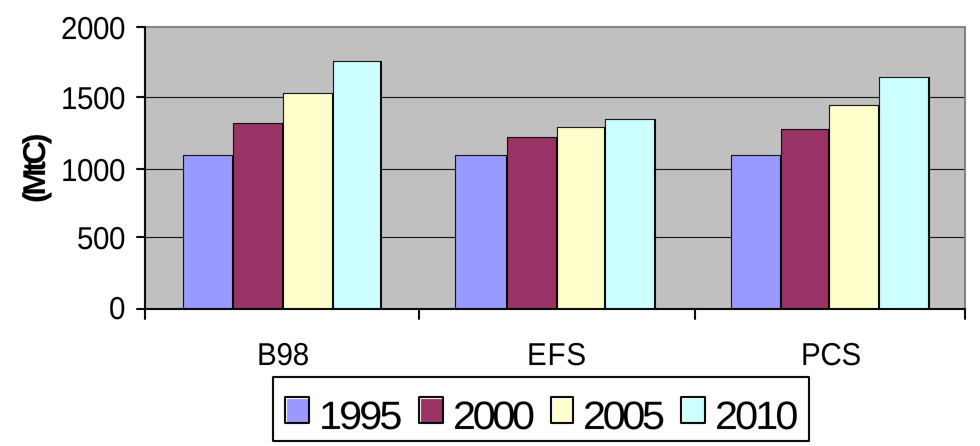
NORTHEAST ASIA

Table 8 shows the fuel input share for the power sector in Northeast Asia.

In China, natural gas comprises only 0.7 percent (1,788 ktoe) of total fuel input for electricity generation. Coal is the dominant power generation fuel, (84.7 percent - 231,154 ktoe), followed by hydropower (6.6 percent - 17,894 ktoe) and petroleum products (5.3 percent - 14,676 ktoe).

Although current natural gas consumption for power generation is negligible, this fuel has a promising future if gas can be made available at competitive prices to the eastern and southern regions where the large demand centres are. CCGT plant investment costs are about half those of flue gas desulphurised (FGD) coal power plants (about US$ 600/kW against about US$ 1,200/kW).

Figure 5 CO_2 emissions from electricity generation (1995 - 2010)



Source: APERC, 1998.

Japan maintains a diversified power generation fuel-mix, partly for security of supply reasons. The most important fuels are nuclear (44.5 percent - 84,949 ktoe), natural gas (21.7 percent - 41,299 ktoe) and coal (16.5 percent - 31,392 ktoe). Other fuels represent less than 6 percent of the total. With reduction of carbon emissions a priority, and nuclear expansion unpopular, natural gas is in a strong position to dominate future power generation investments. Japan has fully utilised its available large-scale hydro resources.

Korea also has an active nuclear power development policy. In 1998, nuclear comprised 47.5 percent of total net generation. The share of natural gas is still small at 10 percent (4,902 ktoe).

Table 8 Fuel input for power generation in Northeast Asia (for 1998)

	Natural gas	Petroleum products	Coal	Hydro	Renew-ables	Nuclear	Other	Total
				ktoe				
China	1,788	14,676	231,154	17,894		3,674	3,880	273,066
	(0.7%)	(5.3%)	(84.7%)	(6.6%)		(1.3%)	(1.4%)	(100%)
Japan	41,299	13,065	31,392	8,118	3,092	84,949	8,814	190,729
	(21.7%)	(6.8%)	(16.5%)	(4.3%)	(1.6%)	(44.5%)	(4.6%)	(100%)
Korea	4,902	3,459	16,994	525		23,373		49,253
	(10.0%)	(7.0%)	(34.5%)	(1.0%)		(47.5%)		(100%)
Russia	182,507	31,680	31,660	13,674	26	26,973		286,520
	(63.7%)	(11.1%)	(11.0%)	(4.8%)	(0.0%)	(9.4%)		(100%)
NE Asia Total	230,496	62,880	311,200	40,211	3,118	138,969	12,694	799,568
	-28.80%	(7.9%)	(38.9%)	(5.0%)	(0.4%)	(17.4%)	(1.6%)	(100%)

Source: EDMC, 2000
Renewables includes geothermal, wind, solar, and biomass.

Russia on the other hand, relies heavily on natural gas for the power sector, with gas-fired generation accounting for 63.7 percent of the total in 1998 (182,507 ktoe). Other fuels include fuel-oil (11.1 percent - 31.680 ktoe), coal (11.0 percent - 31,660 ktoe), and nuclear (9.4 percent - 26,973 ktoe). Hydropower comprises 4.4 percent of total net generation (13,674 ktoe). Russia has the world's largest proven reserves of natural gas (1.35 TCM in January 2000) [BP Amoco, 2000]. Russia also has large-scale hydropower resources. The economic potential of hydropower is estimated at 852 TWh/year, nearly 20 percent of which is already developed [APERC, 2000d].

Natural gas would, from an environmental perspective, be a sensible power generation choice for China, Japan and Korea in meeting energy supply needs. These economies can also import electricity directly via transmission grid. But any electricity wheeled from a distant source of generation, irrespective of whether it is hydropower or gas-fired will have to be purchased at a premium price that also include generation costs, transmission costs and the externality costs at the generating end. Electricity importing economies, however, will usually use local electricity costs as its benchmark price. Although it may not always be so, it is likely that the price of imported electricity would be higher than the domestic price, especially if electricity is the energy form required. Economics is the single most important criteria for deciding whether to import natural gas and generate the electricity locally or to import electricity in its final form.

In fact, Russia is the nearest source of natural gas and electricity for China, Korea and Japan. These proposed interconnections were analysed in APERC previous study reports [APERC, 2000a and APERC, 2000b]. Some of the possible routes and the latest development are highlighted in Chapter 5.

SOUTHEAST ASIA

Table 9 shows the fuel input share for the power sector in Southeast Asia.

Brunei Darussalam, with reserves of 0.39 TCM in January 2000 (BP-Amoco) is one of Southeast Asia's major exporters of natural gas. Since 1981, the electricity sector has been almost 100 percent gas-fired, except for a small amount of diesel use [AEEMTRC, 1993]. With a currently installed capacity of 750 MW, and peak load of 379 MW, Brunei is unlikely to require additional capacity for some years [APERC, 2000c].[2]

Indonesia has a diversified power generation fuel-mix with a fairly high percentage of natural gas currently (32.2 percent - 6,702 ktoe), up from 4.0 percent (126 ktoe) in 1991. The share of coal-fired power generation has declined over this time period - from 38 percent in 1991 to 29.3 percent in 1998. In real terms, coal consumption has increased from 1,200 ktoe to 6,105 ktoe over the 8-year period, as overall demand for electricity has grown significantly. If Indonesia continues to place a priority on environmental policies, consumption of natural gas to meet local power demand should continue to grow quickly.

Malaysia also relies heavily on natural gas for power generation. The share of gas-fired generation is currently 69.8 percent (9,158 ktoe), a large increase from less than 2 percent in 1981. With such a high dependance on natural gas in the power sector, fuel diversification policies will promote other options in the near future. These options include coal and renewables such as palm oil wastes.

The Philippines is the only economy in this region with almost no natural gas-fired generation. However, the Comago-Malampaya pipeline project when completed in 2002 is expected to change this situation. The flow is expected to be 3.33 BCM (2,997 ktoe) in 2004 [APERC, 2000c], at which time the share of natural gas is expected to reach 17.0 percent (2,736 MW out of 16,089 MW) [Philippines DOE, 1999].[3]

Table 9 Fuel input for power generation for Southeast Asia (for 1998)

	Natural Gas	Petroleum Products	Coal	Hydro	Renew-ables	Other	Total
				ktoe			
Brunei	1,462	5	0	0	0	0	1,467
	(99.7%)	(0.3%)	(0.0%)	(0.0%)	(0.0%)	(0.0%)	(100%)
Indonesia	6,702	3,800	6,105	908	3,309	0	20,824
	(32.2%)	(18.2%)	(29.3%	(4.4%)	(15.9%)	(0.0%)	(100%)
Malaysia	9,158	2,584	964	417	0	0	13,123
	(69.8%)	(19.7%)	(7.3%)	(3.2%)	(0.0%)	(0.0%)	(100%)
Philippines	8	4,157	1,709	436	7,666	1,893	15,869
	(0.1%)	(26.2%)	(10.8%)	(2.7%)	(48.3%	(11.9%)	(100%)
Singapore	1,132	4,535	0	0	0	64	5,731
	(19.8%)	(79.1%)	(0.0%)	(0.0%)	(0.0%)	(1.1%)	(100%)
Thailand	11,373	4,299	4,026	445	2	0	20,145
	(56.5%)	(21.3%)	(20%)	(2.2%)	(0.0%)	(0.0%)	(100%)
Viet Nam	736	1,000	1,363	954	0	0	4,053
	(18.2%)	(24.7%)	(33.6%)	(23.5%)	(0.0%)	(0.0%)	(100%)
Total ASEAN	30,571	20,380	14,167	3,160	10,977	1,957	81,212
	(37.6%)	(25.1%)	(17.4%)	(3.9%)	(13.5%)	(2.4%)	(100%)

Source: APEC Energy Database, EDMC
Renewables includes geothermal, wind, solar, and biomass.

The power sector in Singapore has been traditionally highly dependent on fuel oil - currently 79.1 percent (4,535 ktoe) of the total fuel share. This explains why Singapore is rigorously pursuing the import of natural gas, tripling import quantities from the Malaysian PGU pipelines completed in 1992. With the recent completion of the pipeline from the West Natuna an additional 9.1 MMCMD will be imported [Jakarta Post, 2001]. With the national power grid interconnected to Peninsular Malaysia, Singapore could also benefit from power imports, if a commercially attractive electricity price could be negotiated. As Malaysia currently has a large reserve margin, trade in electricity could be beneficial to both economies.

Thailand is the only gas importing economy in Asia with a high percentage of natural gas-fired power generation. Natural gas currently comprises 56.5 percent (11,373 ktoe), of the total fuel mix, reflecting Thailand's seriousness in reducing an historical dependence on oil and coal for power generation, and a desire to reduce the emissions from these fuel types. For over 20 years, Thailand had been self-reliant with respect to the use of natural gas. Since late 1999, Thailand has been importing gas from Myanmar, through a pipeline from the Yadanna gas-field to the Ratchaburi power plant. Thailand will receive an additional 390 MMscfd of gas when the 34-inch pipeline from the Malaysia-Thailand Joint Development Area is completed in mid-2002 [DMR, 1999]. Thailand also has plans to import electricity from Laos and Viet Nam. More information about the interconnection activities in the Mekong Basin are provided in Chapter 6.

Viet Nam is another natural gas producing economy in Southeast Asia, but so far all production has focused on domestic consumption. No export plans have been developed for the near future. The share of natural gas in Viet Nam's power generation fuel-mix is 18.2 percent (736 ktoe), and the government is planning to increase this share. Viet Nam also has substantial hydropower resources, with a gross theoretical potential of 300 TWh/year, and a technically feasible potential of 90 TWh/year [APERC, 2000a]. As of 1996, only 12 TWh/year (13.3 percent) has been exploited [AEEMTRC, 1998].

NON-POWER SECTOR

NORTHEAST ASIA

Table 10 shows the use of natural gas in different sectors in Northeast Asia.

At 22,442 ktoe, the total consumption of natural gas in China is small. This represented merely 4.0 percent of China's total final energy consumption for 1998, (563,147 ktoe) [APERC, 2000]. Most of the gas is used in the industrial sector (15,594 ktoe or 69.5 percent) and the residential sector (5,038 ktoe or 22.5 percent). Little gas is currently used for power generation (1,788 ktoe or 8.0 percent of total gas consumption).

With a total consumption at 61,743 ktoe, natural gas made up 17.8 percent of Japan's total final energy consumption in 1998 (346,908 ktoe). The power sector consumed 41,299 ktoe (66.9 percent), the res-

Table 10 Natural gas consumption by sector in Northeast Asia (for 1998)

Economy	Electricity	Industry	Residential/ Commercial	Transport	Non-Energy	Total
			ktoe			
China	1,788	15,594	5,038	22	0	22,442
	(7.97%)	(69.49%)	(22.45%)	(0.10%)	(0.00%)	(100%)
Japan	41,299	7,587	12,857	0	0	61,743
	(66.89%)	(12.29%)	(20.82%)	(0.00%)	(0.00%)	(100%)
Republic of Korea	4,902	1,630	6,728	0	0	13,260
	(36.97%)	(12.29%)	(50.74%)	(0.00%)	(0.00%)	(100%)
Russia	182,507	127,038*	0	0	11,271	320,816
	(56.89%)	(39.60%)	(0.00%)	(0.00%)	(3.51%)	(100%)
Hong Kong	2,013	19	495	0	0	2,527
	(79.66%)	(0.75%)	(19.59%)	(0.00%)	(0.00%)	(100%)
Chinese Taipei	6	887	740	0	0	1,633
	(0.37%)	(54.31%)	45.32%))	(0.00%)	(0.00%)	(100%)
TOTAL	235,390	152,755	25,858	22	11,271	425,296
	(55.35%)	(35.92%)	(6.08%)	(0.01%)	(2.65%)	(100%)

Source: EDMC, 2000
* For Russia - data for industry are total final energy consumption.

idential and commercial sectors 12,857 ktoe (20.82 percent) and the industrial sector 7,587 ktoe (12.3 percent).

Total natural gas consumption in Korea in 1998 was 13,260 ktoe. This represented 10.6 percent of Korea's total final energy consumption (which totalled 124,563 ktoe). The residential and commercial sectors are the major consumers (6,728 ktoe or 50.7 percent), followed by the power sector (4,902 ktoe or 37.0 percent) and the industrial sector (1,630 ktoe or 12.3 percent). Korea has plans to increase the imports of gas, for both power and non-power sectors.

China, Japan and Korea all plan to increase the consumption of gas in the electricity and non-electricity sectors. These economies will meet these requirements through importation of LNG, and in the case of China, pipelines tapping domestic gas fields. Any vision of long-distance pipelines supplying these markets would need to focus on the gradual development of an interconnected network, with each leg justified financially on the basis of meeting demand in relatively nearby markets. Another option for these three economies, will be meeting some of their power supply requirements through importation of electricity. This is discussed further in Chapter 5.

SOUTHEAST ASIA

Table 11 shows the natural gas use across all sectors in Southeast Asia.

As discussed earlier, Brunei Darussalam, Russia and Malaysia use significant shares of natural gas for power generation (98 percent, 70.1 percent and 63.7 percent of the power generation fuel mix, respectively). These are natural-gas exporting economies, with gas reserves and production sufficient to sustain export commitments as well as meet increasing domestic demand. Greater utilisation of natural gas in these economies can be achieved through extension of local distribution networks to facilitate gas use in sectors other than the power sector.

Malaysia is a good example of a gas producing economy with a well-developed local gas pipeline distribution infrastructure. The Peninsular Gas Utilisation (PGU) pipelines comprise a network spanning 1688 km (including loops).[4] This network carries 56 MMCMD, and has an additional standby capacity of 21 MMCMD. Its southern leg stretches from the east of the Peninsula to the southern border with Singapore (supplying 4.2 MMCMD of gas to Singapore) making this short span the first trans-border gas pipeline in Southeast Asia. The northern leg passes through Kuala Lumpur and the Klang Valley area (where the demand is highest) and extends further north to the southern border of Thailand. The major consumers of gas are the power plants, with a small percentage used as feedstock for petrochemical plants, and a smaller amount used in the commercial and residential sectors. A small amount is used in the transportation sector for natural-gas vehicles (NGV).

Gas-fired power generation in Brunei Darussalam, Malaysia and Indonesia is well developed, and future strategies will encourage greater use of natural gas in non-electricity sectors.

Singapore is becoming an increasingly attractive market for natural gas. For many years Singapore has used "town gas," produced domestically from naphtha, in the industrial, residential and commercial sectors. Singapore started importing natural gas from the Malaysian Peninsular Gas Utilisation network 1992, and now imports 1,132 ktoe through this source. This comprised 32.2 percent of Singapore's total final energy consumption in 1998. With the recent completion of the Singapore-Indonesia pipeline, gas imports are expected to rise substantially, and there are further plans to import natural gas by pipeline from Sumatra.

Thailand, according to Table 11, utilised 12,255 ktoe of natural gas in 1998. This represented 31.4 percent of Thailand's total final energy consumption in 1998 [APERC, 2000d]. Of the total gas con-

Table 11 Natural gas consumption by sector in Southeast Asia (for 1998)

Economy	Electricity	Industry	Residential/ Commercial	Transport	Non-Energy	Total
			ktoe			
Brunei Darussalam	1,624	0	24	0	0	1,648
	(98.54%)	(0.0%)	(1.46%)	(0.00%)	(0.00%)	(100%)
Indonesia	6,702	4,311	8	23	2,990	14,034
	(47.76%)	(30.72%)	(0.06%)	(0.16%)	(21.31%)	(100%)
Malaysia	9,158	1,420	10	4	1,282	11,874
	(77.13%)	(11.96%)	(0.08%)	(0.03%)	(10.8%)	(100%)
Philippines	8	0	0	0	0	8
	(100%)	(0.0%)	(0.00%)	(0.00%)	(0.00%)	(100%)
Singapore	1,132	0	0	0	0	1,132
	(100%)	(0%.0)	(0.00%)	(0.00%)	(0.00%)	(100%)
Thailand	11,373	877	0	5	0	12,255
	(92.8%)	(7.16%)	(0.00%)	(0.04%)	(0.00%)	(100%)
Viet Nam	736	0	0	0	0	736
	(100%)	(0.00%)	(0.00%)	(0.00%)	(0.00%)	(100%)
TOTAL	30,733	6,608	42	32	4,272	41,687
	(73.72%)	(15.85%)	(0.10%)	(0.08%)	(10.25%)	(100%)

Source: EDMC, 2000

sumption in 1998, 92.8 percent was consumed in the power sector and only 7.2 percent was consumed in the industrial sector, mainly as feedstock for the petrochemical industry. The transport sector consumes a small amount, around 0.1 percent.

Natural gas provides a mere 3.2 percent of Viet Nam's total final energy consumption. The natural gas industry in Viet Nam is relatively new, and a small percentage is being used by the non-power sectors. A major constraint currently is the lack of a well-developed gas distribution network.

ENERGY POLICIES IN THE APEC REGION

The energy policies of APEC economies generally place priority on energy security, as well as environmentally sound development and utilisation of energy. Although historically environmental policy has focused on pollutant emissions and health impacts, increasingly the mitigation of greenhouse gas emissions is becoming an important policy consideration, even in economies that are not formal signatories of the Kyoto Protocol. Wider use of natural gas, the most environmentally benign fossil fuel in both electricity and non-electricity sectors, is being given high priority in the energy development policies of these economies.

Consequently, the planning and development of large-scale energy infrastructure projects in the form of natural gas and power grids, although they are capital intensive, are essential priorities in economic and energy planning. Such planning depends on a multitude of issues, including: availability of indigenous energy resources, economic and energy growth forecasts, general state of industrial development, energy supply security, and environmental strategies.

ENERGY SUPPLY SECURITY

Energy supply security is an important consideration in the energy policy decision-making process in Asia, and is a significant issue with respect to cross-border trade in energy.

For example, a regional gas pipeline could become an important tool in maintaining and bolstering energy security in Asia, as has been the case in Europe. System security is provided by the physical capacity of the transmission line, which acts as a buffer against short-term supply disruptions, and by multiple suppliers (preferably from a number of different economies) feeding gas into the network.

Of course, there can be threats to energy security with such an interconnected system, such as a terrorist attack on the transmission line, or rogue states refusing to maintain supplies for political reasons. However, as has been experienced with respect to the interconnected European gas network, the benefits of such infrastructure greatly outweigh the risks, and the net effect is a reduction in dependency on Middle East oil, a source of energy supply that is easily one of the more risky given the volatile politics in the region and the market power of OPEC.

Power interconnections in a similar way increase overall system security, and reduce the need for individual economies to maintain high levels of reserve generation capacity.

REGIONAL ECONOMIC DEVELOPMENT

Over the long-term, Asia could benefit greatly from the development of regionally interconnected gas and electricity networks. The large amounts of investment needed to bring such a plan to fruition would provide a tremendous stimulus to economic activity in the region, and promote industrial and commercial development.

Of course, for such schemes to succeed, they depend on the ability to bring natural gas and electricity to markets at competitive prices, no easy task when the world price of steam coal is highly competitive. However, the region is well endowed with resources that can be exploited competitively, and the labour cost structure is relatively low in the developing producer economies, so the commercial viability of these schemes would appear to be reasonably certain.

GLOBAL ENVIRONMENT

Promotion of a regionally interconnected gas network could do more than other policy measures combined to mitigate the greenhouse gas emissions of the rapidly industrialising and developed Asian economies. For power generation, the major use for natural gas, the main alternative is steam coal burned in relatively inefficient boiler units, or fuel oil - but the regional utilisation of this fuel for power generation is declining rapidly where natural gas is available.

One only has to consider the exponential growth in power supply in economies like Malaysia and Indonesia over the last two decades - much of it provided by natural gas fired power plants - to realise the alternative (investment in coal plant), would have resulted in greatly increased CO_2 emissions over that period. Conversely, if the exponential growth in coal-fired power supply in China could somehow be converted to a “dash-for-gas,” the greenhouse gas implications would be truly impressive.

CHAPTER 4

CRITICAL DECISION-MAKING FACTORS AND ISSUES

When individual energy systems are to be interconnected it has to be envisioned what the ultimate shape of the interconnected system will be. For long distance natural gas transportation or power transmission, the flow is usually one-way, a direct export-import arrangement.

But for a relatively short distance or cross-border power interconnections, will the interconnection be one-way or two-way? Is the power exchange done on daily basis or is it affected only during outage or emergency back-ups. If the power interconnection is developed just for the purpose of fulfilling temporary or casual needs, an efficient and active regional energy market is hard to achieve.

Until now, most trans-border power trades or exchanges in Asia are rather of this nature; for backup or emergency support. Such interconnections are not fully utilised for lack of exploitation of the full benefits that can be derived from the existing facilities, or from difficulties that arise due to lack of full compatibility between the power systems on either side of the border.

The following section describes the key factors that energy planners, both on the importing side and exporting may usually consider before deciding on the infrastructure suitable for interconnections.

KEY FACTORS IN INFRASTRUCTURE CHOICE

LOCATION OF RESOURCES

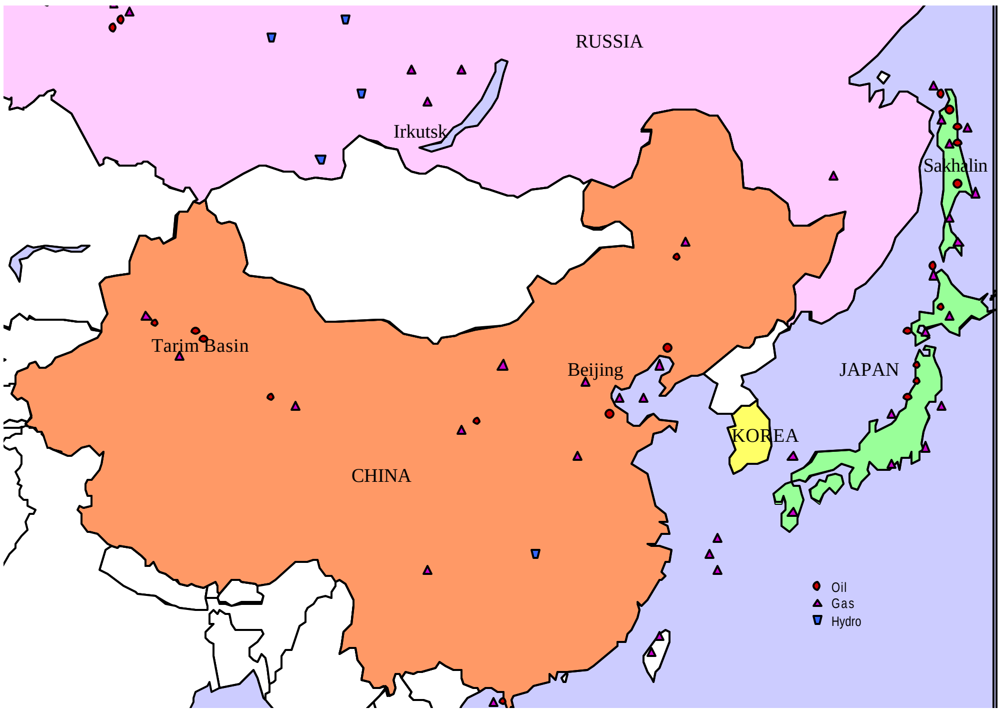
The first consideration with respect to cross-border gas or electricity interconnections is quite naturally the delivered price of the commodity to markets. Important physical considerations are the proximity of the resource to the demand, and the geography of the intervening terrain.

The type of interconnection likely to be favoured depends on the resource, its proximity to markets, the characteristics of demand, and technical factors (such as voltage, frequency and synchronicity of high voltage AC). If the resource is water or low-grade coal (for example lignite), electricity must be generated on-site and the electricity traded (as is the case for electricity imports to Thailand from hydropower resource in Laos PDR).

If the resource is natural gas, the tendency seems to be to favour importation of the primary fuel, for power generation or other uses locally. This gets around technical problems with respect to power systems, and makes more overall economic sense as the value is added locally, and a primary fuel like natural gas has multiple potential applications.

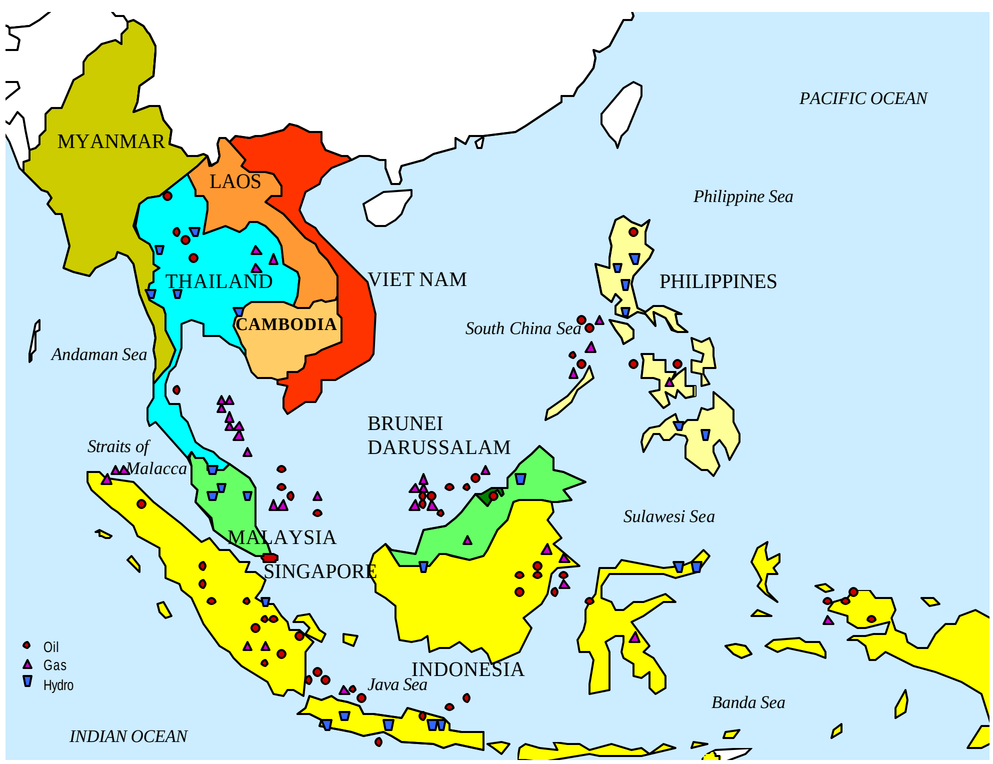
Figure 6 and Figure 7 show the locations of energy resources in Northeast and Southeast Asia, respectively. The reserve quantities, however, are not indicated in the maps. Hence, the maps do not tell which economies are net energy exporters and which are net energy importers. Reports produced by APERC in 2000 provide information on gas reserves and hydropower potential in Northeast and Southeast Asian economies [APERC, 2000a, 2000b, 2000c].

Figure 6 Natural gas, hydropower and oil resources in Northeast Asia



Source: APERC, 2000a and 2000b

Figure 7 Natural gas, hydropower and oil resources in Southeast Asia



Source:
APERC, 2000a and 2000b

MARKET CONSIDERATIONS

On the market side two factors help energy planners in choosing which of the two energy commodities is more desirable: natural gas or electricity. The first factor is to determine the extent of natural gas share with respect to the other fuels in power generation, and the second is to determine the natural gas share throughout the whole economy, both in the power and non-power sectors.

An economy that has traditionally relied heavily on oil or coal for power generation, and which adopts an energy policy that places high importance on security of supply, fuel diversification and mitigation of GHG emissions, will favour importation of natural gas for power generation if it can be made available cost competitively. Natural gas has also become a preferred choice for conversion in older open cycle gas turbine or thermal plants.

Combined cycle power plants have understandably become popular due to reduced capital costs, high efficiency, and rapid start-up times. Even where natural gas or LNG are not price competitive against steam coal for base-load generation, CCGT plants may still be constructed to provide mid-load and peaking power.

Except for gas producing economies like Russia in Northeast Asia, and Brunei Darussalam, Indonesia and Malaysia in Southeast Asia, the share of natural gas in the power generation fuel mix of most Asian economies is still small. For economies like China and the Philippines, the percentage share is insignificant. However, this situation may change radically over the next two decades, especially with respect to China, which has experienced severe environmental and health problems resulting from coal combustion, and is now beginning to encourage natural gas development.

Cross border trade in electricity is an attractive proposition in its own right, and for different reasons than those driving trade in natural gas. As outlined above and in more detail in the APERC report, *Power Interconnection in the APEC Region* [APERC, 2000a], cross-border trade in electricity increases system security and lessens the requirement for reserve capacity.

In some electricity trading situations, notably in Europe and North America, the net cross-border flows may be relatively small. In these circumstances, the interconnection is used primarily to match loads in different markets, and increase the available supply options. For example both Norway and Canada have a high dependence on hydropower, and both have cross-border interconnections to nations with quite different power supply characteristics. This allows producers heavily reliant on relatively cheap hydropower to sell electricity in wet years and buy back in dry years, hence optimising economic efficiency.

Electricity trading in Asia is likely to be quite different to this, and may be less concerned with load balancing than with one-way trading to earn foreign exchange. This is due to the economic inequities and relative resource endowments of neighbouring economies. For example, Laos PDR and Mynamar earn valuable foreign exchange by selling electricity and natural gas, respectively, to Thailand, which has high power demand growth.

An economy that has already achieved a good fuel-mix in its power generation, or has its natural gas supply mainly to serve as fuel for the power sector, will probably encourage the penetration of environmentally low impact fuel in other sectors, namely the industrial sector, commercial-residential sector, and the transportation sector.

Detailed analysis as provided for in the section on **Current Natural Gas Consumption Trends** in Chapter 3 is useful in determining whether natural gas or electricity or both are needed.

INFRASTRUCTURE COST

Gas and electricity network infrastructure will only be developed where cost effectiveness can be demonstrated. The construction of long-distance energy infrastructure incurs such large costs that governments are usually not able or prepared to undertake such endeavours, instead encouraging private firms to make the required investments.

At the specific project level, cross-border natural gas or electricity investments are determined by projected return on investment. This requires detailed cost-benefit analysis at a detailed technical level, and there are many factors that are specific to individual projects. The important factors include:

OVERALL INFRASTRUCTURE DESIGN

Energy demand and supply projections are an important initial criteria, beyond the information that may be available on current actual and potential demand.

In most cases, investors will tend to specify pipeline or transmission line capacities that are just adequate to meet the immediately anticipated demand, and perhaps some short-term growth potential. The reason for this is that although mid and longer-term demand may allow for a significantly larger pipeline or power transmission line at the design stage, the cost of capital will preclude the installation of additional surplus capacity at the construction stage.

This is a major constraint on future growth in demand for gas and electricity, both products that can be heavily dependant on the carrying capacity of transmission lines. This is also an issue where governments can greatly assist the private sector in providing such infrastructure. If governments are willing or able to shoulder the additional financial risks from an oversized transmission system, it would be possible over the longer term to develop a comprehensive regional energy infrastructure more cost effectively than what tends to happen now. Assistance to private investors can be through a number of mechanisms, including favourable royalty or tax concessions [Jensen, 1999].

The 650 km Indonesia-Singapore pipeline is an example of a gas transmission line designed to accomodate future growth. The gas will ultimately fuel three power plants, operated by SembCorp Co-Gen, Tuas Power and PowerSeraya. The line will initially send 9.1 MMCMD to Singapore, but has a total capacity of 19.6 MMCMD, and can be upgraded to 28 MMCMD in the future.

"The first gas arrived on January 3, 2001. It was Indonesia's first gas export to Singapore as well the first gas export via pipeline for Indonesia, which is well known as a liquefied natural gas (LNG) exporter. Under the contract signed by PERTAMINA and Singapore's gas trading firm SembCorp Gas in January 1999, PERTAMINA and its production-sharing contractors will send 9.1 MMCMD of natural gas to Singapore through a 656-km long underwater pipeline.

The production-sharing contractors, grouped in the West Natuna Gas Consortium, are Conoco Indonesia, a subsidiary of American energy firm Conoco Inc., Gulf Indonesia Resources, a subsidiary of Canadian firm Gulf Canada Resources, and British-based Premier Oil.

The gas sales contract will generate revenue of between US$6 billion to US$7 billion for the Indonesian government throughout the 22 years of the contract.

Some of the general details about the pipeline and discussion of the future plans of Indonesia, Singapore and Malaysia are mentioned in the following excerpt from the Jakarta Post, Indonesia's English language daily newspaper [Jakarta Post, 2001].

> The development of the project initially caused controversy, mainly because the bidding for the pipeline construction contract was won by the American firm McDermott, which was accused of having links to former president Soharto's golfing partner Mohammad "Bob" Hasan.
>
> But PERTAMINA stuck to the selection of McDermott as the pipeline contractor, despite strong pressure from many legislators to review the results of the bidding. The consortium has invested some US$400 million for the construction of the pipeline alone. The pipeline is now being operated by the consortium Conoco on behalf of the PSCs.
>
> The West Natuna pipeline, billed as one of the longest in the world, has a capacity of 19.6 MMCMD and can be upgraded to 28 MMCMD in the future. In total, the West Natuna Gas Consortium is committed to investing US$ 1.5 billion on the project, US$ 1.15 billion of which has been spent to get the project started.
>
> The gas will be delivered to Jurong Island (southwest of Singapore), where Singapore has built a multi-billion giant petrochemical and power plant complex.
>
> Separately, Dow Jones news agency quoted SembCorp Gas' general manager as saying that the company had signed up 25 new customers for the gas supplies from West Natuna. SembCorp Gas's new customers bring the total contracted sales to Singapore users to 9.1 MMCMD, with the full contracted volume to flow in the first quarter of 2002. By July this year, the daily imports will be 3.64 MMCMD.
>
> Aside from West Natuna, PERTAMINA is negotiating with another Singaporean firm, Singapore Gas Supply Pte. Ltd. for a contract to supply gas from central Sumatra to Singapore through the island of Batam. PERTAMINA has also signed an initial agreement with Malaysian state oil and gas company PTERONAS for the supply of 7 MMCMD of gas to Malaysia from Conoco's Block B field in West Natuna. The gas will be first delivered to PETRONAS' gas facilities on Duyong Island off Malaysia, from where it will be passed to the Malaysian mainland.
>
> The President of Conoco Indonesia said PERTAMINA and Conoco proposed to connect the West Natuna-Singapore pipeline with the planned gas pipeline linking the Block B field in West Natuna to Duyong. But thus far PETRONAS favoured building a separate pipeline, he said, adding that both parties were still negotiating to choose one of two options. He said that both options would require the same investment of less than US$40 million.

SOCIO-ECONOMIC BENEFITS

If economies that need to import energy have a choice between natural gas or electricity, the preference is likely to be gas imports, as this offers the opportunity for further value-added benefits (for example the development of a gas distribution network for uses other than production of electricity).

If natural gas imports lead to increased overall economic activity for the importer, social and economic benefits may arise from this activity.

However, the final decision of which energy infrastructure to choose is not always obvious. Other considerations, including bilateral or multi-lateral trade arrangements or economic corporation among economies, will eventually decide which infrastructure will be given a priority by the government. The private sector will come in if it finds the project economically viable.

From a local environmental perspective, imported electricity is a clean energy source, but from a regional perspective, the fuel used to generate the power do contribute to GHG emissions and other local pollutants. However, the power generating side receives more benefits in terms of providing employment, and other services associated with the power generation.

TRANSMISSION PRICING

ELECTRICITY TRANSMISSION PRICING

There are a number of methods of calculating transmission prices, the most common being the embedded cost and marginal-cost methods. There are two ways to calculate price on the basis of marginal cost - the short-run marginal cost (SRMC) method and long-run marginal cost (LRMC) method.

EMBEDDED COST METHOD

This method is based on the average cost of transmission service provided. It allocates total costs among different users on a predetermined rule with some equity considerations taken into account. The postage stamp rule, the zoned postage rule, the contract path rule, and the megawatt-mile rule are the pricing rules based on this way of pricing. While this method has advantages with regard to the ease with which it can be applied and the guaranteed recovery of investment costs, there are certain drawbacks such as the equity problem in allocating costs and the reduced efficiency of the system resulting from the less complete reflection of the true costs of transmission services.

Postage Stamp Rule

The costs of transmission service are allocated according to the power volume injected into and taken off the system regarding the transmission system as a whole. This rule allocates costs in accordance with the volume of power transmitted (MWh) or with the maximum contracted volume (MW). It ignores transmission distance (like postage rates) and may be applied to a system that does not suffer congestion. However, since this pricing system does not give appropriate consideration to the costs incurred by system users who cause congestion of the system or who cause greater power losses, inefficient system utilisation and cross-subsidies between users may well result.

Zoned Postage Stamp Rule

This rule adds a location component to the postage stamp rule. It differentiates transmission prices on the basis of the zone in which the points of injection and off-take are located, in a similar way to parcel charges in the postal service. Total volume of power transmitted (MWh) or maximum contract volume (MW) is used to allocate costs. Zones are determined not by the distance but by the degree of congestion within the system in such a way that the border of zones are the buses for which the difference of marginal costs are large due to bottlenecks. In this way, system users who transmit power through bottlenecks pay higher prices.

System access fees are assessed according to the investment costs of transmission facilities and the number of system users, so that the fees are different by the zone. Zonal surcharge is also charged on the basis of the investment cost of transmission facilities that connect different zones. This rule is suited to a system for which system congestion is expected and provides signals for system expansion and reinforcement.

Contract Path Rule

This rule specifies contract paths for system users and allocates costs according to the ratio of the volume of power transmitted to the capacity of the contract path. As the criteria of cost allocation implies, its main purpose is to charge system users in an equitable way under the circumstances where transmission wires are used by more than one user.

Rate-setting is relatively easy under this scheme and the rate itself is said to be more efficient than the postage stamp rule because it takes account of both transmission distance and volume of power transmitted. However, in a situation where there are many independent transmission systems interconnected, remedial procedures are required so as to allow for the discrepancies between the actual path and the contract path of the power flow caused by the loop flow phenomenon.

Megawatt-Mile Rule

This rule allocates transmission costs by evaluating the impacts of power-injecting plants on each transmission line. Although it reflects both distance and power volume, evaluation and application procedures are complex. Also, there may arise an equity problem in the impact evaluation of power flows where there are counter flows and many system users who inject power, raising the issue of the order of power injection.

MARGINAL COST METHOD

Basing the transmission service fee on the marginal cost of providing the service is the common way of charging for a service. It signals the opportunity cost of the service and induces customers to use the service in an efficient way. Marginal cost pricing methodology is divided into the short-run marginal cost method and the long-run marginal cost method according to which marginal cost is used, and into nodal pricing and zonal pricing according to the type of application.

Short-Run Marginal Cost Method

This method utilises shadow cost, that is, social opportunity cost, of each bus supporting optimal power flow and, as such, is recognised as best reflecting competitive market mechanisms. While it sends out price signals that can lead to optimal system operation, there is some difficulty in employing this method of price-setting for the purpose of facility investment because it does not guarantee a full recovery of investment costs. Under this scheme, large price fluctuations may occur according to changing system conditions. Since a system operator may impose an unwarranted congestion charge on system users in the name of optimal power flow, neutrality in system operation needs to be secured and detailed information on cost structure is required.

Long-Run Marginal Cost Method

This method takes into account facility investment requirements and does not require estimation of the short-run opportunity cost of system usage. Since it incorporates long-run costs, most of which are for fixed assets, resulting rates are relatively stable. But it is also limited in equity and efficiency aspects to the extent that the scale and composition of future investment are uncertain, implying large requirements for detailed information on the cost structure.

Nodal Pricing

This method sets the price of transmission service on the basis of shadow costs of buses calculated through power loss between buses and congestion constraints. The shadow cost of bus here reflects short-run marginal cost of transmission service.

Zonal Pricing

This method is similar in nature to nodal pricing, but applies marginal costs for each zone classified by similar system characteristics. Less requirements for information gathering and processing to calculate transmission prices at each node is an advantage over the nodal pricing method.

NATURAL GAS TRANSMISSION PRICING

Pricing principles for natural gas transmission services are the same as for electricity, except for certain attributes resulting from the physical characteristics of natural gas, such as storability and volume flexibility. These physical characteristics play a significant role, not only in transmitting gas but also in maintaining system security. As a result, storage and compression costs take some portion of the total cost of gas transmission. Since the pricing method utilising the marginal cost concept is the same for both electricity and natural gas, the discussion below will focus on pricing methods for different types of service and the issue of allocating fixed costs.

TRANSMISSION SERVICE

In general, the user of the transmission service pays for all or part of fixed transmission costs. Fixed costs are allocated based either on the maximum contract capacity or on mixture of maximum contract capacity and total throughput. Straight-line rates or two-part rates are applied usually.

Interruptible transmission service normally covers only variable costs, but in some cases it also covers some portion of fixed costs. The rate for this service is derived as a flat rate on the basis of throughput or as a combination of straight-line rates and two-part rates. For example, the rate may consist of a minimum payment plus payments for throughput, where the latter may take the form of a straight-line rate or block rate.

Peak load may be defined in different ways: (i) maximum load during certain periods, such as per day and per hour, (ii) expected maximum load during certain periods calculated as an average of actual peak loads, for example, during two peak days or five peak days in the past, or (iii) maximum load under expected extreme system conditions.

Price differentiation for peak loads may take different forms. In pricing hourly peaks, the price is assessed according to real-time metered loads. When a peak load is priced over a period of a certain number of days, either the peak load over the whole period or the average load of the peak day over the period is used. In setting seasonal rates, peak loads over different seasons can be used. Under an extreme system condition, priority of delivery and volumes to be delivered under the constraint of system capacity may be used as criteria for price differentiation.

STORAGE SERVICE

A typical way of determining rates for storage service is as follows. At first, revenue requirements including return on equity capital are calculated. At the next step, revenue requirements are allocated to different functions of storage facilities, namely, injection, storage, and withdrawal and pumping into pipelines. And then, each category of functionally allocated costs is divided into fixed costs and variable costs. Lastly, these costs are distributed to each rate component such as space, deliverability, and volume such as injection and withdrawal.

In the US, in general, 50 percent of fixed costs are distributed to space and the rest is to deliverability. Variable costs are recovered through volume rates. In the UK, they derive an envelope of least costs for various storage facilities, for example, LNG storage facilities, salt cavities, and a depleted gas field relative to duration[5]. Storage facility costs are divided into those related to peak loads (deliverability) and those related to annual storage volume, with the former being recovered through deliverability price and the latter through the price of capacity. Pre-determined durations are offered as a menu in the tariff structure.

ALLOCATION OF FIXED COSTS

As seen in the previous discussion, the way of allocating fixed costs has significant implications for service users as well as service providers. For instance, if more fixed costs are allocated to the demand charge, the risks to the transmission service provider are decreased.

The trend has been for more of the fixed costs to be recovered through demand charges and less through commodity charges or energy charges. This is closely related to the supply and demand situation in the market and market liberalisation. In the US, from 1952 until 1973, pipeline companies usually recovered costs under the Atlantic Seaboard method. This method allocated fixed costs evenly between demand charges and commodity charges. As a way of mitigating the problem of gas shortage, the United method was introduced in 1973, under which 75 percent of fixed costs were allocated to commodity charges. As the gas shortage problem was mitigated and high gas price relative to other fuels became an issue, the Modified Fixed Variable (MFV) method was adopted, under which only a pipeline company's return on equity and associated taxes were recovered through commodity charges. With the issuance of FERC Order 636, the use of the straight fixed variable (SFV) method was mandated. This method stipulates that the commodity charge reflect only the gas price [US-GAO, 1993].

FERC viewed the SFV method advantageous over the previous MFV method in that it could rectify distortions in gas producer decisions and it could better ration pipeline capacity to those who valued it most. Also, it was expected that the SFV method would induce more use of pipelines for off-peak consumption, resulting in more efficient use of the pipelines and decreased pipeline rates.

This transition implies a shift of fixed costs to consumers, with firm service or with low load factors for the benefit of interruptible consumers or those consumers with high load factors in general. Also, it has the effect of lowering cost recovery risks for pipeline companies.

OTHER ISSUES RELATED TO TRANSMISSION PRICING

Cross-border grid interconnections mean not only energy flows between different economies, but also a certain degree of integration of different markets. This has implications on strategic energy security, diversity of energy sources, and energy trade both within and across national boundaries [Transco, 1998].

In an interconnected system in which a sub-system sends energy in only one direction to another sub-system, the effect of market integration may be limited to the extent that the energy receiving system is offered more energy options and the domestic pricing and fiscal policy restrains those systems from being integrated through taxation on import and domestic trade of imported energy. On the other hand, if energy can flow in both directions, the market integration effect may be substantial. And, pricing and fiscal policies will exert an influence on the degree of market integration, but the desire of energy suppliers and consumers for freer and more diverse energy options will tend to make government policies support the energy trade. Therefore, the direction of energy flow and government policies on energy price and taxes can be an important determinant of the efficient use of the pipelines or transmission wires.

In Northeast Asia, for example, where it is expected that energy will flow only in one direction, the price of imported gas through pipelines from Russia will be the most important determinant of its competitiveness against natural gas imported in LNG form from other gas-exporting economies. In Southeast Asia, where many of the economies have indigenous natural gas resources and it is possible to design the system to support two-way energy flow, the price of imported gas and power will determine whether local electric utilities use imported gas to generate power or import electricity. Energy consumers like large industrial consumers will give similar consideration to their energy procurement decisions. And predicted government policies on energy price will determine the profitability of investment in power transmission wires and gas pipelines.

In particular, in an interconnected system where energy can flow in both directions, several factors may affect the price level that final consumers pay for imported energy and, accordingly, the trade volume. They include but are not limited to: energy market structure and ownership structure; price transparency and access to networks; existence and duration of term contracts and possibility of spot trades; and system balancing and reliability requirements. For example, a two-way pipeline system can support a physical delivery of gas from a gas importing system and, as a result, can shave a peak of the system that formerly exported gas. This peak gas may lower the price level in peak periods. Of course, the extent of peak shaving will be affected by the speed of reverting flow and the availability of gas from the adjacent system.

GEOPOLITICAL ISSUES

Geopolitics is an important factor in decision making with respect to trans-border networks. Political confrontations and tensions can significantly affect the development and implementation of energy projects. Multilateral projects, in particular, are vulnerable to international political and diplomatic relations.

Apart from the generally published statistics of energy resources, both Northeast and Southeast Asia have additional offshore hydrocarbon deposits (oil and gas) in disputed territory. These resources are subject to overlapping claims or unresolved boundaries. Most often, resource estimations in these areas cannot be confirmed, nor can they be exploited.

In Northeast Asia, the establishment of regional energy infrastructure networks would have positive impacts in improving bilateral and multilateral political relations, promoting economic development and helping to ease political tensions. Asian markets could provide Russia with more flexibility in developing energy policies, and imports from Russia could benefit recipient economies dependent for energy supplies on other parts of the world where there is potential political instability.

For Southeast Asia, a trans-border energy network would have obvious benefits in integrating the region economically and politically.

Some international activities could facilitate energy market development. For example in Western

Europe the Energy Charter Treaty, which entered into force in 1998, is promoting a new model for long-term energy cooperation based on the principles of the market economy, mutual assistance and non-discrimination. The main focuses are on foreign energy investment protection and secure transit of energy and energy products. Mongolia, Japan and the Russian Federation have already applied to join the treaty and are waiting for ratification by national parliaments. The People's Republic of China has not indicated a willingness to join and it's position remains uncertain.

In Southeast Asia energy is a major sector for economic cooperation between ASEAN member economies. The Agreement on ASEAN Energy Cooperation signed by the foreign ministers of the founding ASEAN members in June 1986 in Manila, and ratified in subsequent years by new members, has become a key instrument in supporting various types of energy activities, including; resource investigation and exploration, energy policy development; energy security, standardisation and manpower training. Energy infrastructure interconnections are awarded a high priority status to encourage energy trading between member economies.

For the whole region, the APEC Energy Working Group is promoting energy cooperation between member economies. APEC Energy Ministers meetings have been held on a regular basis. However, as APEC covers a large area, more specific cooperation programmes should be encouraged among members within particular sub-regions.

KOREAN PENINSULA

Reconciliation processes on the Korean peninsula gained new momentum this year. An historical meeting between the South Korean president Kim Dae Jung and the North Korean leader Kim Jong Il was held in June 2000 in Pyongyang. Among the questions was the issue of infrastructure development. The initial agenda includes road and rail connections. In October 2000, during the visit of the South Korean prime minister Lee Han Dong to Moscow, South Korea expressed an interest in an international logistics project to reconstruct the rail link between north and south and connect it to Europe through the Trans-Siberian railroad. At the end of 2000, North Korea and South Korea discussed a project to reconnect a railway and build a four-lane highway across the heavily fortified border.

North Korea needs international cooperation with respect to energy supply, with power infrastructure a major consideration. The first step was made in 1994 by establishment of the Korean Peninsula Energy Development Organisation (KEDO). This international institution operates on the base of North Korean - US agreement, envisaging construction of two nuclear reactors in exchange for termination of North's military oriented nuclear programme. Cross-border interconnections could facilitate broader power cooperation projects, such as creation of a power grid covering South Korea, North Eastern China, Russian Far East and probably Japan.

South Korean government officials and those from the state owned Korea Gas Corp. were reported saying that a direct line through both Koreas would significantly lower import costs, while boosting economic co-operation between the divided economies. This route could be a final part of the Kovykta supply scheme. There is a possibility that route changes will occur due to increased economic co-operation between south and north [Financial Times, 2000a].

JAPAN - RUSSIA, ISLANDS TERRITORIAL DISPUTE

Japan is the closest and the biggest market for Sakhalin gas and oil reserves. Although Japanese companies participate in upstream developments in Sakhalin off-shore (Mitsui - 25 percent, Mitsubishi - 12.5 percent in Sakhalin-2, and SODECO - 25 percent in Sakhalin-1), their involvement could be higher provided that the territorial dispute is resolved. Japan has claimed sovereignty over the Southern Kuril islands since the end of World War II. Settlement of the Kuril territorial dispute would pave the way for a formal peace treaty and create a new momentum in commercial relationships. Energy upstream development in Eastern Russia seems to be a mutually beneficial theme for cooperation, diversifying Japanese energy supply and providing Eastern Russia with badly needed investments into energy infrastructure.

EU - RUSSIA NEW ENERGY NEGOTIATIONS

High crude oil prices in the year 2000 raised concerns about energy supply security in Europe. As a result of these concerns, Russia-EU energy cooperation has gained new momentum. After a mission to Moscow in October 2000 the European Commission suggested doubling the imports of gas from 130 BCM in 1999 to 260 BCM by the year 2020. Oil and electricity trade developments are also envisaged. New upstream development activities will require huge capital and advanced technologies. Meanwhile existing pipelines are ageing and additional supplies will require construction of new pipeline links from Western Siberia. Total upstream and infrastructure investments are estimated at US$ 70 billion [Financial Times, 2000b]. The sum is reasonable over a 20 year time span with the main investors to come from Germany, France and Italy. The basic framework for this cooperation would be in the form of long-term contracts on energy supply in return for large-scale investments.

Strengthening energy ties with the EU represents a new challenge to a possible eastern flow of Russian energy exports. Although Russia's energy resources in western and eastern Siberia and Far East are sufficient to feed both export directions, the unfavourable locations of these two highly endowed energy resource areas pose huge infrastructure delivery problems. The prospects for east Russian energy developments are looking less bright with the proposed new boost in European exports. Finally, the high risks arising from instability in legislation and political components of the economy could become a major impediment for the development of upstream energy and infrastructure projects where involvement from foreign investors is needed.

RUSSIA TO CHINA - ENERGY TRANSPORTATION VIA MONGOLIA

The shortest Kovykta gas pipeline route from Irkutsk to Beijing would have to pass through Mongolia. With this proposal the pipeline length would be 2,600 km. The Chinese have expressed concerns over the political risks and possible transit fees if the pipeline were to pass through a third economy. China prefers an indirect route in order to avoid the pipeline passing through Mongolian territory. Bypassing Mongolia, however, would increase the length of the pipeline by 1,500 km.

SOUTHEAST ASIA

China - ASEAN: Greater Mekong area hydro-development. China is actively developing the upper Mekong hydro-potential, constructing high dams, changing hydrological regimes along the river and affecting similar projects in ASEAN economies - Myanmar, Lao PDR and Thailand.

Thailand / Malaysia: A joint development area for gas reserves on continental shelves in the Gulf of Thailand has been established with benefits to be shared equally between Malaysia and Thailand. Some tensions arose on the actual terms of upstream and infrastructure development. The location of cross-border pipelines and separation plants is uncertain with two options in the Malaysian Trengganu state and Thai Songkhla province. The choice could affect economic benefits, environmental and social impacts [Financial Times, 2000c].

Indonesia, Aceh: One of the two operating Indonesian LNG plants - Arun, with annual production of 11.5 Mt of LNG is located in the Aceh province, which is agitating for independence. The province receives only a small share of the profits from exploitation of its natural resources, oil and gas. The separatist Free Aceh Movement demands an independence referendum, and has been inspired by success in East Timor.

ASEAN - CHINA - SPRATLY ENERGY DEVELOPMENT

Of the many overlapping claims in Northeast and Southeast Asia, the Spratly Islands (and their surrounding waters) dispute has received widespread publicity. Located in the South China Sea, between Natuna Island (Indonesia) and Palawan Island (the Philippines), the Spratlys are claimed by no less than six governments (Brunei Darussalam, China, Chinese Taipei, Viet Nam, Malaysia and the Philippines). Little is known about the geology of the Spratlys. Valencia stated that the Spratlys consists of “some 35-odd islands, cays, and rocks spread over about 75,000 square nautical miles” [Valencia, 2000] - a source from Viet Nam describes the Spratlys as “a cluster of almost 200 largely uninhabited isles, reefs and rocky outcrops” [Paracels Forum, 2000].

It had been claimed that oil and gas potential exists in the southern part of the region. One Chinese report estimates that there are 225 million barrels of oil equivalent of hydrocarbons, including 25.2 TCM of gas (assuming that 70 percent of these hydrocarbons are gas, as some studies suggest) [US-DOE, 2000]. As long as the disputes exist it is quite unlikely that the reserves can either be proved or developed.

Chinese research has indicated that the area claimed by both Malaysia and the Philippines, includes some elongated pods several kilometres thick, and reefs well suited to drilling platforms. There are also some sedimentary pods under the continental slope in presumed Viet Nam waters to the west of Malaysian shelf claim and along the continental margin off Viet Nam [Valencia, 2000].

Oil and gas is only one factor in these disputes. The Spratlys are considered as ideal bases for sea-lane defence, interdiction, and surveillance (even by outside powers such Japan and the United States).

Viet Nam, Chinese Taipei, Malaysia, the Philippines, Brunei Darussalam and China have all staked overlapping claims over the whole or parts of the Spratlys. In 1974 China seized the Paracel Islands from Viet Nam, 800 km north of the Spratlys. In 1992 ASEAN and China issued joint calls for restraint in staking claims. All, apart from Brunei Darussalam, occupy one or more of the islands backed up with military installations, and the area is the stage of frequent tense stand-offs between the competing parties.

The significance of the Spratlys lies in what surrounds them - the 250,000 square kilometres of shelf waters in the South China Sea. Economic activity is limited to commercial fishing. The proximity to nearby oil- and gas-producing sedimentary basins suggests the potential for oil and gas deposits, but the region is largely unexplored, and there are no reliable estimates of potential reserves, as commercial exploitation has yet to be undertaken.

Of significance to the wider world are the vital sea-lanes that traverse the area, transporting Middle Eastern oil to Japan and the west coast of America. Around a quarter of the world's total sea-borne trade passes through the area every year.

EAST TIMOR & AUSTRALIA OFF-SHORE UPSTREAM DEVELOPMENT

After East Timor gained independence in 1999 and the United Nations established a Transitional Administration (UNTAET), the Timor Sea boundary became an issue between Australia and UNTAET. Australia and Indonesia defined a seabed boundary between them in 1972 and the so-called 'Timor Gap' area, facing East Timor, has been left unassigned. The Timor Gap hydrocarbon basin contains a major share of total oil and gas reserves in the sea. In 1975, Indonesia invaded East Timor and later in 1989 Australia signed an agreement on joint development of Timor Gap resources with Indonesia, sharing evenly potential revenues. Now East Timor is claiming a seabed boundary halfway between itself and Australia, which is the normal practice under the UN's Law of the Sea. In this case 90 percent of Timor Gap reserves would be inside East Timor's economic marine zone, changing the current 50-50 arrangement. The UNTAET believes it has a strong legal case, and this could assist economic development of the newly born independent state. Currently East Timorese economic activity is based on agriculture and fisheries only. The major gas project now underway is the US$1.4 billion Bayu-Undan gas/condensate project [Financial Times, 2000].

CHAPTER 5

NORTHEAST ASIA

POTENTIAL NATURAL GAS PIPELINE INTERCONNECTIONS

According to the 2000 APERC study on natural gas infrastructure development in Northeast Asia, there is enough potential demand to justify a natural gas project in the region, with China, Korea and Japan being possible markets. The Russian Far East and East Siberian regions have enough supply potential to meet future demand from Northeast Asian markets, and there are a number of pipeline projects under consideration. The pipeline that will link Irkutsk to China (Beijing) and Korea and the proposed Sakhalin to Japan link are examples of cross-border pipelines expected to be feasible. In the longer-term view, North Korea (DPRK) may be involved in the network and Japan might be linked to China or the Korean Peninsula by pipeline.

POWER INTERCONNECTIONS IN NORTHEAST ASIA

CURRENT SITUATION

Initial power integration between China and Russia is already being realised in the form of near-border power cross flows, which could be succeeded by bulk power transfers.

Natural Gas Pipeline Infrastructure in Northeast Asia

No trans-border natural gas pipeline exists in the region. China is developing a domestic trunk line network along with the huge Western Gas Pipeline project, which links Tarim to eastern China. The Republic of Korea (South Korea) has already established a nation-wide trunk line. Japan, world's largest LNG importer, has no important trunk line of natural gas yet. However, the great potential of eastern Russian natural gas import will form a regional pipeline network, which will interconnect the gas resource areas, namely Russian East Siberia and Far East (including Sakhalin), and the above-mentioned economies. Various projects and blueprints have been under study.

The Irkutsk project to China and then to the Republic of Korea via Beijing is expected to be the most attractive one. Taking into account the Western Gas Pipeline project that may be implemented soon, the transportation of natural gas from West Siberia and Central Asia through this pipeline will be foreseeable in the future. The Sakhalin gas is searching for export markets, and Japan is top on the list. A pipeline from Sakhalin to Japan is being deliberated though the lack of a trunk line inside Japan may be an important impediment. Sakhalin in Far East Russia, which possesses huge gas reserves, is expected to have a potential to export this resource to China and the Korean Peninsula as well as to Japan in the future.

Despite the potentials, a number of related issues to establish this infrastructure in transporting natural gas across boundaries have been identified.

The Republic of Mongolia was a consumer of Siberian electric power for a long time. The Central Electricity System of Mongolia operates in parallel with the United Energy System (UES) of Siberia at 220 kV. There also exist small power interconnections such as: the Energy System (ES) Chita - Eastern Mongolia and the Krasnoyarskaya ES - Western Mongolia. In previous years, electric power transfers to Mongolia were in the order of 0.3 TWh.

In planning for future power demand increases in Mongolia, the present lines would need to be supplemented with further links. Two options have been considered: construction of 220 kV HVAC transmission line from Irkutsk - Erdenet, or a 500 kV HVAC thermal power plant at Gusinoozerskaya - Ulan-Bator, which could provide an additional 450 - 600 MW depending on grid development in Mongolia.

There are currently no power flows between China and DPRK, but two jointly developed hydropower stations exist in the border region.

The Japanese power system, which is integrated through interconnections between the 60 Hz system in the west and the 50 Hz system in the east and north, has no power linkage to other economies. The Korean (ROK) power system is likewise isolated at the moment.

The power system in Hong Kong, China is connected to mainland China through interconnections owned by the China Light and Power Company (CLP) and connecting with the Guangdong provincial power grid and Daya Bay nuclear plant. There are eight 132 kV transmission lines and four 500 kV/400 kV inter-bus transformers interconnected with Guangdong with a total capacity of over 3,000 MVA [CLP, 2000].

Chinese Taipei, with a total generation capacity of 26.7 GW in 1998, is also an isolated system. The island is about 150-180 km from Fujian province in mainland China. Power system planners face some difficulties in finding sites for new power plants. However, an interconnection between Chinese Taipei and China is not currently being considered because of political differences.

NATURAL RESOURCES FOR POWER GENERATION

In Northeast Asia region, two different groups of economies in terms of energy resources could be found. Russia and China are quite rich in energy resources while the others including Japan and Korea have less.

Compared to the potential hydropower resource in East Siberia (661 TWh/y) and Far East Russia (684 TWh/y), the potential existing in North China (23.2 TWh/y), Northeast China (38.4 TWh/y), Japan (64.9 TWh/y) and Korea (7.6 TWh/y) is limited. In addition, Japan and Korea have almost fully developed their hydropower resources.

Total potential hydropower resources in East Siberia and Far East Russia amount to 134.5 GW, accounting for 81 percent of the Russian total. So far only 7.6 percent of the potential resource has been developed. These areas also have abundant fossil energy including natural gas, oil and coal. In addition, tidal energy could be harnessed by two large tidal power plants at Tugursk and Penzhinsk, with power generation capacity of about 7 GW and 80 GW, respectively.

Russia also dominates with respect to natural gas reserves in Northeast Asia. Natural gas reserves in China are located in the southeast and west areas, far from centres of demand.

In Northeast Asia, oil reserves and production are mainly in Northeast China and Russia (East Siberia and Far East). The production expansion potential in East Siberia and Far East Russia appears to exceed that in China because of the higher reserves to production (R/P) ratios.

The coal reserves in East Siberia and Far East Russia are very large, exceeding those in China where coal is the dominant fossil energy resource.

Japan and Korea have limited energy resources. Compared to the large amount of demand, the indigenous reserves of energy are negligible. The hydro resources in Japan and Korea are relatively important but there is no room for further development. Compared to East Siberia and Far East Russia, the energy resources in the north of China are not significant.

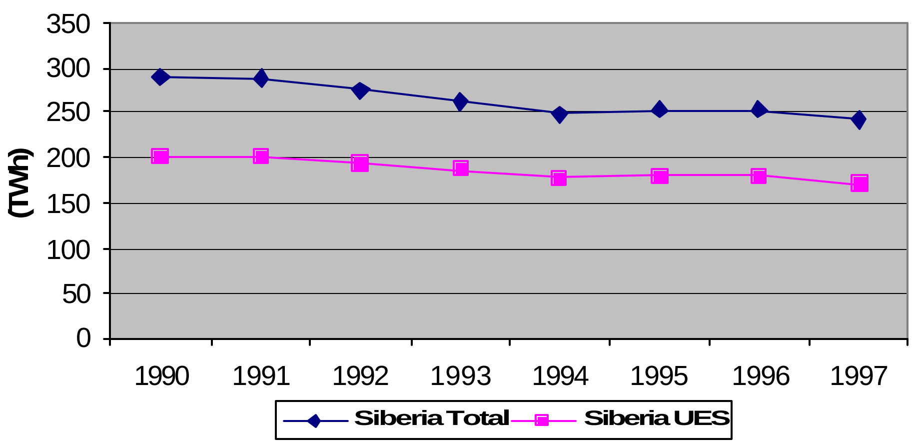
Therefore, within the Northeast Asia region, the economies that are energy-rich tend to have weak demand, but can complement the energy needs of the economically prosperous, but resource poor, economies.

POWER INDUSTRY AND MARKET

The potential electricity demand in Northeast Asia is promising, except in East Siberia and Far East Russia, which are experiencing an economic slowdown and electricity supply surplus. In a longer-term view, northern China, Japan and Korea could be the potential markets for electricity from both the existing plants and future new plants in East Siberia and Far East of Russia.

Since the economic downturn in the early 1990s, electricity supply capacity in Russia has exceeded

Figure 8 Power generation decline in Siberia



Sources: UES of Siberia, (1990-1998).

State Committee on Statistics of Russia, (1997).

State Committee on Statistics of Russia, (1998).

demand by a significant margin. The economic recession in Siberia has caused a decline in electricity demand. Figure 8 shows the decline of power generation in Siberia for an eight-year period from 1990 to 1997.

PROSPECT FOR CHINA'S POWER MARKET

China has achieved strong power demand growth over the last two decades (averaging 8 percent per annum between 1978 and 1998). Until 1997, power supply shortages were considered a bottleneck to economic growth and also a social concern. After slowing down in 1997 and 1998, electricity demand growth is picking up from 1999. The forecast made by APERC in 1998 shows more than 1,500 TWh of additional power supply per annum in total to 2010 (with an average growth rate of 6.5 percent per annum over the period).

On the other hand, in the north and northeast of China, environmental pollution caused by coal combustion is a serious problem. Coal is the major power generation fuel in these regions. Plans now exist to build a natural gas pipeline from recently discovered fields in central China to Beijing to provide a cleaner fuel option for power generation. However, considering the potential demand for gas in Beijing and other Chinese cities, imports from Russia may be required in the future. Therefore, imported electricity from Russia will be a potential solution to meet the fast growing market demand of North China and Northeast China in an environment friendly way.

PROSPECTS FOR JAPAN'S POWER MARKET

Electricity demand averaged 3.4 percent per annum between 1980 and 1998. According to various forecasts, demand will continue to grow at a modest rate. APERC has projected that power generation in Japan will increase by 40 percent over the period 1995 to 2010 (averaging 2.3 percent per annum over the period).

Japan is struggling to achieve its commitment to reducing GHG emissions under the Kyoto Protocol. The effort to contain GHG emissions would be defeated if the use of fossil fuel continue to increase.

Nuclear power and new and renewable energy development were expected to be the alternatives for reducing fossil energy consumption. However, nuclear power related accidents in past years have increased public concerns over the security of nuclear power plants. This is a problem for Japanese energy policy makers, who are relying heavily on nuclear power to mitigate CO_2 emissions. It is believed that achieving even half the planned number of reactors will be difficult in the period to 2010.

Therefore, imported electric power could be treated as a clean supply of energy, especially if the power was generated by hydro or nuclear.

PROSPECTS FOR KOREA'S POWER MARKET

As with Japan, the power system in the Republic of Korea is isolated. The Korean Peninsula has had two independent systems since 1948. The Republic of Korea's power market has experienced steady and high growth, averaging 11.1 percent per annum between 1980 and 1998. APERC projected that power generation in Korea should double over the period of 1995 to 2010 (averaging 4.9 percent per annum over the period).

According to the national energy plan of the Korean Government, total installed generation capacity in the Republic of Korea will be 80.83 GW in 2015, of which 115 will be new generating units with total capacity of 51.59 GW. This will require huge investment and relies heavily on nuclear power.

Nuclear power development could be a serious policy challenge for Korea, as for Japan. Importation of power from Far East Russia or East Siberia would be a possible alternative, through routes across China and North Korea.

PROSPECTS FOR EAST SIBERIA AND FAR EAST POWER MARKETS

Power generation in Russia is primarily gas or coal-fired. West Siberia and the European part of Russia are dominated by gas supply, with the gas share for power generation at 75 percent in 1996. East Siberia and Far East Russia rely mainly on coal, with the share 89 percent in 1996.

POWER INTERCONNECTION POTENTIAL

Given high energy growth patterns in Northeast Asia, supply options need to be as diverse as possible. This has led to a number of innovative power interconnection proposals recently.

EAST SIBERIA-NORTH CHINA

Since 1995, China and Russia have been discussing a power interconnection proposal for transmitting electricity from Siberia to northern China. The governments of both sides have also engaged in a discussion under the framework of Energy Sub-Commission of Regular Premiers Meeting Commission. Investigations and initial negotiations have been undertaken by utilities, assigned grid companies and international interests.

According to investigations and preliminary studies conducted by the two sides, the Irkutsk power system, which is one of the ten components of the Siberian UES grid, is the most suitable exporter of electricity to China.

An initial proposal suggests the construction of a transmission corridor between one of the major hydropower stations in the Irkutsk system and Beijing via Mongolia. The total distance of this corridor would be around 2,500 km. Initial transmission capacity using 600 kV HVDC lines could be 2-3GW with an annual volume of 10-15 TWh. The price and purchase arrangements would be the key issue in promoting this project.

FAR EAST OF RUSSIA-JAPAN

Power generated in Siberia and Far East Russia could be transported directly to Japan through Sakhalin and Hokkaido. A submarine power transmission cable would be required between Sakhalin and Hokkaido (50 km).

The Far East of Russia to Japan interconnection could involve Yakutian hydropower stations (Uchur and Timpton rivers), and gas and coal-fired power plants on Sakhalin Island. It could even be possible to wheel power from Japan to South Korea.

The Russian Joint Stock Company (RAO), the United Energy System of Russia (UESR), and the Russian Academy of Sciences were involved in developing such a concept in 1997. The interest of RAO UESR officials was confirmed in a visit to Japan in August 2000. The target of the "Energo-Most" (Energy Bridge) project is electricity export from Russia (Sakhalin) to Japan. This includes plans to construct two thermal power plants on Sakhalin island: the 4 GW Sakhalinskaya plant fuelled by Sakhalin shelf gas, and the 2 GW Solntsevskaya plant fuelled by coal from the Solntsevsky coal field. Both power plants would be 100 percent export oriented. Power could be exported through a 500 kV HVDC transmission line traversing Sakhalin Island (420 km), plus a 50 km submarine cable through the Laperuza channel with a capacity of 6 GW. The project completion period would be 6 - 8 years; and investments are estimated at a total of US$ 11.9 billion. The power export potential is up to 36 TWh per year.

Japan and the Republic of Korea are considering further nuclear power development as one of the major means of mitigating CO_2 emissions and to guarantee future energy supplies. However, there are hurdles to such plans. Another option would be construction of nuclear power plants in Primorye Krai in the Russian Far East, with the power sold to Korea or to Japan through interstate interconnections (Belyaev et al, 1998).

The load profiles in Japan and eastern Russia are complementary, as the peak load in eastern Russia is in the winter, while in Japan it is in the summer.

THE KOREAN PENINSULA

The Republic of Korea is expected to continue experiencing strong electricity demand growth. Two factors may encourage Korea to consider power interconnections with neighbouring economies. Firstly, there are cost, site and emission constraints on further domestic development. Secondly, at some stage the Republic of Korea may wish to develop a power connection with Democratic People's Republic of Korea (DPRK) as a means of providing aid and reducing political tensions.

The DPRK power system is isolated and has an installed generation capacity of about 6.3 GW, of which 3.2 GW is hydropower, according to DPRK sources [Park *et al*, 1998]. To avoid a supply shortfall in the future, the DPRK will need to either build more capacity or import power. A power interconnection with the Republic of Korea would help to optimise the systems of both economies, especially if further hydropower potential in the north was developed.

In the longer term, transmission lines could extend to China, and perhaps to Russia.

THE FUTURE POWER GRID RING IN NORTHEAST ASIA

As discussed above, a regional power grid would assist in addressing a number of problems, including supply security, environmental impacts, and social conflicts.

Although the overall territory is vast, a future integrated power grid ring through cross border interconnections could be formed as shown in see Figure 9.

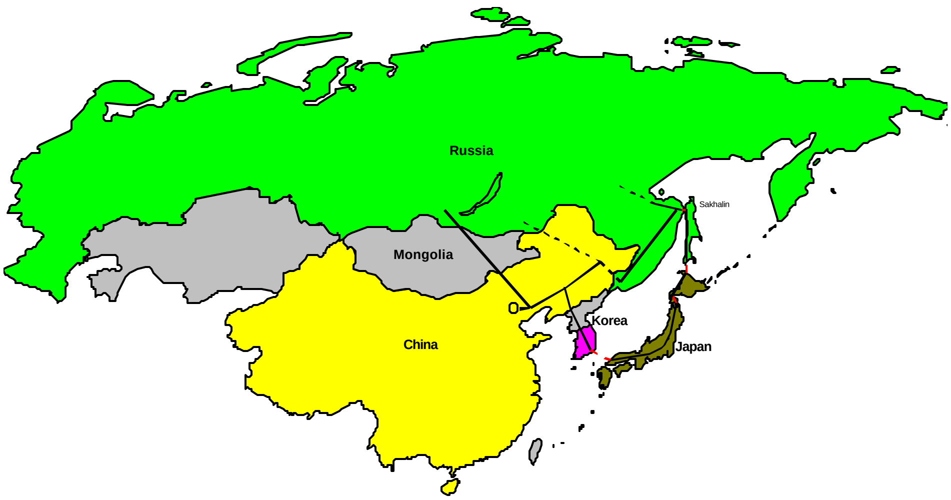
- East Siberia to China through Mongolia;
- China to DPRK, and to the Republic of Korea; and
- Far East of Russia to Japan (with potential link to ROK).

There is significant interest in the installation of a power interconnection between UES Siberia and UES Far East through Northeast China, which is 1,400 km shorter than the route along the Russian-Chinese border.

Moreover, the long-term prospects include the possibility of conveying large amounts of solar power generated in the Gobi desert in west China to the east through this interconnection system [Arakawa & Karto, 1998: Suzuku, 1998].

The Republic of Mongolia was a consumer of Siberian electric power for a long time. The Central Power System of Mongolia, with an installed capacity of 780 MW, operates in parallel with the Electric Power System (EPS) of Siberia through 220 kV power transmission interconnections with the 1,260 MW Gusinoozerskaya power plant in Buryatia.

Figure 9 Potential power grid interconnections in Northeast Asia



Source: APERC, 2000a

RUSSIA-CHINA ELECTRIC POWER EXPORT PROJECTS

Initial power integration between China and Russia is already being realised in the form of cross flows near the border. These could be succeeded with bulk-scale power transfers.

In 1997, the Russian regional power company 'Irkutskenergo' conducted the joint pre-feasibility study 'Russia-China Power Export Project' in cooperation with the State Power Grid Development Corporation of China and experts from PTI of the USA, ABB of Canada, ABB of Sweden and Manitoba Hydro of Canada. The project aimed to export a power surplus of up to 18 TWh per year from the Bratsk switching substation through a proposed +600 kV HVDC 2,600 km long transmission line to the Beijing region in China. The power transfer capacity was planned at 3 GW. The shortest route would have to pass through Mongolia, although an alternative route has been proposed avoiding Mongolian territory. The total estimated construction cost is US$ 1.5 billion. In August 1999, the Chinese government postponed the commencement of the project for at least 5 years due to current power over-supply in the north and north-eastern regions of China. The project could be reactivated when a power deficit develops in these regions.

A second interconnection proposal could link the Amur region in Far East Russia and Kharbin in the northeast region of China. The unfinished Bureyskaya hydropower plant with 2.3 GW planned installed capacity could export 3 TWh per year of surplus power to Kharbin through a 700 km, +400 kV HVAC line. The transferred capacity would be 1 GW. Total investment requirements are estimated at US$ 2 billion, with US$ 0.25 billion for the transmission line and the rest for plant completion.

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS

Currently the Asian gas trade is focused on LNG supply to Japan, Korea and Chinese Taipei from Southeast Asian suppliers and Australia. Contract prices of gas in Asia in 1999 are about US$ 125 per thousand cubic meters. This is about 40 percent higher than in Europe (US$ 90 per thousand cubic mettes) on average and 150 percent higher than in the United States (US$ 55 per thousand cubic metres).

New regional importers who may emerge in the first decade of the 21st century include Singapore, Thailand, the Philippines and the rapidly growing Chinese coastal provinces.

Power generation consumes much of the current as well as projected demand for natural gas. The introduction of new gas turbines having high thermal efficiency and low carbon dioxide emissions, coupled with the fact that such power plants can be built in a shorter time compared to power plants of other fuel sources, makes natural gas even more attractive as a fuel in power plants, either for base load or peaking load. Asian Pacific economies are facing the challenge of diversifying the utilisation of natural gas to the non-electricity sectors, namely the industrial, residential/commercial and transportation sectors.

The world's largest LNG exporters, Indonesia, Malaysia, Australia and Brunei Darussalam are located in the Asia Pacific region. Current proven reserves in Southeast Asia stand at around 6,200 billion cubic metres (BCM) and 1,260 BCM in Australia, which at the current rate of production would last for 41-54 years. Total potential reserves of gas currently stand at around 9,920-10,400 BCM, and based on previous records, chances are good that more gas will be found with further exploration. Natural gas will be the region's fastest growing fuel, with an average annual increase of 3.2 to 4.5 percent [APERC, 1999].

Gas export potential mainly as LNG is estimated for Southeast Asia at 74 BCM/year and 20 BCM/year for Australia [APERC, 1999]. A deficit in East Asian imports of 63-100 BCM/year could be cost-effectively supplied by Eastern Russia. In this case the Russian East will have to compete with LNG suppliers from the Middle East, such as Qatar and Oman who have already signed long term LNG shipment contracts with Japan and South Korea. The APERC Natural Gas Infrastructure Development study [APERC, 1999] identified several options for new gas supplies in East Asia:

- The potentially large Chinese market could not extend its traditional self-reliance policy through development of its own gas resources. Proven Chinese gas reserves exceeded 2,000 BCM in 2000 according to a recent statement by CNPC. Four new big gas deposits have been discovered in Sichuan and Shengsi provinces and in Saidam and Tarim plateaus. The offshore Yacheng field and new reserves explored in Saidam and Tarim basins have recovery gas infrastructure capable of transporting and delivering 150 BCM/year by 2020. LNG supplies are being considered for coastal regions. A 5 Mt LNG plant in the Shenzheng region is scheduled for completion by 2005, and other LNG facilities in Shanghai and Fujian areas are under consideration. Reserves are estimated at 1,100 BCM and are insufficient to meet the rapidly growing demand after 2005. Natural gas in China is mainly consumed in fertiliser and chemical plants, so there exists the need to promote gas use for power generation. Coal to gas substitution in power stations could significantly reduce the environmental burden, especially in big Chinese cities. Gas switching is considered to be a basic element in state environmental policy. The gas share in total energy consumption is projected to rise from 2 percent in 1999 to 6 percent in 2010.

- LNG imports from Persian Gulf suppliers are likely to be less competitive than the supplies from Southeast Asia and Australia due to the long distances involved. In addition, they increase the energy dependence on the Middle East. It is economically reasonable for Middle Eastern exporters to concentrate on the growing Indian market.

Production sharing agreements (PSA) in Russia [APERC, 2000b]

A PSA regime is regarded as the preferred business model for international investors in upstream oil and gas projects in Russia. A PSA involves:

- Obtaining permission rights for sub-soil exploration;

- A special taxation regime according PSA tax legislation; and

- Stable terms in commercial legislation for the whole project life-time (25 years or more).

The current tax burden on net taxable profit for joint ventures in Russia is 104 percent - the figure prohibiting any reasonable deals. The PSA regime provides special taxation rates equal to 68 percent on average creating an attractive investment environment. For instance, higher rates are implemented for PSA projects in such OPEC countries as Indonesia (89 percent), Venezuela (87 percent), Oman (85 percent), Libya (77 percent), Angola (73 percent). In the US, the PSA taxation rate stands at 66 percent for Alaska and 50 percent for other states. It is 83 percent in Norway and 53 percent in Canada.

The Kovykta gas-condensate field in Irkutsk oblast is the largest deposit in East Siberia and the Far East. Proven reserves were recently confirmed at 1,415 BCM (year 2000). Such a giant deposit could justify the construction of a 52-inch diameter 3,360 km pipeline from Kovykta to the Beijing area and then to the port of Rizhao, Shandong province of China, via Mongolia with total transmission capacity of 20-25 BCM after the year 2010. Investments are estimated to be at US$ 1-2 billion for field development and US$ 6-8 billion for the pipeline. Further export options through Rizhao to South Korea and Japan are under consideration. The Russian parliament (Duma) confirmed a Production Sharing Agreement (PSA) regime for the Kovykta field in the final third hearing on 6 December 2000. A PSA is regarded as the most favourable arrangement for attracting investments to develop natural resources in Russia (see box above).

The Korea Gas Corporation (KOGAS) signed an agreement on joint development of the Kovykta field with CNPC (China) and the field license holder 'Rusia Petroleum' (Russia) on 4 November 2000 in Beijing. A three-party feasibility study on the gas pipeline should be completed by the end of 2002. Once the reserves turn out to be sufficient, annual export volumes will be 30 BCM, 20 BCM going to China and 10 BCM to Korea.

In the beginning of March 2000, BP Amoco took a 20 percent stake in CNPC (China) in addition to its stake in the Russian side. BP Amoco confirmed its strategic interests in the Kovykta field and intention to invest up to US$ 10 billion in project development.

There are two other supply options for Russian natural gas to Asian markets:

- Development of the dispersed natural gas field in the Republic of Sakha (Yakutia) with official estimates of 1,024 BCM of recoverable natural gas, which could generate potential export flows of up to 25-30 BCM annually. However, the project for a separate 6,600 km export route to South Korea was suspended in late 1995 as the results of the joint international feasibility study showed that it is not economically feasible. Actually Yakutian gas export plans have merged with development plans for the Kovykta field - the most profitable variant is the link of Sakha and Kovykta gas deposits by a 600-km pipeline.

- The most advanced energy export projects in the Russian East are Sakhalin-1 and Sakhalin-2. The Sakhalin-1 offshore hydrocarbon fields have official recoverable reserves of 190 BCM of natural gas, 11.5 Mt of gas condensate and 65 Mt of crude oil. The project developers are Exxon (USA), SODECO (Japan), Sakhalinmorneftegas (SMNG, Russia), and Rosneft (Russia). According to their estimates, potential recoverable reserves could be significantly higher than official figures. After development of oil and condensate deposits maximum gas export flows could reach 17-20 BCM per year in 2020, which could be processed by the 9 Mt/year LNG plant to be built in Southern Sakhalin, then sent to Hokkaido through the La Perouse Strait sea-bottom pipeline. Another viable route option is through Nevelskoy Strait to Komsomolsk-na-Amure and Khabarovsk industrial areas and further to North-Eastern China where the oil transport network is in place.

The Sakhalin-2 project is being developed by a consortium of Marathon (USA), Shell (Netherlands), Mitsui (Japan), Mitsubishi (Japan) and Rosneft/SMNG (Russia). It is the first project under production-sharing law in Russia. Offshore deposits have been officially estimated at 336 BCM of natural gas, 29 Mt of condensate and 65 Mt of crude oil. Export oriented gas flows could reach 16 BCM/year around 2020 taking the same routes as in Sakhalin-1.

Another potentially hydrocarbon rich field - Sakhalin-3 (Exxon, Mobil, Texaco, Rosneft/SPMG) is under exploration. The prospective structures of Sakhalin-4, 5, 6 give probable geological estimates for all Sakhalin offshore fields of 4,000 BCM of natural gas and 1,500 Mt of condensate and crude oil. New fields (Sakhalin 3-6) could be confirmed for production-sharing agreements by the newly elected Russian parliament (Duma).

Sakhalin: In February 2000 Sakhalin-2 partners Royal Dutch/Shell (62.5 percent), Mitsui (25 percent), Mitsubishi (12.5 percent) launched a tender for the construction of a 6 Mt/year LNG export terminal at the southern end of Sakhalin to be linked by a cross-island pipeline with their offshore Lunskoye field. A possible new market for the project would be 5 Mt/year LNG import terminal in Guangdong, China, to be constructed by 2005.

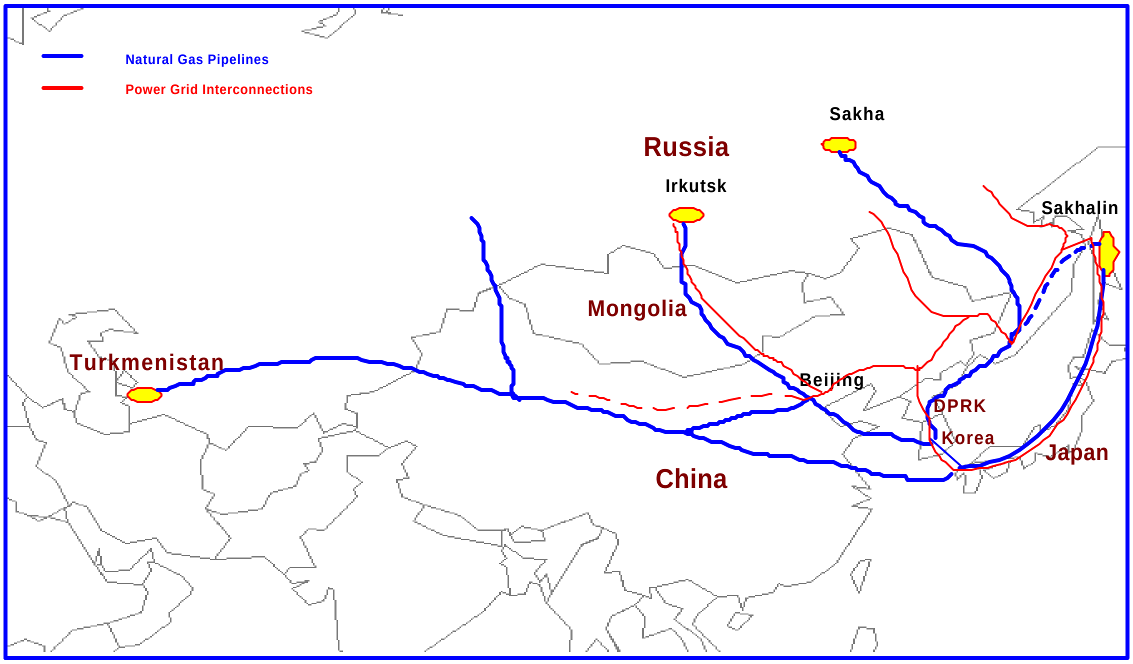
THE COMPLEMENTARITY OF INTERCONNECTIONS IN NORTHEAST ASIA

Northeast Asia, East Siberia and Far East Russia are areas that have the potential to provide cross-border electricity generated by hydropower or by thermal power with gas, coal or oil as a fuel source. Nuclear power could even be a possible source of exported power. Endowed also with adequate reserves of natural gas, these areas could export gas by pipeline to neighbouring economies. The locations of energy resources and markets, as well as the geography, would determine which projects make the most economic sense.

Irkutsk to Northern China (Beijing, for example) and the Korean Peninsula and Sakhalin to Japan are the common possibilities considered. The key question is how will imported electricity or electricity generated with imported gas (via pipeline connection) fare in marketplaces that could be relatively deregulated in the not too distant future. Coal-fired power in China currently enjoys a cost advantage because the ready availability of low-grade domestic coal. Without policy measure to factor in the external costs of using this fuel, imported electricity would find it difficult to compete. This would be less an issue in Japan, where the high domestic cost structure and lack of indigenous energy resources might allow imported electricity to compete on favourable terms. Korea is in a similar situation to Japan, but the industry cost structure is lower.

With Irkutsk endowed with abundant hydropower resources, the Irkutsk to Beijing power interconnection could bring hydropower into China, instead of power generated using fossil fuels, including gas. Japan has the option of importing both electricity and gas from Sakhalin and Siberia, but electricity imports would probably be the more economically attractive given the limited existing gas distribution networks.

Figure 10 Proposed gas and power interconnection routes in Northeast Asia



SCENARIO ANALYSIS

Figure 10 shows the proposed gas pipelines and power grid interconnections discussed earlier. Studying these routes carefully reveal parallel proposals for both gas pipelines and power grid interconnections from Irkutsk, Sakha and Sakhalin.

IRKUTSK TO CHINA AND FURTHER

SOURCES AND ROUTES

Natural gas and hydropower resources in East Siberia are concentrated in the same area in the north of Irkutsk (west of Lake Baikal).

The potential routes for a natural gas pipeline from Irkutsk (Kovykta) to China and for power transmission lines from Irkutsk (Bratskaya) to China lie along a similar corridor.

MARKET COMPETITION

Although China is currently not experiencing high electricity demand growth, further sustained economic growth will result in demand for electricity growing strongly once more, perhaps again reaching the 7-8 percent average annual growth in power supply experienced through the mid 1980s until the mid 1990s.

With clean energy sources a policy imperative, China could be a good market for hydropower from Irkutsk and natural gas from the same region. Given the strong recent commitment by the Chinese government to develop the natural gas industry, pipeline imports could be quite attractive to supplement city gas supplies from domestic fields.

Natural gas for domestic consumption is desperately needed in China to reduce the dependence on polluting low-grade coal.

SAKHALIN / FAR EAST RUSSIA TO JAPAN

SOURCES AND ROUTES

Sakhalin-2 and Sakhalin-1 hydrocarbon projects are in the advanced stages of exploration and development. Gas is likely to dominate production. The Sakhalin-2 developers are considering the export of LNG for the Japanese or Chinese markets, while Sakhalin-1 developers are considering the possibility of pipeline routes to these markets. There is also a plan to export gas-fired and coal-fired electricity from Sakhalin to Japan.

Whatever the route option, a pipeline would have merit with respect to a future larger scale development, and LNG facilities may be the right solution for an initial stage, smaller scale development.

MARKET COMPETITION

Although Sakhalin Island has both coal and natural gas, any power link between Sakhalin and Japan would most likely be based on gas-fired generation. The question is whether it makes more sense to export electricity to Japan or gas. As already noted, a pipeline promises to be a high cost option given the very high cost structure with Japan for such a scheme, and the currently limited nature of domestic gas distribution systems (which tend to be discrete privately owned networks linked closely to LNG terminals).

Japan will need significant additional power supplies in the near future according to the 1998 APERC Outlook and other projections. As Japan has accepted a tough target for CO_2 mitigation under the Kyoto Protocol, any fossil fuel options, including natural gas, will lead to net increases in greenhouse gas emissions. Power imports get around this problem, as the exporter takes responsibility for the greenhouse gas emissions, and in the case of Russia, there is a current net greenhouse gas deficit.

TRANS KOREAN PENINSULA INTERCONNECTION

The trans-Korean Peninsula interconnection is something one could envisage in the longer term, and is dependent on the normalisation of relations between North and South Korea. The most likely scenario would be a natural gas pipeline from Russia, going through China, North Korea and into South Korea. Such a proposal, with consumers taking gas along the route, could be cost competitive with LNG.

A power interconnection between North Korea and South Korea would probably be beneficial to both economies, improving security of supply, and matching the hydropower in the north with coal, gas and nuclear generation in the south. A trans-peninsula interconnection to China would be attractive from a system management perspective, but as none of the economies being discussed have a large potential surplus of competitive power, it is hard to envisage major trading in electricity between all three economies.

FAR EAST RUSSIA/SAKHALIN TO CHINA/KOREAN PENINSULA

The proposed link of the Northeast China power grid to the Russian Far East (Maritime Energy System - ES) is expected to facilitate the integration of the UES Siberia grid with the Maritime system. These systems are not interconnected at the moment.

The natural gas pipeline proposal from Sakhalin to China/Korean Peninsula is an alternative to the route of Sakhalin to Japan.

WESTERN CHINA TO EASTERN CHINA

The natural gas pipeline project from western China (Tarim) to eastern China (Shanghai) has been approved by Chinese government and is about to go ahead. The possibility of feeding West Siberian gas into the line is being investigated. A number of international interests are also looking at the possibility of bringing gas from Central Asia to this line. It is not clear yet whether such proposals have been taken into account the design capacity of the proposed pipeline.

CHAPTER 6

SOUTHEAST ASIA

BACKGROUND

The Southeast Asian economies, under the umbrella of ASEAN (Association of Southeast Asian Nations) have for many years been engaged in cooperative energy programmes. Although the ASEAN Energy Cooperation Agreement was signed by ASEAN Foreign Ministers in June 1986, and reinforces cooperation in all energy sectors, cooperation among state-owned and private oil, gas and power companies has been occurring fore a long time.

The concept of a Trans-ASEAN Gas Pipeline (TAGP) was first discussed in 1990. This was followed by a study called the Masterplan on Natural Gas Development and Utilisation undertaken in 1995 and 1996, which mapped out possible pipeline linkages between major gas reserves and demand centres in Southeast Asia. The ASEAN Council on Petroleum (ASCOPE), an association of Southeast Asian state-owned oil and gas companies following up with a proposal, updating it to include more economies (that have since joined ASEAN) and taking into consideration the active and latest development of cross-border pipelines.

The development of a Trans-ASEAN Power Grid (TAPG) lies within the responsibility of the Heads of ASEAN Power Utilities/Authorities (HAPUA), an association of state-owned power utilities. Established in 1981, HAPUA worked on a number of joint programmes and projects, of which power interconnection is among the highest of its priorities.

The importance of ASEAN energy cooperation was further underscored in the 1995 Bangkok ASEAN Summit Declaration, which stated, “ASEAN shall ensure greater security and sustainability of energy supply through diversification, development and conservation of resources, the efficient use of energy, and the wider application of environmentally sound technologies”. This aspiration was reinforced in the “ASEAN Vision 2020”, as agreed in the Informal Summit in December 1997 in Kuala Lumpur, calling for cooperation activities “to establish interconnecting arrangements for electricity, natural gas and water within ASEAN through the ASEAN Power Grid and a Trans-ASEAN Gas Pipeline, and promote cooperation in energy efficiency and conservation, as well as the development of new and renewable energy resources”.

The Trans-ASEAN Energy Network, as the two networks are sometimes referred to, is an important issue that was a focus of the latest meeting of ASEAN energy ministers in July 2000 in Ha Noi. The Ha Noi Plan of Action of 1998 provided additional direction towards this vision, to be implemented during the period 1999-2004.

Southeast Asian energy ministers urged the relevant organisations to speed up plans for power and gas pipeline grids in order to boost energy security in view of the volatility of world oil markets. They also underlined the importance of developing master plans for the power grid and gas pipeline systems. ASCOPE expects a gas pipeline master plan to be completed in 2001 and a working group set up by HAPUA will address the viability of electricity interconnection projects. Their tasks will include looking into regulatory issues to facilitate associated commercial activities and future energy trading.

NATURAL GAS PIPELINE INTERCONNECTIONS

The Southeast Asia region possesses abundant natural gas resources and is currently the world's largest LNG exporter. The regional policy direction which emphasises energy supply security, diversification of fuel sources to reduce over-dependency on oil, and more intra-trading of energy commodities have driven the Southeast Asian economies to co-operate more closely with respect to gas utilisation and infrastructure development.

Currently more than 70 percent of the natural gas consumed is used as fuel for power generation in the region, with new power plants using CCGT technology producing electricity with high thermal efficiency and low carbon dioxide emissions (see Chapter 3). The biggest challenge yet for the region is to diversify the use of natural gas to the non-electricity sector, namely the industrial, residential/commercial and transportation sectors.

EXISTING CROSS-BORDER PIPELINES

MALAYSIA - SINGAPORE PIPELINE

The first cross-border pipeline was completed in 1992, and involved Peninsular Malaysia's national pipeline (PGU-II) of 714 kilometres being extended at its extreme south by a few kilometres to Singapore, with an export capacity of 4.2 MMCMD. Delivery of gas started with 480 MMCM (432 ktoe) in 1992 before it reached the contract capacity of 1,294 MMCM (1,165 ktoe) in 1996. The 15-year gas supply contract will expire in 2007. All of the gas supplied by this pipeline is used to run major power stations.

MYANMAR - THAILAND PIPELINE

Southeast Asia's second cross-border pipeline came into existence when the Myanmar- Thailand project was completed in late 1998, connecting Myanmar's Yadana gas-field to Thailand's power plant in Ratchaburi. The 649-kilometre pipeline was designed with a total flow-rate of 18.2 MMCMD, with 3.2 MMCMD of the gas to be domestically used by Myanmar, and 14.7 MMCMD to be exported to Thailand. Due to the delay experienced by Thailand's power utility company, the Electricity Generating Authority of Thailand (EGAT) in installing all the combined-cycle gas turbines, only 1.82 MMCMD was transported to Ratchaburi in November 1998.

In 2000, the contracted volume of the Yadana-Ratchaburi pipeline was supposed to be increased to 10.2 MMCMD. With the delay in completion of the Ratchaburi power plants, due to the financial crisis and reduced demand for electricity, Thailand was unable to take the contracted volume of gas.

Another Myanmar-Thailand pipeline from Myanmar's Yetagun gas-field to Ratchaburi is scheduled for completion in 2001. This pipeline will be connected to the existing Yadana-Ratchaburi pipeline at the Myanmar-Thailand border, bringing in additional gas imports to Thailand by 5.6 MMCMD. Had the original Yadana-Ratchaburi and Yetagun-Ratchaburi plans run smoothly, the gas from Yetagun was destined for combined-cycle units at Ratchaburi and Wangnoi, northeast of Ratchaburi. A separate 153-kilometre pipeline has been constructed from Ratcaburi to Wangnoi to transport gas to the Wangnoi power plant.

It was anticipated originally that the Ratchaburi and the Wangnoi projects, when fully, completed would be able to utilise all of the gas imported from Myanmar [APERC, 2000c]. The latest developments is shown below, in a press release by Thailand's PTT.

WEST NATUNA - SINGAPORE PIPELINE

Southeast Asia's third cross-border pipeline, with a total length of 656 kilometres, connects Indonesia's West Natuna gas-field to Singapore, with the delivery of gas starting in the first week of January 2001. Despite some disagreement by legislators in the new government of Indonesia when it was formed in late 1999 as to the appointment of the main pipeline contractor, the project went ahead and was completed ahead of time with gas delivery made four months ahead of time. As mentioned in Chapter 3, the agreed contract volume was 9.1 MMCMD to Singapore. The pipeline, however, was designed for a flow capacity of 19.6 MMCMD and maximum capacity of 28 MMCMD (with upgrade), suggesting that Singapore would import more gas from Indonesia in the future with this pipeline (see Chapter 3).

"Ratchaburi Province, December 22, 2000, at the Region V Operations Center of the Petroleum Authority of Thailand (PTT), His Excellency Suwat Liptapanlop, the Minister of Industry, presided over "the Valve opening Ceremony for Natural Gas Transmission via Ratchaburi Gas Pipeline to the Wang Noi Power Plant ".

Upon its completion, the Ratchaburi-Wang Noi Pipeline has delivered natural gas from Myanmar to fuel the Wang Noi Power Plant of the Electricity Generating Authority of Thailand at Ayuthaya Province since November 15, 2000. Around 280 million cubic feet per day (MMSCFD) of the gas is used at its 3 combined cycle units with a total capacity of 2,000 megawatts.

The 30-inch diameter and 154-kilometre long pipeline, under PTT's second Gas Pipeline Master Plan, has a delivery capacity of 300 MMSCFD presently and can increase further to 500 MMSCFD in the future. The pipeline is mainly designed to connect the gas pipeline from eastern part with the western part as a network, which will result in the economy's energy security enhancement, in case the gas flow on either side faces hiccup. Moreover, it is a significant infrastructure to promote the expansion of natural gas usage in industry sector in the central and western regions of the economy.

In addition, the project will enable PTT to accelerate make-up gas from Myanmar for which it had already been paid in advance in 1998 and 1999 and therefore relieve the interest burden. This will also benefit Thailand's economy as a whole since the price of gas being paid in advance is much lower than today's gas that coincides with the rising world oil prices.

PTT first received gas from Myanmar for commissioning and delivered it to Ratchaburi Power Plant in late 1998 and later to Tri Energy Co., Ltd (TECO), an independent power producer (IPP) in late 1999, respectively. At present, gas supply to feed these two power plants totals 500 MMSCFD. From 2001 onward, gas from Myanmar secured by PTT is expected to reach 900 MMSCFD to accommodate demand of Ratchaburi Power Plant, TECO, and the Wang Noi Power Plant." [PTT, 2000]

CROSS-BORDER PIPELINES IN DEVELOPMENT

TRANS THAI-MALAYSIA PIPELINE

The Trans Thai-Malaysia Pipeline connecting Thailand and Malaysia, is now under construction after the Gas Sales Agreement was signed on 30 October 2000. Total pipeline distance is 423 kilometres, with the first phase of the pipeline connecting Block-A of the Malaysia-Thailand Joint-Development Area (MT-JDA) to Songkhla on the east coast in Thailand's border (277 kilometres, 34-inch diameter), and inland from Songkhla to Changlun in Kedah of Malaysia (96 kilometres, 36-inch diameter). The delivery of gas at an initial rate of 11.05 MMCMD for 20 years is expected to start in mid-2002. Latest developments indicate that the project will be deliberately delayed by one-year as slower growth both in Thailand and Malaysia caused by the economic crisis has slowed demand for natural gas.

In the second phase of the project, additional gas (8.4 MMCM) from Block -17 of the MT-JDA will add further supply to the Trans Thai-Malaysia pipeline. This will be made possible by the installation of a 28-inch diameter 50 km pipeline connecting Block-17 to Block-18.

At Changlun, Malaysia, the Trans Thai-Malaysia Pipeline will be connected to the existing Phase III of Peninsular Malaysia's domestic pipeline, the Peninsular Gas Utilisation pipeline (PGU-III) which stretches from the central part of the peninsula to the Malaysia-Thailand border. The delivery of gas in 2002 with Malaysia and Thailand taking the gas in equal share (50:50) will mark the completion of Southeast Asia's fourth cross-border gas pipeline. More information about the Trans Thai-Malaysia pipeline was described in the previous APERC report Natural Gas Infrastructure Development in Southeast Asia [APERC, 2000c].

Because Thailand has a surplus of natural gas, it has negotiated with PETRONAS (Malaysia) to take 100 percent of initial production. The partners have announced that Malaysia will take Thailand's share for at least five years of the agreement.

WEST NATUNA - MALAYSIA PIPELINE

On 5 October 2000, PETRONAS of Malaysia and PERTAMINA of Indonesia signed a sales and purchase contract for the supply of natural gas from Indonesia's West Natuna field to Peninsular Malaysia. This 20-year contract will earn US$ 6.2 billion revenue for Indonesia. This agreement is the first implementation of a Memorandum of Collaboration in Strategic Alliance and Synergistic Business.

The first delivery of 2.8 MMCMD of gas is expected in July 2002. The export volume will increase to 7.0 MMCMD in 2004. The gas will come from Conoco's Block B field in West Natuna. It will first be delivered to the PETRONAS gas facilities on Duyong Island off Malaysia, from where it will be passed to Peninsular Malaysia.

In mid-January 2001 PETRONAS and PERTAMINA were still contemplating the exact route of the pipeline. PERTAMINA and Conoco, two production contractors of the West Natuna Gas Consortium that were responsible for the production and transmission of gas from West Natuna to Singapore were keen to connect the West-Natuna pipeline with the planned gas pipeline linking the Block B field in West Natuna to Duyong Island. PETRONAS, however preferred building a separate pipeline.

SUMATRA-BATAM-SINGAPORE PIPELINE

Singapore Power (SP) had signed a letter of agreement with Indonesia's PERTAMINA in September, 1999 for the supply of natural gas from three fields in the Jambi area of Central Sumatra, starting in 2002. The gas supply will increase from an initial quantity of 4.2 MMCMD (150 MMCFD) in 2002 to 9.8 MMCMD in 2008. The majority of supply will go to power generation, principally by PowerSenoko.

As mentioned in the previous APERC report, a domestic transmission pipeline has been built connecting Asamera fields in Jambi and Duri gas fields, together with a 137- kilometre loop to Sakerman in the island of Sumatra. From Sakerman there would be another 370-kilometre pipeline to Batam Island,

and 23-kilometre distribution pipelines in Batam. One line will further transmit the gas to the northern part of Singapore, where PowerSenoko is located.

Hence, by mid-2003, within just over a decade of the start of Southeast Asia's first cross-border interconnection, five economies will be interconnected, namely, Malaysia, Indonesia, Myanmar, Thailand and Singapore. There will be six cross-border pipelines, totalling 3,112 kilometres of distance (if distance here is counted from the gas source to the market) and a total flow capacity of 51.65 MMCMD (1,845 MMCFD). The interconnections are, referring to gas flow or export direction; Malaysia-Singapore, Myanmar-Thailand, Indonesia-Malaysia, Thailand-Malaysia and probably Indonesia-Malaysia (see Table 12). The Indonesia-Malaysia (or West Natuna-Peninsular Malaysia) pipeline, when completed, will mark the first pipeline interconnection between two major gas exporting economies in Southeast Asia.

A sketch map showing the routes of the existing pipelines and pipelines under construction is shown in Figure 11.

Table 12 Cross-border pipelines in Southeast Asia (2003)

	Economies connected	Total distance (km)	Initial flow capacity (MMCMD)	Year/ expected year of completion	Other remarks
PGU II – Singapore	Malaysia, Singapore	714	4.2	1992	
Yadana – Ratchaburi	Myanmar, Thailand	649	14.7	1998	At Myanmar-Thailand border the Yetagun pipeline is connected to the rest of the Yadana-Ratchaburi pipeline
Yetagun – Ratchaburi		170	5.6	2001	
West Natuna – Singapore	Indonesia, Singapore	656	9.1	2000	
Trans Thai – Malaysia	Thailand, Malaysia	423	11.05	2002/3	
West Natuna – Malaysia	Indonesia, Malaysia	--	2.8	2002	
Sumatra – Singapore	Indonesia, Singapore	500	4.2		
TOTAL		3,112	51.65		

FUTURE DEVELOPMENT - THE TRANS-ASEAN GAS PIPELINE

A Master plan that aims to link all of the economies in Southeast Asia with gas pipeline infrastructure was prepared from 1995 to 1996. The Trans-ASEAN Gas Pipeline (TAGP) is under formation but its exact routing will be determined by gas availability and market requirements, and financed and constructed by state-owned oil and gas companies in partnerships with multi-national companies. The routing is shown in Figure 12.

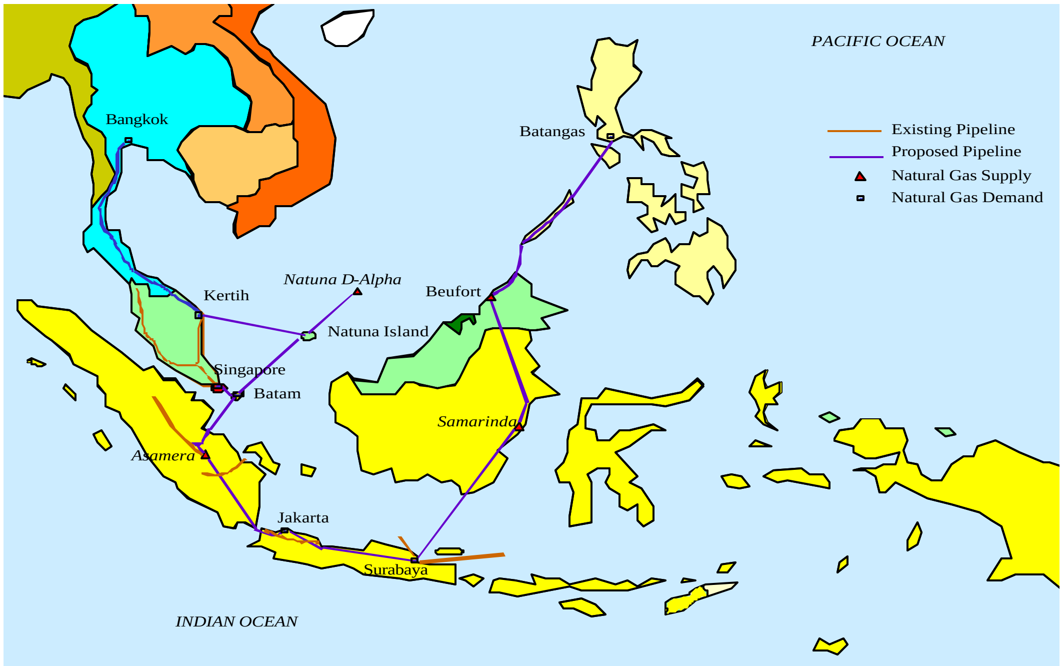
The study which proposed the TAGP concept conducted by ASEAN in 1995/96 estimated that it would cost the region around US$10-15 billion to build a regional pipeline network which could meet demand until 2020. ASCOPE is updating the study to include new ASEAN member economies (Viet Nam, Myanmar, Laos PDR and Cambodia). Investment and business potential with respect to natural

Figure 11 Map showing existing and planned cross-border pipelines in SE Asia

gas infrastructure development are therefore likely to be high over the next two decades in Southeast Asia.

As can be clearly seen, the pipeline routing proposed in Figure 12 differs from the existing pipeline routings in Figure 11. Figure 12 shows hypothetical major trans-border pipelines connecting to form a network, joining major gas fields to demand centres in Southeast Asia. Figure 5 actually shows the regional pipeline in the making, where development in its first stage will focus on trans-border pipelines, and later these cross-border pipelines may be interconnected to local pipeline networks. For example, when the Trans Thai-Malaysia pipeline is completed in 2002 (or 2003), this pipeline will be connected to the Malaysia-Singapore pipeline, with Peninsular Malaysia's PGU network being the link between the two pipelines. This arrangement would enable Malaysia in the future to feed Singapore with gas from the Malaysia-Thailand JDA.

Figure 12 Map showing proposed Trans-ASEAN Gas Pipeline in 1996



Source: APERC, 2000c

POWER GRID INTERCONNECTIONS

In considering the existence and prospects for power grid interconnections in Southeast Asia, the non-APEC economies in the region, particularly those in ASEAN (Cambodia, Lao PDR and Myanmar), should be included. So far in Southeast Asia, a number of power grid interconnection projects already exist and many new projects are proposed (see the APERC 2000 report Power Interconnections in the APEC Region, for more details).

Existing projects include Thailand-Lao PDR commissioned in 1968, Peninsular Malaysia-Singapore and Peninsular Malaysia-Thailand (Stage 1) commissioned in the early 1980s and Peninsular Malaysia-Thailand (Stage 2) which is now under construction. Fourteen power interconnection projects have been proposed by HAPUA (see Table 14).

CURRENT SITUATION ON POWER INTERCONNECTION

THAILAND-LAO PDR

Electric power cooperation in Southeast Asia was first established when Thailand and Lao PDR exchanged electricity in 1968. From 1968 to 1972, the Electricity Generating Authority of Thailand (EGAT) sold electric power to Lao PDR for Nam Ngum Dam construction through a 115 kV transmission line from EGAT's grid at the Nong Khai Substation. After the completion of Nam Ngum hydropower station (installed capacity of 150 MW) in 1978, almost all of the generated power from this plant was transmitted to Thailand.

The power cooperation between these economies significantly expanded in volume in 1993, when the governments of Thailand and Laos signed a MOU for the export of up to 1,500 MW of electricity to

Thailand by 2000. The MOU was again renewed in June 1996 to increase power exports to Thailand to 3,000 MW by 2006. Since the signing of the MOU, several hydropower projects with a total installed capacity of 3,796 MW have been proposed. Among these projects, The NamTheun-HinBon and Houay Ho hydropower plants were completed and have been in commercial operation since 1998 and 1999 respectively, including two 230 kV double circuit transmission lines from the plants to EGAT substations.

PENINSULAR MALAYSIA-SINGAPORE (TNB-SP)

Tenaga Nasional Berhad (TNB) and Singapore Power (SP) are interconnected from Plentong in Southern Peninsular Malaysia to Senoko Power Station in Singapore via 2x250 MVA, 275 (TNB side)/230 (SP side) kV overhead line (12 km) and submarine cables (4 km). The project was commissioned in 1985. The objective of this interconnection was to provide mutual back-up supply during extreme system emergencies for both power systems.

PENINSULAR MALAYSIA-THAILAND (TNB-EGAT) STAGE 1

TNB and EGAT are interconnected between Chuping in Northern Peninsular Malaysia and Sadao in Southern Thailand via a 117 MVA 132 kV 26.7 km long overhead line. The project was commissioned in 1981 with maximum transfer of 80 MW. The objective of this interconnection was also mainly for providing a power supply source during extreme system emergencies for both interconnected power systems. The trading of energy between the utilities enables peak shaving and optimisation of production costs.

PENINSULAR MALAYSIA-THAILAND (TNB-EGAT) STAGE 2

TNB-EGAT Stage 2 interconnection is designed to provide more power transfer efficiency with larger volume of power exchange between the two utilities. It is a 112-km long 300 kV HVDC point-to-point link with initial power transfer of 300 MW, to be expanded to 600 MW later. The project is now under construction and will be completed in the year 2001.

Table 13 shows the details of the Thailand-Lao PDR, Peninsular Malaysia-Singapore and Peninsular Malaysia-Thailand interconnections.

OPERATING EXPERIENCE AND BENEFITS

Generally, the first objective of the interconnections is to improve the reliability of supply of the economies involved, Lao PDR, Malaysia (Peninsular Malaysia), Singapore and Thailand. The generation reserve margin of these economies (especially areas close to the interconnection lines) can be reduced due to the greater system security offered by the linked systems. For example, with the interconnection of Malaysia and Singapore with an individual generation capacity of about 12,000 MW and about 6,000 MW respectively, the resilience of both power systems has improved greatly as a result of their combined system size [Biyaem, 1998].

The second objective is to improve the quality of power supply in the areas especially during disturbances and emergencies on both sides. On several occasions, the interconnections between these economies, either between Peninsular Malaysia and Singapore, Peninsular Malaysia and Thailand or Thailand and Lao PDR, has enabled these economies to supply each other during times of need. The interconnections between them had long been considered as a source of power in addition to what they already had in their own economies. Thus, the interconnection has been proven to increase the security of supply.

Like other interconnections that already exist in the other parts of the world such as those in Europe and North America, the interconnections between these economies also bring significant economic benefits. They enable utilities to defer capital investment for new generation, as a result of sharing of spinning reserve and reserve margins. It has been regularly used for peak shaving as the system peak demand of TNB and that of EGAT's southern network are non-coincidental [Jaafar, 1998].

The individual economies may now operate at a lower reserve margin and subsequently defer investment in new plants but the demand load is still reliable and secure. With these interconnections, overall

Table 13 Existing interconnections in Southeast Asia

	Thailand - Lao PDR	Peninsular Malaysia – Singapore	Peninsular Malaysia – Thailand	Peninsular Malaysia – Thailand
Interconnection			Chuping – Sadao (Stage I)	Gurun – Khlong Ngae HVDC link (Stage II)
Date of Commission	1968	1985	1981	Expected to be completed in the year 2001
Details of Interconnection	- Between EGAT of Thailand and Power Authority of Lao PDR (EDL). - Nam Ngum Dam. In operation since 1972. Currently, the generating capacity is around 150MW and about half of the power generated is exported to Thailand. - Xe Set Hydropower. In operation since 1991 with capacity of 45 MW. Most of the power generated is exported to Thailand.	- Between Tenaga Nasional Berhad (TNB) of Malaysia and Senoko Power Station of Singapore - The interconnection via 275/ 230 kV transformers, two circuits of 2 x 300 sq. mm overhead lines and 2x 250 MVA submarine cables operated synchronously at 230 kV - Improves the resilience of power system at both sides due to the combined system size. - Maximum power transferred over the past years - No commercial arrangement	- Tie line operated radially at 132kV due to system constraint for synchronous operation. - Between TNB's Chuping 132 kV substation to EGAT's 115 kV Substation at Sadao. - Via 2x66.7 MVA 132/115kV transformer and a 117MVA 115kV overhead lines - Maximum power transferred is 80 MW - Able to provide optimised production costs as well as sharing of reserves during emergencies	- Bukit Keteri to Sadao, to improve and upgrade the current system with HVDC lines. - A point to point HVDC connection of 110 km HVDC lines (85 km in Malaysia and 25 km in Thailand) from TNB's Gurun 500/ 275kV to EGAT's Khlong Ngae 230 kV substation. - Meant to bipolar operation and energised at 300kV DC - Initially the power transfer capability at this stage is 300MW but could be upgraded to 600MW

Source: Jaafar, 1999

additional capital expenditure requirements for capacity expansion are reduced, as the interconnections allow the most cost effective solution to the problem of supply.

Furthermore, interconnections allow the use of larger generating units due to the enlarged power systems in the economies concerned. The above interconnections bring about larger system inertia and a larger distribution of units participating in frequency control such that the tripping of any unit will not affect frequency performance.

Apart from those benefits, these interconnections in some ways could improve political relations between these economies and result in a closer regional cooperation.

PROSPECTS FOR FUTURE POWER INTERCONNECTIONS

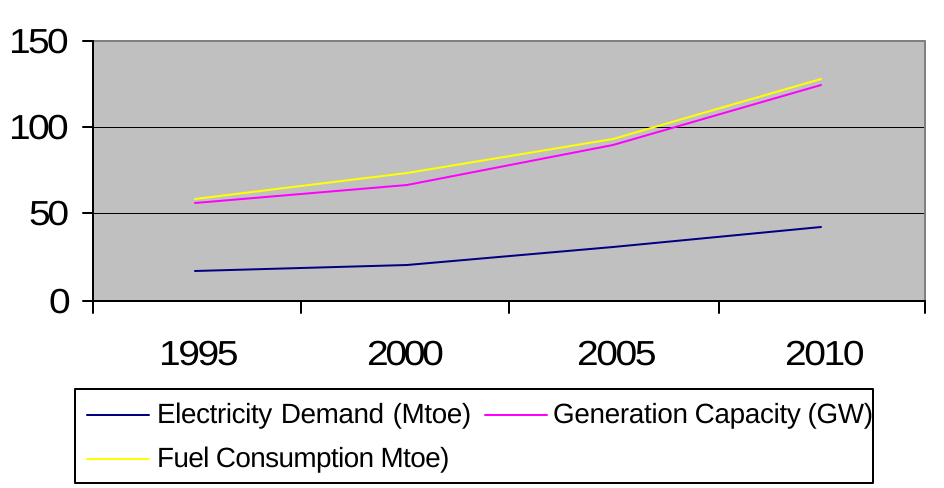
POWER INDUSTRY AND MARKET

Energy is essential to Southeast Asia's economic and social development and particularly critical to the region's industrialisation efforts. Even with the economic slowdown, electricity demand growth is projected to be more than 5 percent annually over the period of 1995-2010 [APERC, 1998].

The total electric power generating capacity in the six APEC economies in Southeast Asia is 56 GW (1995). With the abundance of rich energy resources such as oil, gas, hydro, coal and renewables, power development has become a flagship programme for ASEAN energy cooperation. Figure 13 and Figure 14 show the rapid electricity sector growth trends expected in Southeast Asia for both B98 and PCS scenarios in the 1998 APERC Outlook.

Moreover, power sector reforms and a conducive policy environment for domestic and private invest-

Figure 13 Electricity projections for SE Asia - Baseline Scenario



Source: APERC, 1998

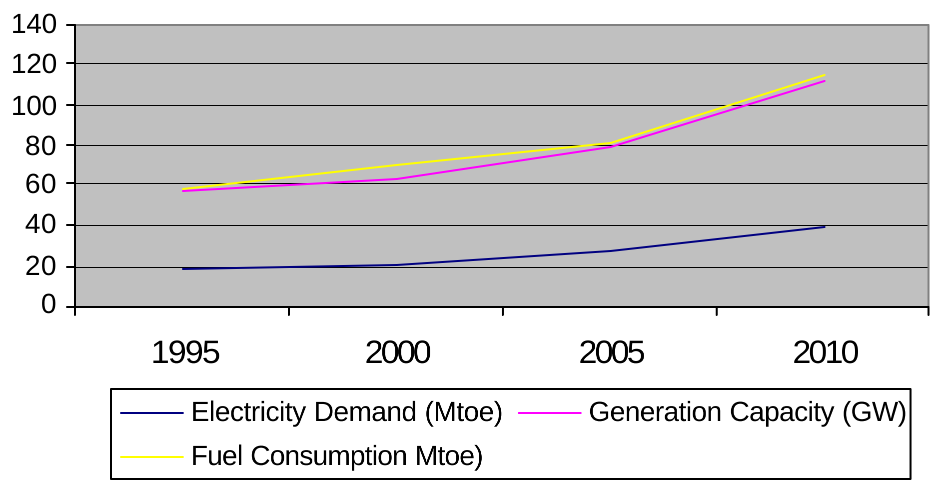
Note: In the projection, Southeast Asia includes 6 APEC member economies. Viet Nam was not included since it joined APEC later.

ment in power supply are in place in some member economies. This could generate the much-needed capital requirements for power infrastructure build-up.

One plausible strategy under the ASEAN Vision 2020 is the realisation of the energy interconnection infrastructures for the Trans-ASEAN energy network consisting of the ASEAN Power Grid and the Trans-ASEAN Gas Pipeline Projects, which will require business synergy between and among the private sectors in Southeast Asia.

Preliminary studies on a possible interconnection between Singapore and Batam Island (Indonesia)

Figure 14 Electricity projections for SE Asia - Protracted Crisis Scenario



Source: APERC, 1998

Note: In the projection, Southeast Asia includes 6 APEC member economies. Viet Nam was not included since it joined APEC later.

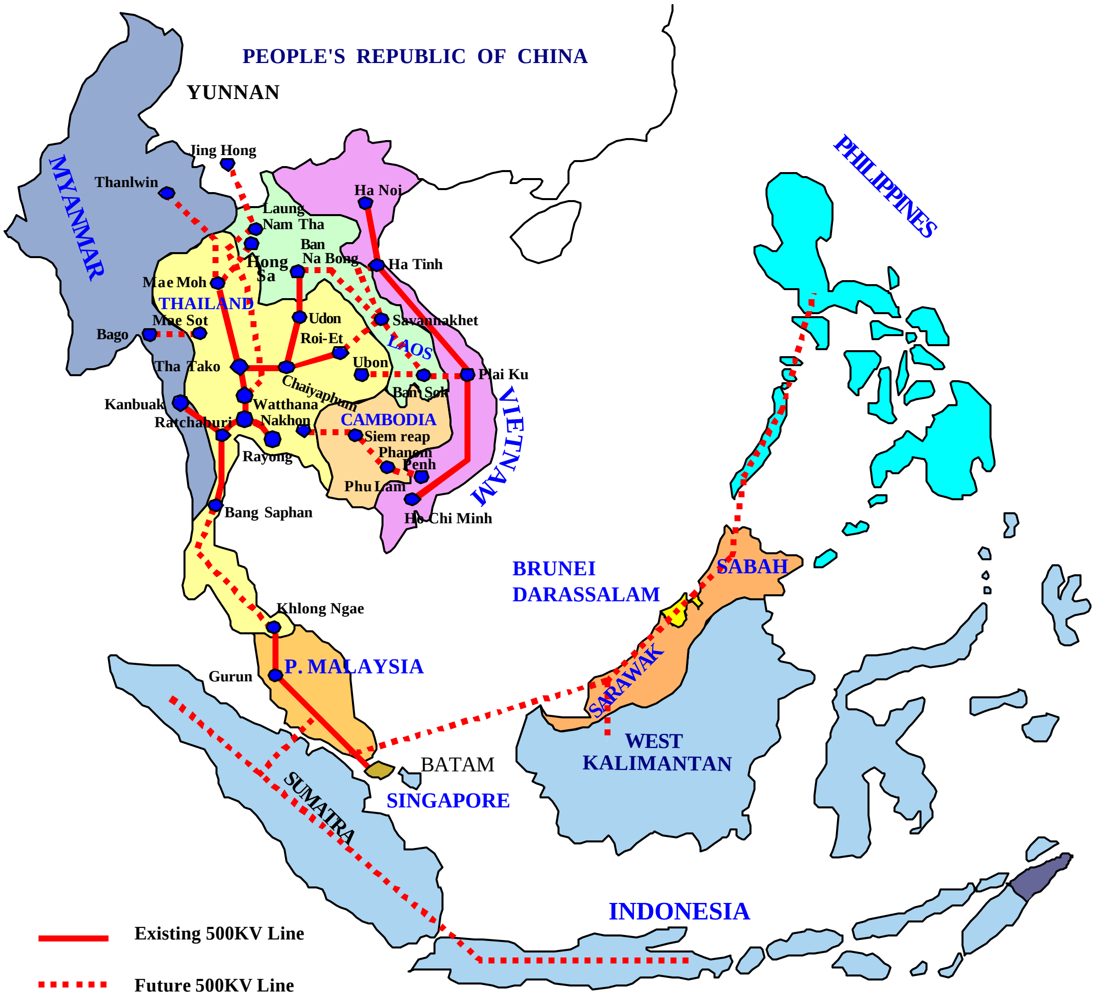
have been undertaken. This would involve a 500 MW power plant using gas on Batam island and exporting power to Singapore. Natural gas for the project was to come from the Asamera fields in Sumatra (a pipeline from Asamera to Batam is being constructed by Indonesia PGN Gas). However, in a Gas Agreement signed between parties in 1999 it was proposed that natural gas from West Natuna fields in Indonesia will be supplied to Singapore via a 640 km submarine cable in 2001. This project was completed a few months ahead of time and the gas started flowing from West Natuna to Singapore in the first week of January 2001. Therefore the power interconnection proposal will probably be re-assessed. It would now appear to be more economical to build the proposed power station in Singapore rather than on Batam Island as originally proposed. In addition, Singapore may end up with excess generation capacity, and this may dampen the implementation of this project. ASEAN power interconnection projects are presented in Figure 15.

Apart from the interconnections between Thailand-Lao PDR, Peninsular Malaysia-Thailand and Peninsular Malaysia-Singapore, the implementation of other ASEAN power interconnection projects have been delayed due to financing constraints and the presently unfavourable economics of long distance transmission lines. The status of projects is presented in Table 14.

The Greater Mekong Sub-Region (GMS) - Cambodia, Lao People's Democratic Republic (PDR), the Yunnan Province of China, Myanmar, Viet Nam and Thailand - has significant potential for cross-border power trade. The power networks of these economies are almost independent. The economy of this region is very diverse and the electricity demand growth is high. According to the recent study by World Bank on “Power Trade Strategy for the Greater Mekong Sub-Region” [World Bank, 1999], under the base case scenario the power demand will grow from 131 TWh (21 GW) in 1997 to 597 TWh (92 GW) by the year 2020 with annual average growth at 6.8 percent.

The sub-region is well endowed with low-cost hydro resources, such as those in Lao PDR, Myanmar, and Yunnan Province of China. Among GMS economies, on the demand side, Thailand has the largest increase in electricity consumption accounting for more than 65 percent of the GMS total demand (411 TWh) by the year 2020 and on the hydro potential side, Yunnan province has the largest hydropower potential accounting for 48 percent of total potential in the region. Large differences in energy demand

Figure 15 Southeast Asia power interconnection projects



Source: Chonglertvanichkul, P., 2000b

and potential between GMS member economies provide opportunities for cooperation in the energy sector.

Table 15 shows total exploitable hydroelectric energy estimated at 847 TWh, of which only 21 TWh (3 percent) of the total hydroelectric energy in GMS has been exploited.

POWER COOPERATION

Since the 1970s, the six GMS member economies have been considering ways of coordinating electricity infrastructure investment and various social and economic activities to strengthen their competitive position and growth prospects.

The first agreement was power purchase between Lao PDR and Thailand, when the Nam Ngum 1 hydropower plant in Lao PDR with 30 MW of installed capacity was completed in 1972 and an additional 120 MW added in 1978.

Table 14 Status of interconnection projects in SE Asia

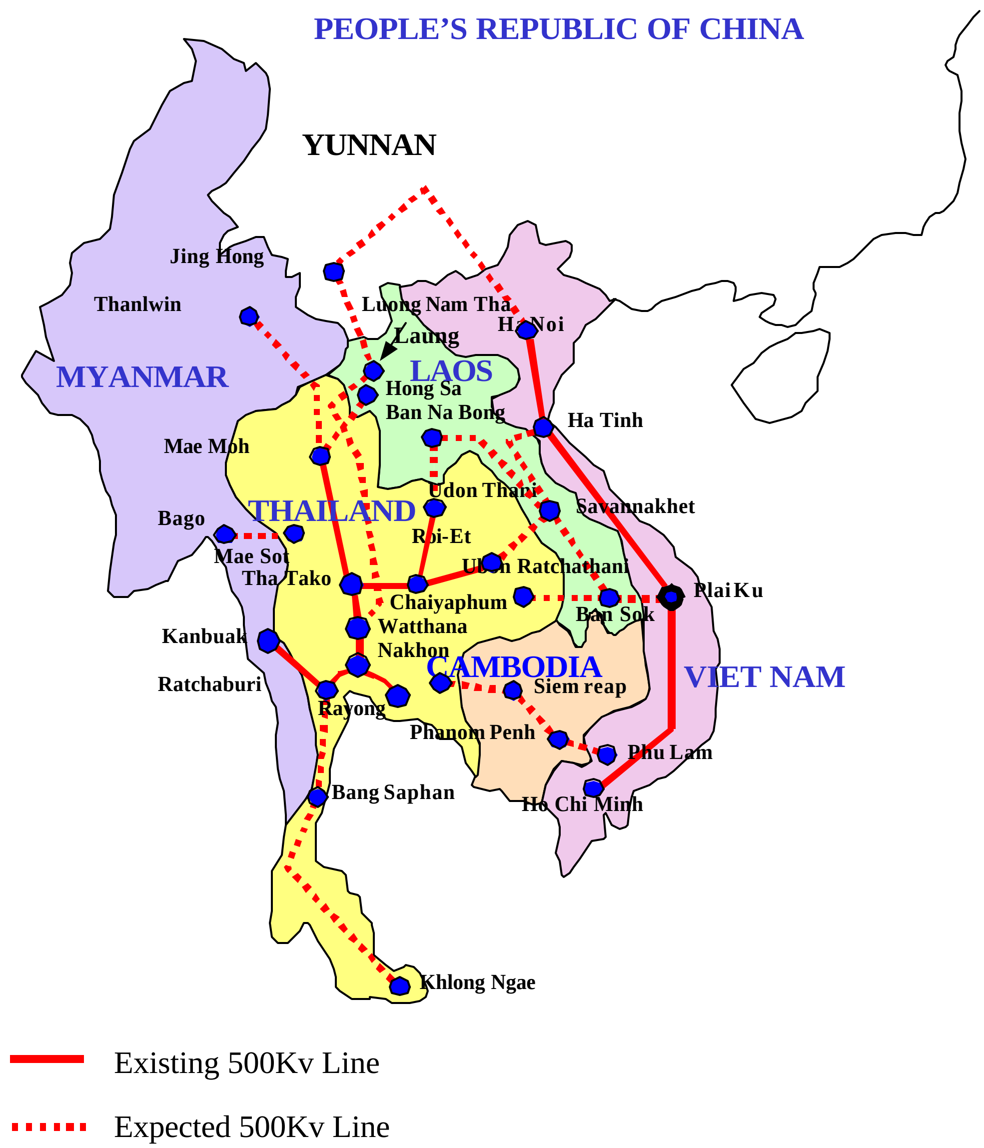
	Projects	Status
1	Peninsula Malaysia – Singapore	Operating synchronously since 1985 under zero electricity exchange Improve system resilience due to larger combined size and short time transfer during emergency. TNB is reinforcing its 275kV in the southern Peninsular Malaysia. A double circuit 500kV line from Permas Jaya to Bukit Batu and Yong Peng will be commissioned at the end of year 2000 and initially energised at 275kV
2	Peninsula Malaysia – Thailand	
	Bukit Keteri – Sadao	In operation since 1981 with power transfer capability up to 80 MW
	Gurun – Khlong Ngae (HVDC)	Project in progress and targeted for completion in 2000
3	Sarawak – Peninsula Malaysia (submarine cable HVDC 500Kv and HVAC 275 kV)	This project originally planned to transmit to Peninsula Malaysia 2100 MW of electricity from a 2400 MW Bakun hydropower project in East Malaysia. However the Bakun project has been scaled down for domestic consumption due to financial crisis that hit ASEAN region recently and the interconnection project has been deferred indefinitely
4	Sumatra, Indonesia – Peninsula Malaysia (submarine cable)	Project aimed for bi-directional electricity flow. MOU has been signed by both parties for the development of a mine power plant in Sumatra, Indonesia Funding is the constraint for project implementation, however the feasibility study for this project is expected to commence soon.
5	Batam, Indonesia – Bintan, Indonesia – Singapore – Johore, Malaysia	Seeking sponsors for financing the study, however it needs to be reassessed
6	Sarawak, Malaysia – West Kalimantan, Indonesia (150 kV, 250 MW overhead line)	Implementation being prepared with options for the private participation, however since the last report in 1997 no progress has been made on the project
7	Sabah, Malaysia – Philippines	Seeking sponsors for financing the study
8	Sarawak, Malaysia – Brunei – Sabah Malaysia (275 kV overhead line)	Pre-feasibility study completed and seeking sponsors for financing the feasibility study
9	Thailand – Lao PDR	Discussed in details in the section "GMS Interconnections"
	Nam Ngum Hydro Power Plant - EGAT	In operation since 1972.
	Xe Set Hydro Power Plant- EGAT	In operation since 1991 with the capacity of 45 MW. Most of the power generated is exported to Thailand.
	The Nam Theun-Hin Boun -EGAT	In operation in 1998
	The Houway Ho -EGAT	In operation in 1999
	Hongsa – Mae Moh	No progress has been reported.
	Ban Na Bong – Udon Thani	
	Savannakhet – Roi Et	
	Boloven – Ubol Ratchathani	
10	Viet Nam – Lao PDR	New project. Discussed in details in the section "GMS Interconnections"
	Central Viet Nam – Central Lao PDR	
	Central Viet Nam – Southern Lao PDR	
11	Thailand – Myanmar	New project. Discussed in details in the section "GMS Interconnections"
12	Viet Nam – Cambodia	New project. Discussed in details in the section "GMS Interconnections"
13	Lao PDR – Cambodia	New project. Discussed in details in the section "GMS Interconnections"
14	Thailand - Cambodia	New project. Discussed in details in the section "GMS Interconnections"

Sources: Biyaem, *et al*, 1998; Chonglertvanichkul, P., 2000; and Jaafar, F., 1999

In June 1993, the Thai and Lao PDR Governments signed an MOU agreeing on the development of power projects in Lao PDR to export 1,500 MW-3,000 MW of power capacity to Thailand over the period 2000-2006 through 230 kV and 500 kV transmission lines. Although the economic crisis happened in 1997-1998 in the region, the power purchase from Lao PDR will still be included in the power development plan under generic projects of 1,600 MW in 2006 and 1,700 MW in 2008 respectively

In 1990, the Thai Government appointed a Thailand-Myanmar Border Hydroelectric Project Committee to be responsible for coordination with the Myanmar Government over development of hydroelectric projects. Thailand and Myanmar formally signed a memorandum of understanding (MOU) in 1997 for Thailand to buy up to 1,500 MW of capacity from Myanmar by 2010. Based on that MOU, in the following year a series of hydroelectric projects and a combined cycle power project were considered for electricity sales to Thailand with a total of 5,555 MW installed capacity. Due to power shortages

Figure 16 GMS power interconnection projects



Source: Chonglertvanichkul, P., 2000b

Table 15 APEC economy natural energy resource potentials (for 1999)

	Crude Oil (Billion bbls.)	Natural Gas (Tcf)	Coal (Billion tonnes)	Hydropower* (GW)	Hydropower* (TWh)
Thailand	0.8	14	2.3	15	49
Viet Nam	2.7	12.7	3.5	18	80
Myanmar	0.2	7.4	0.3	38	125
Cambodia	Na.	Na.	Na.	8	41
Lao PDR	0	0	0.9	18	102
Yunnan	Na.	Na.	23.5	90	450
Total	3.7	34.1	30.5	187	847

Sources: AEEMTRC, 1999
Notes: *exploitable capacity and generation

in Myanmar at present, power supplies from Thailand have been supplied to relieve the problem in the short term. In addition, Thailand and the Union of Myanmar have a contract deal to export natural gas to Thailand.

In 1993, the Yunnan Provincial Electric Power Cooperation (YPEPC) of China and the Electricity Generating Authority of Thailand (EGAT) discussed the development of hydroelectric projects in Yunnan and the planned sale of electricity to Thailand [Biyaem, 1998]. Two hydropower projects, Jinghong and Mensong were proposed for power export to Thailand through interconnections across Lao PDR. With the progress of studies on the development of the Jinghong project, the Government of Thailand and China entered into an MOU in November 1998 for power export of 3,000 MW to Thailand by 2017.

Recently, Thailand and Cambodia have signed a MOU for a Power Sector Cooperation Programme. The MOU will mainly focus on power trade, joint project development, and training and technical assistance. The joint feasibility study will include power supply to three bordering provinces of Cambodia: Banteay Meachey, Battambang and Siem Reap [Chonglertvanichkul, 2000]

In 1998, Viet Nam and Lao PDR Government signed an MOU to supply 2,000 MW of power from hydropower plants in Lao PDR to Viet Nam by 2010. However, due to the lower electric consumption growth rate than expected in Viet Nam, the plan for import of electricity could be delayed by 3-5 years (by 2015).

In 1999, an MOU was signed by Vietnamese and Cambodian governments to supply power from Viet Nam to Cambodia through a 230 kV transmission line. One year later, Viet Nam's Minister of Industry and Cambodian Minister of Industry, Energy and Mines signed in July 2000 a five-year electricity deal. Starting in 2003, Viet Nam will provide electricity to Cambodia's capital, Phnom Penh, and a number of provinces along the border between the two economies. The capacity will be from 80 MW in 2003 to 200 MW in 2005. For the long term, when electricity infrastructure is in place in Cambodia, electric power will be sent back to Viet Nam through the expected 500 kV transmission lines between two economies.

Lao PDR and Cambodia have just begun deliberations on power cooperation. There is a possibility of joint development of a number of hydropower projects in the Sekong-Xesan Basin, which covers the Southern Lao PDR, Southern Viet Nam, and the North-eastern Cambodia for power export to Thailand

and Viet Nam. In 1999, a cooperation agreement on supplying electricity to towns along the borders and to StrungTreng city was signed between Laos and Cambodia.

It appears that the Greater Mekong Sub-region member economies are increasing their power trade. Also, they are supported by regional and multilateral agencies in their integration efforts. Especially, according to the latest news in November 2000, The Association of Southeast Asian Nations agreed to include Japan and South Korea, two potentially large sources of funds, into a cooperation framework for development of the Mekong River basin. Obviously, this will speed up implementation of projects relating to power trade in this sub region.

PROSPECTS FOR GMS POWER NETWORK

Thailand-Lao PDR Interconnection: The first four GMS regional power interconnection projects in operation were Nam Ngum1-EGAT, Xeset-EGAT, Nam Theun Hin Boun -Sakon Nakhon, and Houway Ho - Ubon Ratchathani (EGAT) which supplied electricity to Thailand with a total export capacity of about 520 MW through 115 kV and 230 kV transmission lines (Please also refer to Table 16). In addition, one other transmission line under construction is Nam Leuk-EGAT (115kV). The 500 kV transmission links will be designed to receive electricity from power plants in Nam Theun Basin and in southern Lao PDR (Roi Et-Savanakhet) and from hydroelectric plants, Nam Ngum 2, Nam Ngum 3 and others in the northern Lao PDR (Udon Thani-Ban Na Bong (Longsan)), as well as from Hong Sa thermal power plant (Mae Moh-Hong Sa).

Viet Nam-Lao PDR Interconnection: The main connection between Viet Nam and Lao PDR will be two 500 kV transmission lines in Nam Theun (central Lao PDR) - Hatinh (central VN) and BanPam or Ban Soc (southern Lao PDR) - Playcu (central Viet Nam).

Viet Nam-Cambodia Interconnection: In the medium-term, 115 kV and 230 kV transmission lines from the south of Viet Nam will connect these two economies. In the more distant future, when the electricity supply infrastructure in Cambodia is in place, power would be exported back to Viet Nam through a 500 kV transmission line.

Viet Nam-China Interconnection: A 500 kV transmission line will be connected from northern Hanoi network to the southeastern Yunnan power system beyond 2015.

Yunnan (China)-Thailand Interconnection: 1,200 MW power out of Jinghong hydroelectric plant's 1,500 MW will be transmitted by a 500 kV line via northern Lao PDR (Luong Nam Tha) and probably connected to the 500 kV substation at Tha Wung near Bangkok.

Thailand-Myanmar Interconnection: Depending on the power exported from hydropower plants in Myanmar, 230 kV or 500 kV lines will be built toward Northern Thailand.

In summary, the 500 kV transmission lines from Myanmar, Lao PDR and Yunnan hydroelectric resources to Thailand and Viet Nam would form a GMS power network, namely:

- South-eastern Yunnan to northern Viet Nam and central Viet Nam via central Lao PDR to north-eastern Thailand;
- Yunnan through northern Lao PDR to Thailand; and
- Myanmar to north-western Thailand (Chieng Mai area)

A SIMULATION STUDY OF POWER INTERCONNECTION IN SOUTHEAST ASIA

As described in earlier sections, a plan for interconnecting power grids among Southeast Asian economies has long existed. The Heads of ASEAN Power Utilities/Authorities (HAPUA) was established in the early 1980s with the main objective to promote cooperation among the ASEAN state-owned power utility companies. One of HAPUA's cooperation projects is electricity grid interconnection.

For many years, HAPUA's interconnection projects were individual cross-border interconnections between two neighbouring economies, and as mentioned above there are now fourteen cross-border projects in HAPUA's priority list, some of which have been realised. After a declaration of the ASEAN Summit of 1997 which among others stated “ASEAN to have natural gas and power interconnections arrangements by 2020”, that HAPUA began to look at its interconnection plans in a more integrated manner, calling the proposed integrated grid as Trans-ASEAN Power Grid (TAGP).

So far there has been no analytical or simulation studies made on regional power integration. It is against this backdrop that APERC, with expert assistance from Japan's Electric Power Development Co. Ltd. (EPDC) attempted to undertake a simulation of integrated power planning for six of the more developed (and earlier members of ASEAN and APEC) Southeast Asian economies, all of which are APEC members. Viet Nam was not included because of lack of data.

The six economies are Brunei Darussalam, Indonesia, Malaysia, Philippines, Singapore and Viet Nam. In this study, two power-consuming centres (regions, as referred to the report of the studies) of Indonesia are taken into account, Sumatra and Java. Malaysia is also divided into three distinct regions, Peninsular Malaysia, Sabah and Sarawak.

In carrying out the exercise, the EPDC had utilised a quantitative analysis tool it developed called EPDC System Planning Program Reflecting Interconnection and Transmission (ESPRIT). More information and details about the study, the study scenarios, assumptions made, and the results obtained are provided in Appendix A of this report.

AN EVALUATION OF THE STUDY

As mentioned in the previous chapter, there are a number of proposed power interconnection projects in Southeast Asia. However, to date there have been no studies analysing the costs and benefits from cross border linkages between ASEAN member economies. Appendix I contains the results of an initial investigation of the feasibility of power interconnection in the whole Southeast Asia region through a quantitative analysis using the Electric System Planning Program Reflecting Interconnection and Transmission (ESPRIT) developed by the Electric Power Development Company (EPDC). Due to data limitations, the “real” world is simplified significantly in the model. Moreover, sometimes good quality data, particularly for developing economies are not available and sometimes estimates are used. Despite these shortcomings, the simulation produced by the ESPRIT model provides valuable outputs for those interested in planning future power interconnections in this region.

The ESPRIT model considers major objectives of a power development planning (PDP) project taking account of power exchange between systems. Therefore, developing such a model is very helpful for analysing generation expansion planning, including interconnected systems.

The approach is based on the decomposition technique, that is, large scale expansion planning is divided into one master linear problem relating to an optimal power exchange plan, and several sub problems related to smaller scale isolated system expansion planning. Using linear programming the software calculates power exchanges between systems. As the large-scale interconnected system can be decom-

Table 16 GMS interconnection projects

	Existing and Expected Projects	Status and Description
1	Lao PDR – Thailand (Existing)	
	Nam Ngum Hydro Power Plant – EGAT	In operation since 1972. Currently, the generating capacity is around 150MW and about half of the power generated is exported to Thailand through 115kV transmission lines
	Xe Set Hydro Power Plant-EGAT	In operation since 1991 with the capacity of 45 MW. Most of the power generated is exported to Thailand.
	Nam Theun-Hin Boun Hydro Power Plant – Sakon Nakhon Substation of EGAT	In operation since 1998. A double circuit of 230kV transmission line from power plant to the 230kV Sakon Nakhon substation of EGAT via the 230kV Thakhek Intermediate Substation of Lao PDR was built, having a total distance of 160Km
	Houway Ho Hydro Power Plant – Ubon Ratchathani 2 Substation of EGAT	In operation in 1999. A double circuit of 230kV transmission line having a total distance of 230Km from hydro power plant to the 230kV Ubon Ratchathani 2 Substation of EGAT
	Savannakhet – Roi Et (Expected)	The project consists of a double circuit of 500kV transmission line from the Nam Theun 2 Hydropower to the future 500kV Roi Et 2 substation of EGAT via the 500kV Savanakhet Intermediate substation located in Lao PDR, having a total distance of 297km
	Ban Na Bong – Udon Thani 3	Consists of an individual double circuit 230kV transmission line from Nam Ngum 2, 3 hydro plants to Ban Nabong Substation of Lao PDR and an 500kV transmission line from Ban Nabong to Udon Thani 3 substation of Thailand with the distance of 124Km.
	Hong Sa - Mae Moh	The project is a double circuit 500kV line from Hong Sa lignite fired power plant in Lao PDR to the 500kV Mae Moh 3 substation of EGAT with the distance about of 325 Km
	Boloven – Ubol Ratchthani	The interconnection is comprised of a 500kV transmission line from Ubon Ratchthani (Thailand) across Mekong river and goes to 500kV Ban Soc substation (Boloven province-Lao PDR), the total length is about 142Km to the Thai Border.
2	Myanmar - Thailand (Expected)	Four power projects, namely, the Nam Kok, Hutgyi, Tasan hydro power plants and an Kanbauk combined cycle power plant with the total capacity of 5555Mw were included in the initial programme for power export to Thailand in Aprill 1998. A feasibility study of transmission system interconnection between the two economies for supplying power to the Myanmar is being undertaken by EGAT.
3	Yunnan Province – Thailand (Expected)	A 500kV HVDC line with the length of about 1200Km from the Jing Hong hydropower plant in China via Luong Nam Tha province (Lao PDR) is connected to the Tha Wung 500kV substation in Thailand. The pre-feasibility study was completed. So far no progress has been reported due to the transmission line will have to pass through the third county, so it needs very strong cooperation from the concerned economies.
4	Cambodia -Thailand	Details of the project will be studied by the relevant power authorities/ utilities
5	Lao PDR - Viet Nam (Expected)	A double circuit 500kV line with the length about 180Km from the Namtheum 2 500kV station in Laos is connected to the Ha Tinh 500kV station in Central Viet Nam
	Central Lao PDR - Central Viet Nam	A double circuit 500kV line with about 130 Km from the Ban Pan or Ban Soc 500kV station receiving the power from projects in southern Laos to the Playcu 500kV station in Viet Nam.
	Southern Lao PDR - Central Viet Nam	The feasibility studies for both two mentioned projects will be done
6	Cambodia- Viet Nam (Expected)	Interconnection through a 220kV transmission line from southern power system in Viet Nam to PhnomPehn
	Phnompehn – Southern Viet Nam	A feasibility study is being implemented
7	Yunnan Province – Viet Nam (Expected)	Long term project
	Yunnan – Ha Noi	A 500 kV line with the length of 500Km from hydro power plants in southern Yunnan would be connected to the Soc Son 500kV substation in northern Ha Noi.
8	Lao PDR – Cambodia	Long term project – details of the project will be studied by the relevant power authorities/ utilities

Sources: Biyaem, *et al* 1998, Chonglertvanichkul, P., 2000, Jaafar, F., 1999, IE-Viet Nam, 1999, 2000 posed into several smaller scale isolated systems both computation time and model complexity are reduced. Controlling power exchanges and sharing common reserves in the interconnected system can reduce generation capacity and fuel costs. Therefore, the output of this model is a least cost solution for power planning. Also, to ensure that short-term reinforcements are consistent with the long-term network, this case study is performed on different stages to identify step-by-step extensions toward a least cost solution.

Elements that should be included in the cost concept include:

- Capital costs;
- Operation and maintenance costs, including fuel costs;
- Costs of transmission losses;
- Cost of power exchange;
- Environmental costs.

However, the cost of power exchange was not reflected in the ESPRIT model, but hopefully this concern could be dealt with in the future.

In the report, isolated and connected cases were developed for three proposed schemes as mentioned in the appendix. These cases relied on realistic possible prospects in the study period of connecting transmissions between power grids in Southeast Asia. Power plant characteristics and fuel prices of the various plant types as well as other data and assumptions were taken from preliminary APERC estimates on Southeast Asia conditions.

In all proposed schemes, Thailand, Singapore, Peninsular Malaysia and the Philippines would become net power importers, while Sumatra, Indonesia, Sarawak and Sabah of Malaysia would be exporters. In particular, Thailand could become the biggest power importer in the region (around 9,000 MW). Fuel costs were likely to be a major factor in the power import decision-making process.

From the cost-benefits analysis, it has been shown that the total cost for the three interconnected schemes would be cheaper than independent systems. That is logical because the expected load flattens as a result of power exchanges while at the same time system reliability is improved.

The study also examined the feasibility of interconnection projects through results of energy and capacity exchanges, considering utilisation factors and costs of transmission lines. According to the analysis, interconnections between Sarawak, Brunei, Sabah and the Philippines are not practical before 2020 (the study period), while other interconnections in the region are feasible. Transmission lines between Peninsular Malaysia and Singapore, and Peninsular Malaysia and Sarawak are the most financially attractive schemes. It appears that a more realistic time frame for full interconnection in Southeast Asia will be beyond 2020.

COMPLEMENTARITY BETWEEN POWER AND GAS

While those involved in the Trans-ASEAN Gas Pipeline (TAGP) master plan and the Trans-ASEAN Power Grid (TAPG) projects are knowledgeable of each other's plan, the question of competition has not been discussed.

The two infrastructure networks are considered complementary in Southeast Asia. The development of abundant hydropower resources in the Great Sub-Mekong area as well as other indigenous energy reserves such as coal (lignite) contributes to security of energy supply in the region by diversifying fuel supplies. Natural gas supply by pipeline promotes greater gas utilisation and enhances socio-economic development in the region.

ENERGY INFRASTRUCTURE OPTIONS

Analysis made by APERC in 2000 outlined the benefits that could be derived from regionally interconnected power and gas infrastructures [APERC, 2000a and APERC, 2000b]. However, concerns about competition were raised; hence an analysis was carried out to address these issues.

Southeast Asian economies are keen to obtain energy services at internationally competitive prices to maintain or improve competitiveness. One possible hurdle to development of regional energy networks that might assist in this goal, is the cost burden it might place on some individual economies, especially if the benefits for some are not considered to outweigh the costs. To solve this problem, an analysis on a per economy basis, especially for the energy-importing economies was conducted.

Analysis is confined to energy-importing economies, as they will be the ultimate users (the rate-payers) of the proposed schemes. The cost of gas transportation and power wheeling will be added to the purchase price of the natural gas and electricity sold to these economies. Likewise, it is apparent that energy exporters, like Malaysia and Indonesia, will likely support the proposed energy infrastructures, as they will benefit from them through foreign exchange earnings.

THAILAND

Thailand is one of the major energy importing economies in Southeast Asia. Although it produced about 25 million tonnes of oil equivalent (Mtoe) of coal, oil and natural gas in 1998, it had net imports of 31.1 Mtoe out of 57.6 Mtoe of total primary energy supply [EDMC, 2000]. With its limited energy resources and increasing energy demand, Thailand is expected to remain an energy-importing economy in the future.

INDUSTRIAL ENERGY DEMAND

Thailand's future industrial energy demand is expected to grow at a rate of 7.3 percent from 2000 to 2010 [APERC, 1998]. For the sake of this analysis, the growth rates of individual fuels from 2005 to 2010 were applied to project the possible demand in 2015 and 2020. The total energy demand for industry was estimated to increase to 69.4 Mtoe in 2020 (Table 17).

As demand for coal and oil increases, so will the potential for environmental pollution. Coupled with the volatility of petroleum product prices, it is possible that some of the coal and petroleum products could be replaced by natural gas. These probable non-power markets for natural gas were estimated using the manufacturing share of total GDP in areas close to proposed pipeline terminal points, such as: Bangkok, central Thailand (including Ratchaburi and Rayong) and southern Thailand. The probable demand in the commercial and residential sectors was not estimated for simplicity, as costs of distribution infrastructure to these sectors is difficult to obtain. This is due to geographic and demographic factors, requiring more data and detailed analysis.

Since it is highly probable that not all the industrial coal and petroleum consumers will switch to natural gas due to insufficient distribution infrastructure or other technical considerations, a 50 percent probability was assumed. The result of these calculations is shown in Table 18.

The demand for natural gas in the electricity sector was estimated using a least-cost optimisation model wherein the cost of natural gas transportation through pipeline was taken into consideration. This is reflected in the price of natural gas at the power plant sites, which are assumed to be located close to the landing point of the pipeline. The price of natural gas consists of the wellhead and pipeline transmission costs.

Table 17 Projected industrial energy demand in Thailand

	2000	2005	2010	2015*	2020*
			ktoe		
Coal	4,320	6,149	9,155	13,630	20,293
Oil	7,144	8,897	12,033	16,273	22,007
Natural gas	1,025	1,923	3,590	6,701	12,509
Electricity	3,248	4,690	6,849	10,001	14,605
Total	15,647	21,659	31,627	46,605	69,414

Source: APERC, 1998
Notes: * Estimated using the 2005-2010 growth rate.

NATURAL GAS SUPPLY

The 1998 APERC Outlook [APERC, 1998] indicates that Thailand will continue to produce more than 10 Mtoe of natural gas per annum up to 2010, the last year of the outlook. This analysis assumes that production levels will continue to 2020 to examine the possibility of Thailand being able to absorb the natural gas coming from interconnection infrastructure.

In addition to Thailand's indigenous natural gas production, a gas pipeline from Myanmar will bring in 7,261 ktoe per annum of natural gas by 2002. Most of the gas will be used as fuel for CCGT power plants in Ratchaburi [APERC, 2000c]. Likewise, by 2002, natural gas from the Malaysia-Thailand Joint

Table 18 Possible natural gas markets in the industrial and electricity sectors

	2000	2005	2010	2015	2020
			ktoe		
Industrial sector[1]	1,468	2,134	3,178	4,731	7,044
- Coal to be replaced by gas[2]	2,480	3,088	4,177	5,648	7,639
- Oil to be replaced by gas[2]	1,025	1,923	3,590	6,701	12,509
Electricity sector[3]	11,670	16,861	20,591	21,479	25,368
Total	16,643	24,007	31,536	38,560	52,560

Assumptions:
1. The share of energy demand for industry in Bangkok, Central Thailand and Southern Thailand areas is equiv alent to the percentage of manufacturing GVA in these areas to the total manufacturing GVA of Thailand
2. At least 50 percent of the projected coal and petroleum demand in manufacturing in these areas will be replaced by gas.
3. Natural gas requirement for power generation.

Development Area (JDA) will bring in an additional 3,953 ktoe per annum. This will further increase to 6,957 ktoe per annum by 2007. Further, in 2017, Thailand could import 14,700 ktoe per annum from the Natuna Gas field [AEEMTRC, 1996].

Thailand could absorb the natural gas from Natuna as early as 2015 or by 2010 (in smaller quantities that will eventually increase to full capacity by 2015).

ASEAN POWER GRID VS. TRANS-ASEAN NATURAL GAS PIPELINE

Judging from the expected huge demand for natural gas in Thailand by the year 2010 (Table 18), there is no apparent competition between electricity through power grid interconnection with Malaysia and the Great Mekong System (GMS) economies and the proposed natural gas supply from Myanmar, Malaysia and Indonesia (Natuna). Thailand has rapidly growing demand, and by 2020, estimates show that supply from the sources shown in Table 19 will not be enough. Likewise, Thailand will require electricity for intermediate and peak loads that could be supplied from hydro power plants in the GMS system.

Table 19 Natural gas supply for Thailand

	2000	2005	2010	2015	2020
			ktoe		
Indigenous[1]	10,163	10,914	10,683	10,683	10,683
From Myanmar[2]	4,292	7,261	7,261	7,261	7,261
From JDA[2]	0	3,953	6,957	6,957	6,957
From Natuna[3]	0	0	0	14,700	14,700
Total	14,905	22,128	24,902	39,602	39,602

Sources: 1. APERC, 1998, APERC Outlook
2. APERC, 2000b, Natural Gas Development in SEA
3. ASEAN-EC Energy Management Training and Research Centre (AEEMTRC), 1996, Masterplan on Natural Gas Development and Utilisation in the ASEAN Region.

Although calculations show that the total generation and transmission costs of natural gas from Malaysia is cheaper (Table 20) than the electricity produced from imported natural gas from Natuna, the non-power demand for natural gas in Thailand shown in Table 19 will encourage the installation of natural gas pipelines.

POLICY CONSIDERATIONS

There is a need for more detailed study on the planned pipeline infrastructure. As the proposed Natuna pipeline could overlap with the JDA pipeline, a study taking into consideration the two natural gas sources could be necessary. The pipeline from JDA could be enlarged in size to accommodate supply from Natuna in the future.

The growing electricity demand in Thailand requires more baseload capacity to be built in the future. Coal, being the cheapest baseload fuel tends to be the choice in least-cost optimisation simulations. Limiting the capacity additions from coal results in higher total power expansion costs. Giving a premium to natural gas, considering that it is a cleaner fuel might be a good start.

THE PHILIPPINES

The economy is expected to rely on imported energy due to limited domestic reserves. The vigorous efforts of the government to increase energy self-sufficiency can do only so much to alleviate the import-dependence burden. The most promising hydropower and geothermal resources have been developed, leaving limited opportunity for these resources to maintain their share of total supply in the future. While large-scale natural gas production will commence in 2002, growing energy demand will

Table 20 Electricity cost comparisons

	Power grid		Gas pipeline
	Hydro[1]	Natural gas[2]	
Fuel price ($/MMBTU)	-	2.0	2.0
Gas transmission cost ($/MMBTU)	-	-	1.46
Total fuel price	-	2.0	3.46
Generation cost ($/kWh)	0.0336	0.0265	0.367
Electricity transmission cost ($/kWh)	0.0031	0.0072	-
Electricity generation & transmission costs ($/kWh)	0.0367	0.0337	0.0367

Notes: Comparison between imported electricity and electricity generated from imported natural gas.
1 - From Great Mekong System
2. From Malaysia

quickly absorb this new production.

PROJECTED INDUSTRIAL ENERGY DEMAND

For distances below 2,500 kilometres, a natural gas pipeline can still be competitive LNG [AEEMTRC, 1996]. Pipelines, however, must attain economies of scale to reduce costs per unit of gas transported. The minimum economic size of the pipeline should be established in the analysis of natural gas supply.

If the Philippines imports natural gas from Sabah, Malaysia, economic analysis shows that for the pipeline cost to be below US$ 1.5 per million BTU, the gas pipeline needs to have a capacity of 950 billion BTU per day. This will require 24-ktoe per day or 9,000 ktoe per annum of demand.

The problem is finding enough demand to satisfy the required supply volumes. At present, there is virtually no demand for natural gas in the Philippines. It is therefore necessary to look at demand in the power and industrial sectors, now heavy users of coal and petroleum products.

The APERC Outlook [APERC, 1998] projects that industrial energy demand will grow from 6.1 Mtoe in the year 2000 to 9.9 Mtoe in 2010. Using the growth rate from 2005 to 2010 (for simplicity of calculation), the demand will further grow to 13.2 Mtoe in 2015, and to 17.7 Mtoe in 2020 (Table 21).

Part of the industrial coal and oil demand can be replaced by natural gas. In this case, it is assumed there is a possibility that manufacturing industries located near the vicinities of the terminal points of the gas pipeline will shift to natural gas. These areas are in Metro Manila and Region IV. To estimate the industrial demand for natural gas in these areas, the share of manufacturing industries was applied to total energy demand. Assuming that only 50 percent of manufacturing industries will shift to natural gas due to technical considerations, the projected industrial demand is estimated as is shown in Table 22. The table also shows the estimated demand for natural gas in the electricity sector using the least cost optimisation model for power expansion. Demand growth in the electricity sector will require the addition of more than 13,000 MW of additional baseload capacity by 2015. This demand is more than enough to absorb the natural gas supply from the Trans-ASEAN Gas pipeline segment from Borneo to the Philippines.

Due to the absence of an operational gas distribution system in the Philippines, the residential and commercial demands were not estimated.

PROJECTED SOURCES OF NATURAL GAS SUPPLY

Significant indigenous production of natural gas in the Philippines will commence in 2002 with the opening of the Camago-Malampaya field. Gas will be transported through a 500-km pipeline to three

Table 21 Projected industrial energy demand in the Philippines

	2000	2005	2010	2015*	2020*
			ktoe		
Coal	771	995	1,410	1,998	2,831
Oil	4,029	4,560	5,695	7,113	8,883
Natural gas					
Electricity	1,282	1,924	2,804	4,087	5,957
Total	6,082	7,479	9,909	13,198	17,671

Source: APERC, 1998.
* Estimated using the 2005-2010 growth rate.

power plants with a total capacity of 2,700 MW. From then on however, no additional gas reserves have been confirmed, so natural gas production is expected to remain constant to 2020.

With increasing demand, natural gas imports are required as early as 2005. However, since the non-power demand is possible only if supply is available and the quantity of demand is not enough to encourage natural gas imports in either liquefied or gaseous forms, only the power sector is expected to import natural gas.

The above analysis shows that the Philippines can absorb natural gas supply from Borneo. It should however be noted that the result assumes that the wellhead price of natural gas from Borneo will not be more than US$ 2.0 per million cubic feet (mcf) and transportation cost of not more than US$ 1.40 per mcf. Any increase in these cost assumptions will significantly change the economics of pipeline supply.

The environmental benefits of gas were not considered in the analysis. It is however recognized that GHG emissions can be significantly reduced owing to the lower carbon content of gas coupled with the higher efficiency of the CCGT. A more detailed analysis will require additional data and information on carbon emissions trading. All this work can do is to suggest that the role of natural gas in climate change mitigation strategies should be given due consideration.

ASEAN POWER GRID VS. TRANS-ASEAN NATURAL GAS PIPELINE

Table 22 Possible natural gas markets

	2000	2005	2010	2015	2020
			ktoe		
Industrial sector[1]					
- Coal replaced by gas[2]	0	145	206	292	414
- Oil replaced by gas[2]	0	666	832	1,040	1,298
Electricity sector[3]	0	3,324	6,584	14,740	21,159
Total	0	4,136	7,622	16,072	22,871

Assumptions:
1. The share of energy demand for industry in Metro Manila and Region IV is equivalent to the ratio of the manufacturing GVA of these areas to the total manufacturing GVA of the Philippines.
2. At least 50 percent of the projected coal and petroleum demand in manufacturing in these areas will be replaced by gas.
3. Natural gas requirement for power generation with 50 percent of coal generation will be replaced by gas starting 2010.

Being an energy-importer, the Philippines has a number of options for fuel procurement. First is the current importation of coal, crude oil and petroleum products using cargo vessels and oil tankers. With the expected growth in energy demand, various options need to be considered to diversify energy supply. Too much dependence on one option would not be beneficial in the long run, especially during large fluctuations in crude oil prices.

Table 23 Projected sources of natural gas supply in the Philippines

	2000	2005	2010	2015	2020
			ktoe		
Indigenous	-	3,500	3,500	3,500	3,500
From TAGP	-	-	-	14,700	14,700
Total	-	3,500	3,500	18,200	18,200

Sources: AEEMTRC, 1996; Philippine DOE, 1999

Other options that need to be considered are LNG imports, natural gas imports through long-distance pipelines and electricity imports. The high cost of the LNG import option and the relatively short distance of the Philippines from gas reserves in the ASEAN region may make pipeline imports more attractive than LNG.

Because an electricity interconnection could discourage gas imports, an analysis of the cost implications of the two infrastructure options was carried out to find out which has an advantage in terms of costs.

For this analysis, it is assumed that the power interconnection line will come from Sabah, with the supply plants located in Sabah. No flow of electricity from the Philippines to Sabah is assumed in order to maximise the utilisation of the interconnection line to attain economies of scale and reduce the wheeling price of electricity.

For a natural gas pipeline, the capacity was assumed to be of a size needed to obtain the minimum transmission costs per unit volume of natural gas. The assumed capacity was 950 billion BTU per day or equivalent to 950 million cubic feet per day. The resulting transmission cost per million BTU (MMBTU) is US$ 1.46. Assuming that the wellhead price of gas is US$ 2.0, the landed cost of natural gas will be US$3 .46 per MMBTU. Using this fuel price and the assumed cost of building an advanced combined-cycle power plant at a certain discount rate, the generation cost per kWh of electricity was calculated to be US 3.67 cents per kWh (see Table 24).

For the power grid interconnection option, it is assumed that the fuel price is equal to US$ 2.0 per MMBTU, which is equal to the wellhead price of natural gas. Using this fuel price and the assumed cost of building a CCGT as mentioned above, the resulting electricity generation cost was estimated to be US 2.65 cents per kWh. The cost of transporting this electricity to the Philippines was estimated using assumed costs of building an interconnection line. An economic size was also estimated to benefit from economies of scale. The resulting transmission price per kWh is US 1.36 cents per kWh. Adding the generation cost, the total generation and transmission price is US 4.01 cents per kWh, higher by US 0.34 cents per kWh. One could conclude that it will be better for the Philippines to opt for a pipeline interconnection than a power grid interconnection.

SINGAPORE

Singapore imports almost 100 percent of its energy needs. Despite of this, Singapore is a major exporter of petroleum products because of its relatively big energy transformation industry. In 1998, Singapore consumed 21.0 Mtoe of primary energy. The mix of fuel consists of petroleum and natural gas.

Table 24 Electricity cost comparisons

	Power grid		Gas pipeline
	Coal	Natural gas	
Fuel price ($/MMBTU)	0.3252	2.0	2.0
Gas transmission cost ($/MMBTU)	-	-	1.46
Total fuel price	0.3252	2.0	3.46
Generation cost (US$/kWh)	0.0284	0.0265	0.367
Electricity transmission cost (US$/kWh)	0.0136	0.0136	-
Electricity generation & transmission costs ($/kWh)	0.042	0.0401	0.0367

Notes: Comparison between imported electricity and electricity generated from TAGP gas.

As the economy is not endowed with energy resources, Singapore will purchase its future energy supply from overseas. The most probable sources of energy will be Malaysia and Indonesia, both of which are energy exporting economies. With the penetration of natural gas and the existence of distribution facilities, natural gas share in the primary energy mix is expected to increase.

The projected primary energy demand in Singapore is presented in Table 25. Due to the volatility of crude oil prices in the world market, natural gas may replace oil as the major fuel for electricity generation. Results from least-cost optimisation show that natural gas demand in Singapore will increase to 8.8 Mtoe in 2015 and to 13.5 Mtoe by 2020. This demand could easily absorb the natural gas supply from Natuna that was projected in the master plan for natural gas development and utilisation in the ASEAN region prepared by AEEMTRC in 1996 (Table 26). Hence, it is likely that Singapore will highly favour interconnecting to the planned ASEAN regional natural gas pipeline.

As Singapore's power grid system is currently interconnected with that of Malaysia, the possibility that the current mutual backup arrangement could be changed to an energy importation arrangement in the future cannot be discounted. There is therefore a possibility that the two energy infrastructures would compete with each other. However, Singapore would more likely favour the natural gas pipeline option due to the energy requirements of its industries.

VIET NAM

Viet Nam was a net energy exporter in 1998. It exported 14.2 Mtoe of crude oil and coal and imported 6.6 Mtoe of petroleum products [EDMC, 2000]. It has large energy reserves. Proven oil reserves are estimated to be 390 Mt, natural gas at 627 billion cubic meters (BCM) and coal at 3,300 Mt [APERC, 2000d].

Table 25 Energy demand forecast for Singapore

	2000	2005	2010	2015**	2020**
			ktoe		
Oil	12,987	13,032	13,119	13,207	13,295
Industry*	2,420	3,108	4,146	5,532	7,380
Other Sectors	10,567	9,924	8,973	7,675	5,915
Natural Gas	1,659	2,857	4,593	8,755	13,484
Industry*	29	131	311	738	1,749
Electricity Generation***	1,630	2,726	4,282	8,018	11,735
Total	14,645	15,889	17,711	21,962	26,779

Notes: *Source: APERC, 1998.
** Oil and natural gas demand for industries were estimated using the 2005-2010 growth rate.
*** Estimated using APERC Least-Cost Power Expansion Optimisation Model.

Natural gas demand in Viet Nam is projected to increase from 1.08 ktoe in 2000 to 14.13 Mtoe in 2020 [Institute of Energy: Viet Nam, 2000]. Based on simulations conducted in this study, this projected natural gas demand could only be for electricity generation. Installation of distribution pipelines will further increase this demand projection with the inclusion of industries and possibly, transport consumption.

With huge natural gas reserves, Viet Nam could export gas to Thailand or China. Hence, it is possible that Viet Nam would be interested in connecting to the TAGP as an energy exporter.

Table 26 Possible supplies of natural gas for Singapore

Sources	2000	2005	2010	2015	2020
			ktoe		
From current sources	1,659	2,857	4,593	4,593	4,593
From Natuna*	-	-	-	5,762	5,762
Total	1,659	2,857	4,593	10,355	10,355

Source: AEEMTRC, 1996.

CONCLUSIONS

The rapid energy demand growth in the region will require the construction of energy transmission infrastructure. In Thailand and Singapore, the power interconnection and natural gas pipeline infrastructure will not compete with each other as demand in these economies are big enough to absorb the supply from these energy sources. The distances of these economies to exporting economies do not prevent the development of the proposed infrastructure. For the Philippines, the distance from exporting economies and the intervening seas renders the cost of interconnection high. Simulations made to calculate the cost of transporting natural gas and electricity show that natural gas pipeline interconnection is the better option.

There is a need to harmonise the infrastructure development plans of the economies involved in order facilitate future interconnections. Interconnections should allow for longer-term expansion in demand to reduce the overall costs of developing the regional system.

Although the infrastructures assumed in this study will not pass through disputed territories, it is imperative that economies involved settle territorial disputes so that all energy supply options could be considered.

CHAPTER 7

OTHER APEC NATURAL GAS PIPELINE PROJECTS

PAPUA NEW GUINEA - AUSTRALIA

NATURAL GAS RESOURCES IN PAPUA NEW GUINEA

Papua New Guinea (PNG) is located north of Australia and shares one half of the island with Indonesia (Irian Jaya - now West Papua). Both Australia and PNG are close to Indonesia, and hence to Southeast Asia. Australia in particular is an important energy exporter to both Southeast and Northeast Asia, supplying natural gas, coal and oil.

Oil seeps were first discovered in PNG in 1911, near the mouth of the Vailala River, 250 km north-west of Port Moresby, the capital city of PNG. These encouraged the Australian Commonwealth Government to search for oil in the area, a major challenge given the complex geology and limited access.

The Anglo-Iranian Oil Company and Vacuum Oil Company joined Oil Search Ltd in 1938 and by 1957 they had spent more than 25 million pounds sterling in exploration activities. The Shell Oil Company temporarily joined before World War 2 halted all operations. Renewed exploration after the war culminated in the first discoveries in the mid 1950s. In 1956 a gas blow-out at Kuru brought in the celebrated well control expert Red Adair, and was said to have flowed gas at rates estimated between 50 and 100 million cubic feet per day from tertiary limestone. In 1958, testing of the large Barikewa anti-cline yielded dry gas from a Mesozoic sand reservoir. While almost 40 years later, this field lies unexploited, with reserves conservatively estimated at 100 billion cubic feet of recoverable gas. This early petroleum discovery indicated that PNG could become a gas-producing economy.

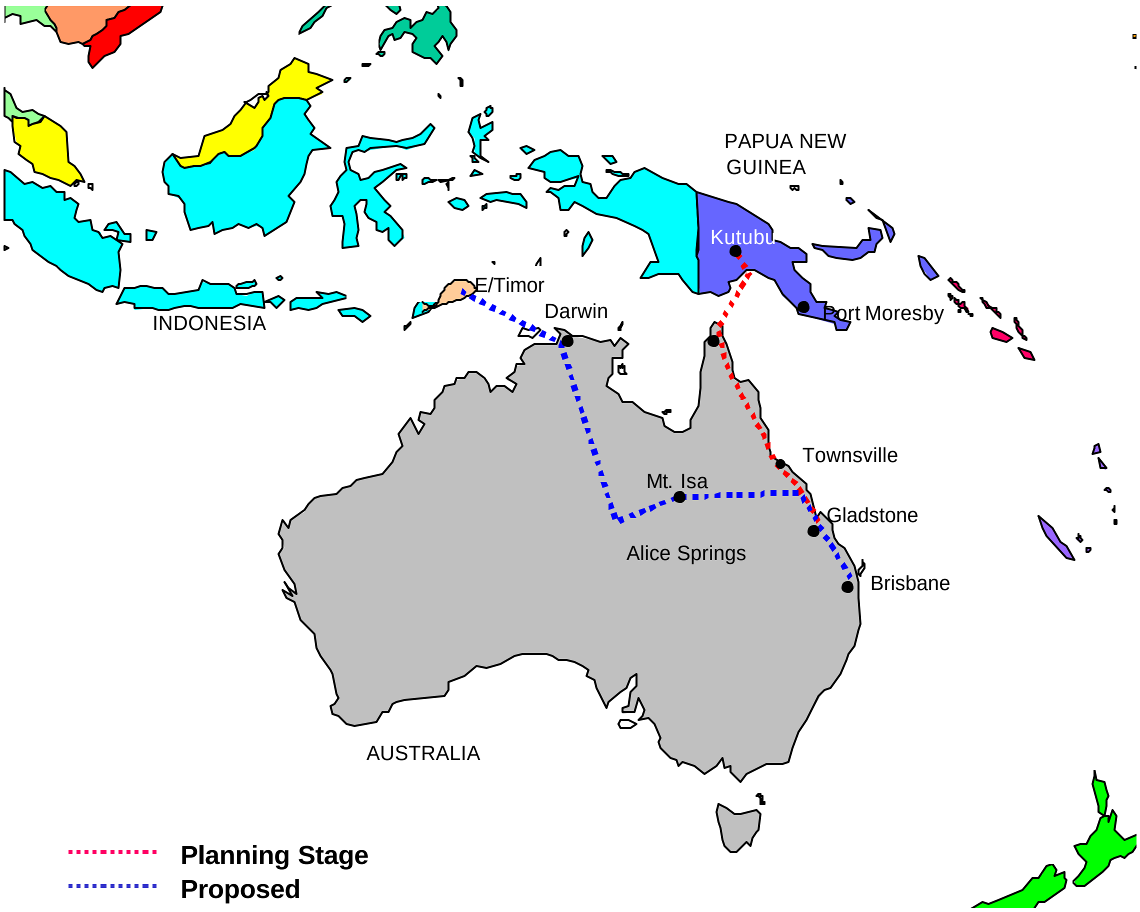
Renewed efforts in the 1960s and 1970s identified further gas potential as discoveries were made, the largest being at Pasca in the Gulf of Papua. Unfortunately, a blowout in a delineation well on the Pasca structure was never brought under control. However, exploration work progressed farther into the Papuan fold-thrust belt. Buoyed by the discovery of light sweet crude in the Iagifu anticline in 1986, exploration expenses reached a peak of US$ 250 million. Some 13 trillion cubic feet of gas reserves were identified at a dozen wells. Not only have commercial quantities of oil been discovered, large volumes of gas are known to exist.

Some 258 exploratory wells had been drilled in PNG by the end of 1995. In the past 14 years, recoverable hydrocarbons have been found in one of every seven wells drilled. With such a low drilling density, high success rate, and with only the more overt play-types drilled, it is expected that many more fields might exist. At this juncture, it is estimated that probable and possible recoverable resource assessment put current natural gas availability at 14 TCF.

The Kutubu oil fields (see Figure 17) were put into production in June 1992 and to date have produced more than 159 million barrels of oil. The Kutubu crude has found a niche in the Asia - Pacific crude markets: almost 80 percent of production goes to Australia and the balance to other destinations in the region. Production is being held at or around 100,000 barrels per day, as gas breakthrough and field gas handling capacity limits are balanced against new production from new development wells. Current plans are for two small size oil refineries to be built (in Port Moresby and Lae) to process some of the oil into petroleum products.

The Kutubu oil fields are in effect large gas fields with oil rims. Estimated ultimate recoverable reserves are 270 million barrels of oil and 2 TCF of gas. As oil production approaches one-quarter of the original oil in place, schemes are being contemplated for gas production. Currently, over 150 MCFD are re-injected into the gas caps above the oil to assist in reservoir pressure maintenance. It is hoped that the same compression system could quite easily be used to dispatch the gas down a gas transmission pipeline and to the market when needed.

Figure 17 Proposed pipeline routes (PNG & East Timor to Australia)



A possible market for PNG gas is Queensland, Australia, where natural gas is being seriously considered as fuel for power generation and for smelting works. Furthermore, such a project could enhance Australia's greenhouse gas emission reduction plans - reducing emissions from current levels of 494 MtC to 455 MtC in 2010 [APERC/ADEME, 2000]. This is encouraging news in terms of mitigating global climate change. (Discussion of this issue can be found in Chapter 2 of the 2000 APERC report Natural Gas Infrastructure Development in Southeast Asia).

Approximately 60 kilometres to the northwest of the Kutubu fields lies the Hides gas field, discovered by BP in 1987. The field was put into small-scale production in 1991 and it currently produces 15 million cubic feet per day from a conservatively estimated recoverable reserve of 4 TCF. The gas is supplied to the Porgera Goldmine for electrical power generation. Such niche use of local energy to power the mine operations contributed greatly to the mine's first year of productions. The Hides field could provide 6 trillion cubic feet of gas.

In 1997, PNG's net primary energy supply was 875 ktoe. This total was composed of 95.3 percent light crude oil/ petroleum products and 4.8 percent hydro/other fuels. PNG exports some oil to other economies. Other oil and gas exploration activities are continuing, with an annual budget around US$ 20 million. Most recently (September 2000), the government announced the approval of a Petroleum Development Licence for Moran Oil to begin production of 13,000 bbl/day by the end of the year 2000 to supplement the Kutubu project [PNG Post Courier, 2000a].

NATURAL GAS DEVELOPMENTS

It is only recently, in the mid-late 1990s, that increasing demand for energy in Queensland, Australia has resulted in interest in the PNG gas project.

The more than 14 TCF of gas in PNG is considered sufficient for development and export to prospective buyers in Queensland. Market analysis has confirmed the bulk of demand in Queensland for electricity generation and other uses. Queensland is one of the few Australian states where expanding energy demand is not matched by existing supplies of clean alternatives. A long negotiation process commenced before the agreements were signed by both economies. The agreed gas price was AUS$ 2.61/GJ. PNG's conditions are set within the guidelines of the Oil & Gas Act 1998.

Queensland could opt to continue using coal, or import energy from other states, but due to Australia's position on greenhouse gas emissions, it has opted for natural gas. Due to this reason, export of PNG natural gas to Australia could become a reality. The supply quota per year will be around 11.2 BCM (0.4 TCF) for 30 years.

Some important data for the PNG - Australia Natural Gas Pipeline project are as follows:

- The gas reserves are confirmed at 14 TCF.
- The overall length of the pipeline, both sea and over land is 2,400 kilometres.
- The price of gas as agreed by negotiations is now set at AUS$ 2.61/GJ [PNG Department of Petroleum and Energy, 2001].
- Electricity demand in Queensland is projected to grow from 36,600 GWh in 1998 to 57,400 GWh by 2012.
- The overall cost of the project is estimated to be US$5 billion.

CHOICE OF ENERGY INFRASTRUCTURE

There are two options for the long-distance transportation of energy from Papua New Guinea to Queensland. One option is to transport natural gas directly through gas pipeline, and the other option is to convert gas to electricity in Papua New Guinea and transport the secondary energy over power transmission lines.

The key consideration on the choice of energy carrier is infrastructure economics and technological challenges. Although pipeline interconnection may be much more costly, it is not possible to transmit electricity over the same length of transmission line without adding additional equipment to sustain the required voltage at the consuming end. Transportation losses for both natural gas and electricity transmission over such a long distance will have to be taken into account and critically compared between the two.

The stakeholders are now busy raising funds as the project moves into the phase of front end engineering design [PNG Post Courier, 2000a].

The expected benefits include enhanced energy security, creation of jobs, and the reduction of GHG emissions.

OTHER NATURAL GAS PIPELINE CONCEPTS

There have been suggestions that another gas pipeline project is feasible, from East Timor to the same market in Australia. From preliminary talks, this pipeline could go from East Timor via Darwin, Mt. Isa, Townsville and down the east coast to Brisbane. (see Figure 17). The East Timor - Australia pipeline idea is still in a very early conceptual stage, and no confirmed figures have yet been seen as to the proven reserves in East Timor to justify such long distance pipeline infrastructure.

CHAPTER 8

CONCLUSIONS AND POLICY IMPLICATIONS

GENERAL CONCLUSION

Energy infrastructure networks can enhance the security, flexibility and quality of energy supply in the APEC region. They also act as an impetus to economic growth and encourage cooperation.

With natural gas and other energy resources in abundance in parts of Northeast and Southeast Asia, there are good opportunities for regional energy trade.

NORTHEAST ASIA

No cross-border energy infrastructure yet exists in Northeast Asia. However, the potential is good for Russia to develop its natural gas and hydropower resources in Irkutsk and Sakhalin, and export the energy using appropriate infrastructure linkages to China and even to Korea and Japan.

With Irkutsk having rich natural gas resources, and Beijing being a big demand centre, it appears that the Irkutsk - Beijing pipeline project is viable. Further, if high transmission volumes are required to justify the long distances involved, the pipeline could be extended to other cities in China, or to Korea and Japan. Along the eastern corridor, the Sakhalin-China and Sakhalin-Japan proposals offer other options.

The huge infrastructure costs arising from the long distances between the energy resources and markets is the main barrier to gas pipeline and power interconnections. Northeast Asia also lacks a cohesive intra-regional energy or economic cooperation framework (similar to ASEAN) between the respective economies.

Respective governments can play a decisive role in facilitating the development of natural gas and electric grid infrastructure and related markets by creating business environments that are more stable, transparent, predictable and competitive. Like most high-cost energy infrastructure projects all over the world, the financing and development of the projects would have to involve the private sector, with assistance from state-owned energy companies.

SOUTHEAST ASIA

Apart from Singapore, all Southeast Asian economies are well endowed with energy resources. Some economies have insufficient resources to meet growing domestic demand, and need to import energy. The relatively close distances between energy resources and demand centres is one factor that helps in the development of cross-border infrastructure links. The cost of the infrastructure per kilometre is the single most important factor in determining the viability of each project.

Southeast Asia has two sub-regions where energy exporters and energy importers are in close proximity, so the economics of energy interconnection are often attractive. One sub-region is the Greater Mekong Sub-basin (Cambodia, Yunan in South China, Laos PDR, Myanmar, Thailand and Viet Nam. The other is Borneo Island, which includes Brunei Darussalam, Indonesia (Kalimantan) and East Malaysia (Sabah and Sarawak).

Interconnections within the first sub-region are more developed, especially in the case of natural gas interconnections, with three cross-border pipelines now in place and operating (Myanmar-Thailand, Peninsular Malaysia-Singapore, and West Natuna-Singapore). These cross-border pipelines are not interconnected to each other, but by their links to existing and established local networks, most of this sub-region (if not all) could be interconnected in the future. Peninsular Malaysia, and to some extent Thailand, have good existing domestic pipeline networks. The existing domestic PGU network already established in Peninsular Malaysia since 1992 can in the future be linked not only to the MT-JDA, which is being planned, but possibly to gas from Yadana if Thailand expands its domestic gas network. Wider interconnections could lead to and facilitate open gas markets in the region in the future.

Power interconnections, too, are more concentrated in this part of Southeast Asia. Three interconnections are in existence, and out of twelve other cross-border projects in the pipeline, eight are in this sub-region, including the existing three. But the full benefits of the three existing interconnections are yet to be developed.

Particularly for Southeast Asia, political support and vision provided by the ASEAN Summit Meetings and ASEAN Energy Meetings have played a key role in the development of infrastructure projects. Directions and declarations spelled out by these meetings are further deliberated by senior energy officials meetings and meetings of Southeast Asia's state-owned oil and gas companies (ASEAN Council on Petroleum - ASCOPE) and electricity utility companies (Head of ASEAN Power Utility/Authority - HAPUA).

ASIA-PACIFIC INTERCONNECTIONS

In the long term, prospects are good that many of the economies in the Asia-Pacific region may have interconnected energy infrastructure - in particular a gas network. The Trans-ASEAN Gas Pipeline (TAGP), long an aspiration to in Southeast Asia is being realised as a step-by-step development of cross-border pipelines. As mentioned in the previous chapter, Australia and Papua New Guinea are also proposing to develop a pipeline link with gas flowing from Papua New Guinea to Australia.

In Northeast Asia, one or more pipeline linkages may eventually be realised with Russia transporting gas to China or Japan. The Sakhalin-1 project appears to be receiving more serious consideration than other proposals.

ASCOPE is also planning to look into the possibility of a natural gas pipeline from the Natuna East reserves, which is Southeast Asia's biggest gas reserve, to China with the possibility of exports to include Korea and Japan.

POLICY IMPLICATIONS

Summarised below are the potential barriers to overcome or agendas that have to be resolved in order to realise the benefits of trans-border gas pipeline and power grid interconnection.

1) *Geopolitical issues need to be resolved by all parties*

Geopolitical differences and conflicts are a major regional impediment to cross-border energy infrastructure development. Areas with known hydrocarbon and other energy resources that cannot be developed because of territorial disputes only deprive the region of additional energy supply security. An obvious solution is for economies to jointly develop those resources and share the benefits that could be derived from them.

2) Laws and regulations of each economy have to be harmonised with regard to energy trade, pricing, and contracts

Transparency of rules and regulations must be established and maintained in any joint project. Where rules and regulations with regards to energy trade and pricing are different, they must first be harmonised. Where subsidies are still required for social reasons, they need to be transparent and explicitly targeted.

3) A transmission protocol should be established, as well as open access rules

This is an important aspect of pipeline or power grid management to ensure the security and reliability of the energy commodity (either gas or electricity) delivered.

When a pipeline or transmission line has to pass through one or more economies, transit rights and transit fees have to be clearly settled to avoid future conflicts that could threaten the flow of energy. No international agreements, such as the European Energy Charter, exist as yet in the Asia-Pacific region - negotiations should be considered under which gas or electricity transit can be codified.

4) Transparent tariff systems for production, transmission and distribution should be developed

With energy infrastructure investments now expected to be driven by the private sector, a transparent tariff system for production, transmission and distribution is needed to assist investors to estimate risks, and find investment partners.

5) Mutual benefits from interconnection have to be identified and commitments by all economies secured

All parties involved in infrastructure projects need to have a clear understanding of the benefits to encourage full support.

Endnotes

1 In the APERC Outlook forecast, interconnections were assumed to be limited. The projected electricity trade is based on interconnections currently existing in the APEC region. These account for 1.4 percent (an increase from 42 TWh in 1995 to 79 TWh in 2010) of total APEC electricity demand by 2010, including the exchange of electricity between the US and Canada; US and Mexico; China and Hong Kong China; and Thailand with neighbouring economies.

2 Brunei Darussalam has a population of just over 300,000. In spite of its small area (5,765 sq. km), the economy has three natural gas-fired power stations, each with separate small networks and own reserve units.

3 The 16,089 MW includes only the total installed capacity of the main grid. Small island grids and off-grid systems are excluded.

4 Loops are parallel lines build between specific points in long-distance pipelines to increase the flow capacity, when increasing the number of compressor units is no longer economic.

5 The duration of a storage service is the booked capacity divided by the booked deliverability. If the space is full of gas, the duration is the number of days it takes to empty the space by withdrawing at maximum rate.

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APPENDIX

SUMMARY OF EPDC REPORT ON POWER GRID INTERCONNECTION

BACKGROUND

This appendix provides some indication of the feasibility of power interconnection throughout the whole of the Southeast Asia region. This was achieved through a quantitative analysis using a model called the Electric System Planning Program Reflecting Interconnection and Transmission (ESPRIT), developed by the Electric Power Development Company Ltd of Japan (EPDC). Since time and data were limited, the study covers only six ASEAN-APEC member economies: Brunei Darussalam, Malaysia, Indonesia, the Philippines, Singapore and Thailand.

METHODOLOGY

POWER DEVELOPMENT PLANNING (NON-INTERCONNECTED)

From the business-as-usual demand forecast projected in the *1998 APERC Demand and Supply Outlook* (B98), the peak demand in each economy from 1999 until 2020 was calculated.

From the results of this calculation, a power development plan for each economy was made, assuming a reserve margin of 15-25 percent - based on the power development plans for each economy.

POWER DEVELOPMENT PLANNING (INTERCONNECTED SYSTEM)

Assuming that the reserve margin can be reduced by 5 percent when the system is fully interconnected, the power flow was calculated using the ESPRIT model based on the interconnection schemes for each economy. The optimum power development plan for each power system was then established.

STUDY OF INTERCONNECTION METHOD AND CAPACITY

The appropriate interconnection system for each economy was determined by referring to CIGRE (Conference Internationale des Grands Reseaux Electriques) papers and EPDC research data, and further from the result obtained with ESPRIT. On the basis that interconnection capacity between each economy is not constrained, interconnection capacity was determined, thus allowing calculation of the approximate costs of interconnection facilities.

FEASIBILITY STUDY OF EACH INTERCONNECTION SCHEME

Economic efficiencies for non-interconnected and interconnected systems were proposed by APERC, and evaluated to determine the feasibility of interconnection plans.

ENVIRONMENTAL IMPACTS

Power generation CO_2 emissions were calculated using the ESPRIT program for both non-interconnected and interconnected systems.

OUTLINE OF ESPRIT MODEL

The ESPRIT model calculates the optimum power development plan for an interconnection system.

Typical power development models include the Wien Automatic System Planning Package (WASP) developed by the International Atomic Energy Agency (IAEA), the Electric Generation Expansion Analysis System (EGEAS) developed by the Electric Power Research Institute (EPRI) and the Westinghouse Interactive Generation Planning model (WIGPLAN) developed by Westinghouse Corp. All of these modelling tools were developed assuming a single bus model in which power and load are ideally connected without restricting transmission capacity, and thus are difficult to apply to any power system in which there are two or more networks. This makes these tools unsuited to modelling an interconnected system, where there are interconnection capacity restrictions between each power grid.

ESPRIT is a model that divides the problem of a large-scale and complex interconnected system into individual problems for each system, and those of the power exchange plan between systems, thereby obtaining the optimum solution by solving these problems iteratively.

The impacts of transmission cost on power exchange are not included in the ESPRIT optimisation model. This weakness in the analysis would need to be taken into consideration when considering the actual economics of an interconnected system. This is the important aspect of the model for future improvement.

The main features of ESPRIT are as follows:

1. Power plans for a large-scale and complex interconnected system are divided into individual problems for each system and those dealing with power exchanges between systems, thus simplifying the calculations.

2. The model takes into account the specified level of reliability and can develop an optimum power plan to minimise cost.

3. The model can calculate the optimum power exchange (improvement in reliability and economical efficiency) taking into consideration the capacity of interconnection lines, by using time-series daily load curves in order to take into account load variations between each system.

4. In order to simulate the operational plan, load duration curves are used to simulate probability demand, taking into consideration the failure rate for each power plant.

5. CO_2 emissions can be calculated.

DATA INPUT

The main input data are as follows:

1) Daily load curves in time series.

2) Capacity of interconnection lines.

3) Characteristic data on existing and new power stations.

4) Monthly supply power from each hydropower station.

5) LOLP standard.

6) Unit fuel cost and unit capital.

ESPRIT OUTPUT

The main outputs are as follows:

1) Scenario of optimum power plan.

2) Power station operation plan.

3) Amount of CO_2 emissions.

4) Distribution of 24-hour power flow.

5) Capital, fuel cost and unit generation cost.

STUDY ZONES

Analysis was made to the following 6 economies (9 zones)

1) Brunei Darussalam

2) Indonesia (Sumatra)

3) Indonesia (Java)

4) Malaysia (Peninsular)

5) Malaysia (Sarawak)

6) Malaysia (Sabah)

7) The Philippines

8) Singapore

9) Thailand

SCENARIOS

Two scenarios were considered (1) power interconnection, and (2) no interconnection between each economy.

For the non-interconnected scenario, only the existing interconnection between Thailand and Peninsular Malaysia was taken into account. This means that 300 MW in 1999 and 600 MW from 2001 until 2020 are assumed interconnected between Thailand and Peninsular Malaysia. In addition, it was assumed that between Peninsular Malaysia and Singapore there are interconnection lines but no power exchanges, as power is interconnected in case of emergency (Table A 1).

For the power interconnection case, the three scenarios shown in Table A 2 to Table A 4 are assumed.

The interconnection scenarios assumed for each economy are shown in Figure A 2, Figure A 3, and Figure A 4. (It is assumed that the interconnections between Thailand and Peninsular Malaysia and between Peninsular Malaysia and Singapore will be further strengthened in 2014 and are treated in the same way as any other interconnection after 2014.)

Table A 1 Isolated Case

Interconnection	2001-2010	2011-2014	2015-2020
Thailand – P. Malaysia	Interconnected	Interconnected	Interconnected
P. Malaysia – Singapore	Interconnected	Interconnected	Interconnected
Sumatra – Java	No	No	No
P. Malaysia – Sumatra	No	No	No
P. Malaysia – Sarawak	No	No	No
Sarawak – Brunei Ds – Sabah	No	No	No
Sabah – Philippines	No	No	No

Source: EPDC, 2000:

Table A 2 Connected Case 1 (Scheme 1)

Interconnection	2001-2010	2011-2014	2015-2020
Thailand – P. Malaysia	Interconnected	Interconnected	Interconnected (Strengthened)
P.Malaysia – Singapore	Interconnected	Interconnected	Interconnected (Strengthened)
Sumatra – Java	No	Interconnected	Interconnected
P. Malaysia – Sumatra	No	No	Interconnected
P. Malaysia – Sarawak	No	No	Interconnected
Sarawak – Brunei Ds – Sabah	No	No	Interconnected
Sabah – Philippines	No	No	No

Source: EPDC, 2000

Table A 3 Connected Case 2 (Scheme 2)

Interconnection	2001-2010	2011-2014	2015-2020
Thailand – P. Malaysia	Interconnected	Interconnected	Interconnected (Strengthened)
P. Malaysia – Singapore	Interconnected	Interconnected	Interconnected (Strengthened)
Sumatra – Java	No	Interconnected	Interconnected
P. Malaysia – Sumatra	No	No	Interconnected
P. Malaysia – Sarawak	No	No	Interconnected
Sarawak – Brunei Ds – Sabah	No	No	No

Source: EPDC, 2000

Table A 4 Connected Case 3 (Scheme 3)

Interconnection	2001-2010	2011-2014	2015-2020
Thailand – P. Malaysia	Interconnected	Interconnected	Interconnected (Strengthened)
P. Malaysia – Singapore	Interconnected	Interconnected	Interconnected (Strengthened)
Sumatra – Java	No	Interconnected	Interconnected
P. Malaysia – Sumatra	No	No	Interconnected
P. Malaysia – Sarawak	No	No	Interconnected
Sarawak – Brunei Ds – Sabah	No	No	Interconnected
Sabah – Philippines	No	No	Interconnected

Source: EPDC, 2000

DEMAND FORECAST AND POWER DEVELOPMENT PLAN

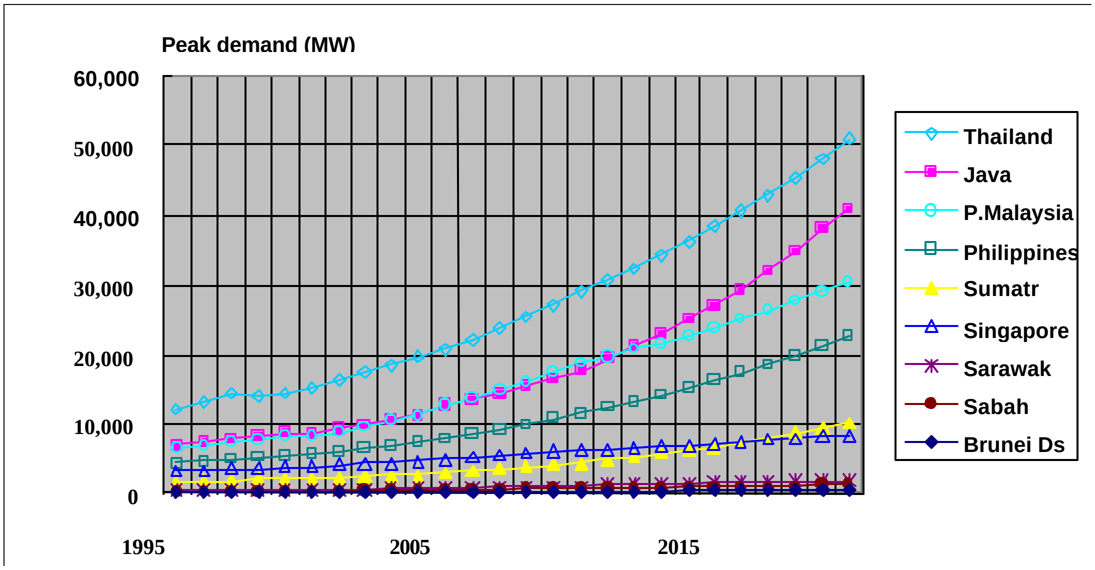
Analysis was based on the B98 demand forecast in the *1998 APERC Demand and Supply Outlook* (see Figure A 1).

A power development plan was developed assuming that the appropriate reserve margin can be assured to cover the above demand forecast. For each region where the peak power restriction effect is achieved by the interconnection this time, the calculation was performed according to the following reserve margin.

In addition, new generation capacity is assumed to be thermal (see Table A 6). The hydropower capacity is fixed for the purposes of the simulation.

Based on demand estimates for each economy, a power development plan to 2020 was developed (for the non-interconnected case). The reserve margin for each economy without interconnection was set at

Figure A 1 Demand forecast for B98 Scenario



Source: EPDC, 2000

Table A 5 Estimated reserve margins (for selected regions)

	Isolated case		Connected case	
Thailand	25%	20%	25%	15%
	(1999-2010)	(2011-2020)	(1999-2011)	(2011-2020)
Other Economies Regions	25%		25%	20%
	(1999-2020)		(1999-2014)	(2015-2020)

Source: EPDC, 2000

25 percent of peak demand. The Thailand-Peninsular Malaysia interconnection (assumed to have 600 MW in place by 2014) is considered small by comparison with the system scale, so the reserve margin was set slightly below 25 percent.)

With an interconnected system, the reserve margin becomes smaller and also power development plans can be stretched out to a longer time frame. The reserve margin was re-set to 15 - 20 percent for the interconnected simulations. It is assumed that the load profile in each economy remains unchanged after interconnection.

The reserve margin reduction with the interconnected system does not work out quite as easily in reality compared with the model for the following reasons:

1) In an economy with small system capacity, one new power plant will have a large influence on the overall system, so the reserve margin cannot be finely adjusted. (Brunei Darussalam, Sabah and Sumatra).

2) If a power exchange is not made at times of peak demand, there is little room to reduce the power development plan. (Java and Singapore).

Table A 6 Estimated fuel ratios for APEC economies

Economy	Fuel ratio of new facilities 1999-2010	2011-2020	Capacity of new plant (MW/unit)
Brunei Ds	Domestic gas	Domestic gas	50
Sumatra	Domestic gas: Domestic coal = 1:1	Domestic gas: Domestic coal = 1:2	200
Java	Domestic gas: Domestic coal = 1:1	Domestic gas: Domestic coal = 1:2	500
P. Malaysia	Domestic gas: Imported coal = 8:1	Domestic gas: Imported coal = 6:1	500
Sarawak	Domestic gas: Imported coal = 8:1	Domestic gas: Imported coal = 6:1	50
Sabah	Domestic gas: Imported coal = 8:1	Domestic gas: Imported coal = 6:1	50
Philippines	Domestic gas: Domestic coal : Imported coal = 1:0.2:1.8	LNG: domestic gas: Domestic coal : Imported coal =1:0.5:0.1:0.9	300
Singapore	Imported gas	Only imported gas	300
Thailand	Imported gas: Domestic coal: Imported coal = 3:0.5:0.5	Imported gas: Domestic coal: Imported coal = 3:0.5:0.5	500

Source: EPDC, 2000

ASSUMPTIONS

The following data were submitted by APERC for the study:

- Fuel cost by type (coal, gas, oil) in each economy
- Capital cost per kW by type of power plant (coal, oil, gas, hydro)
- Operation and maintenance (O&M) cost by type of power plant
- Decommissioning year
- Technical minimum capacity for running unit
- Heat rate of thermal plant
- Difference in time for each economy
- CO_2 content by fuel

- Price escalation
- Discount rate
- Power loss caused by interconnection
- Daily load curve

RESULTS OF ANALYSIS

Prior to 2011, the calculation is made under the same conditions regardless of interconnections, so the same result is obtained for both cases.

After 2011, the interconnection system leads to savings from the difference in time between peaks, the differences in unit generation costs and reductions in the reserve margin (allowing capacity expansion plans to be extended). The results are shown in Table A 7 to Table A 9.

Table A 7 Comparison between isolated and connected cases (Scheme 1)

Economy	Total cost (generation cost only) (1,000 US$)			CO_2 (kt)		
	Isolated (A)	Connected (B)	(B)-(A)	Isolated (A)	Connected (B)	(B)-(A)
Brunei Ds	592,795	580,088	-12,707	26,738	24,973	-1,765
Sumatra	7,599,168	7,548,090	-51,078	479,521	478,864	-657
Java	24,543,550	24,542,314	-1,236	2,140,073	2,141,265	1,192
P. Malaysia	21,848,806	21,503,479	-345,326	1,270,115	1,250,559	-19,556
Sarawak	1,540,295	1,996,714	456,418	23,661	15,246	-8,415
Sabah	960,875	961,348	473	47,487	47,555	68
Philippines	12,111,073	12,111,073	0	735,908	735,908	0
Singapore	11,793,674	11,698,793	-94,880	472,868	460,224	-12,644
Thailand	31,437,989	31,053,680	-384,309	1,888,964	1,867,062	-21,902
Total	112,428,225	111,995,579	-432,646	7,085,335	7,021,656	-63,679

Source: EPDC, 2000

POWER EXCHANGE

Table A 10 shows the amount of power exchanged through each interconnection line. The directions of power flows based on the above are shown in Figure A 2 to Figure A 4. Generally, Thailand and Singapore are regions that import electric power, while Sumatra, and Sarawak export power.

Table A 8 Comparison between isolated and connected cases (Scheme 2)

Economy	Total cost (generation cost only) (1,000US$)			CO_2 (kt)		
	Isolated (A)	Connected (B)	(B)-(A)	Isolated (A)	Connected (B)	(B)-(A)
Brunei Ds	592,795	592,795	0	26,738	26,738	0
Sumatra	7,599,168	7,547,698	-51,470	479,521	478,810	-711
Java	24,543,550	24,542,393	-1,157	2,140,073	2,141,296	1,223
P. Malaysia	21,848,806	21,505,735	-343,070	1,270,115	1,250,150	-19,965
Sarawak	1,540,295	1,990,877	450,582	23,661	14,068	-9,593
Sabah	960,875	960,875	0	47,487	47,487	0
Philippines	12,111,073	12,111,073	0	735,908	735,908	0
Singapore	11,793,674	11,698,651	-95,023	472,868	460,229	-12,639
Thailand	31,437,989	31,053,218	-384,771	1,888,964	1,866,978	-21,986
Total	112,428,225	112,003,316	-424,909	7,085,335	7,021,664	-63,671

Source: EPDC, 2000

Table A 9 Comparison between isolated and connected cases (Scheme 3)

Economy	Total cost (generation cost only) (1,000$)			CO_2 (kt)		
	Isolated (A)	Connected (B)	(B)-(A)	Isolated (A)	Connected (B)	(B)-(A)
Brunei Ds	592,795	580,850	-11,945	26,738	25,074	-1,664
Sumatra	7,599,168	7,548,110	-51,058	479,521	478,868	-653
Java	24,543,550	24,542,305	-1,245	2,140,073	2,141,264	1,191
P. Malaysia	21,848,806	21,503,400	-345,406	1,270,115	1,250,550	-19,565
Sarawak	1,540,295	1,996,833	456,538	23,661	15,264	-8,397
Sabah	960,875	963,515	2,640	47,487	48,850	1,363
Philippines	12,111,073	12,057,310	-53,763	735,908	745,391	9,483
Singapore	11,793,674	11,698,744	-94,930	472,868	460,212	-12,656
Thailand	31,437,989	31,053,488	-384,501	1,888,964	1,867,037	-21,927
Total	112,428,225	111,944,556	-483,670	7,085,335	7,032,510	-52,825

Source: EPDC, 2000

Table A 10 Power exchange flows (2011 - 2020)

Direction of Power Flow	Scheme 1	Scheme 2	Scheme 3
		GWh	
From P. Malaysia to Thailand	33,978	34,120	33,999
From Thailand to P. Malaysia	11	13	11
From P. Malaysia to Singapore	20,735	20,803	20,742
From Singapore to P. Malaysia	15	15	15
From P. Malaysia to Sumatra	215	227	211
From Sumatra to P. Malaysia	6,582	6,510	6,584
From P. Malaysia to Sarawak	0	0	0
From Sarawak to P. Malaysia	39,372	40,481	39,416
From Brunei Ds to Sarawak	0	0	0
From Sarawak to Brunei Ds	3,391	0	3,381
From Brunei Ds to Sabah	249	0	307
From Sabah to Brunei Ds	528	0	390
From Philippines to Sabah	0	0	460
From Sabah to Philippines	0	0	3,261
From Java to Sumatra	2,226	2,260	2,225
From Sumatra to Java	1,199	1,199	1,200

Source: EPDC, 2000

POWER PLANT CAPITAL COSTS

Where peak power trimming is attained as a result of power exchanges, the scale of the overall power development programme is reduced and thus the capital costs can also be reduced.

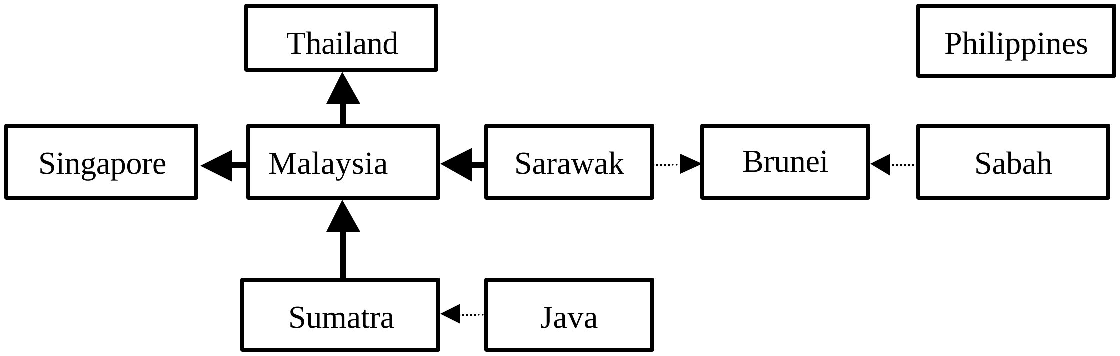
As a rule, interconnection does not lead to expansion of power development plans. However Bakun's hydropower capacity in Sarawak, which offset that in Peninsular Malaysia will increase with interconnection, so capital costs increase in line with the capacity expansion. As a whole, reserve margins are decreased, so capital requirements can be reduced by interconnection. This trend is common to all three schemes.

INTERCONNECTION PLANS IN EACH ECONOMY

The cost of each interconnection plan was assumed to be as follows.

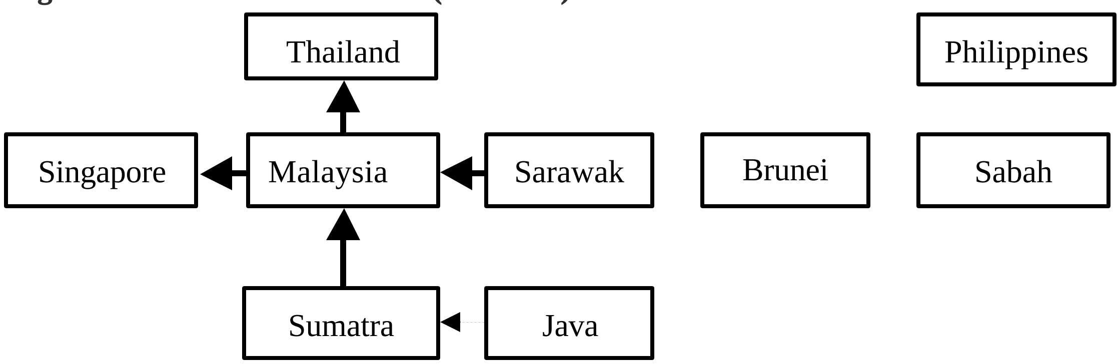
The capacity of the required equipment is based on the power flow obtained from the analysis for the interconnected case, and is used only for cost calculation. Note that the analysis was made on the assumption that the capacity when interconnected is limitless.

Figure A 2 Power flow direction (Scheme 1)



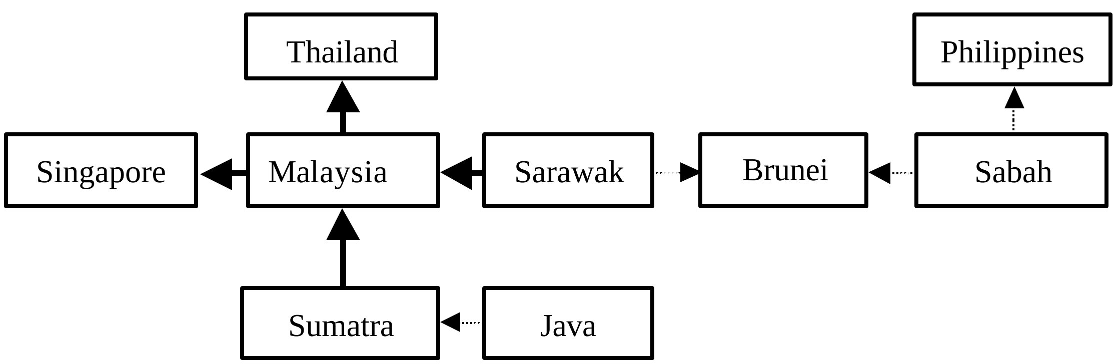
Source: EPDC, 2000

Figure A 3 Power flow direction (Scheme 2)



Source: EPDC, 2000

Figure A 4 Power flow direction (Scheme 3)



Source: EPDC, 2000

CONCLUSIONS

The analysis was almost the same for all of Schemes 1 to 3. Accordingly, overall evaluation, including expenses required for interconnection, will be made on the basis of Scheme 2.

Table A 11 Outline of each interconnection plan

Project	Capacity (MW)	Transmission Method
P. Malaysia – Thailand	600 (2014) 2,400 (2015)	HVDC(BTB)
P. Malaysia – Singapore	200 (2014) 700 (2015)	AC 500kV Substation +Cable(10km)
P. Malaysia – Sumatra	600	HVDC Over Head(85km) +Cable(50km)
P. Malaysia – Sarawak	1,500	HVDC Cable(650km)
Sumatra – Java	300	HVDC Over Head(80km) +Cable(40km)
Sarawak – Brunei Ds – Sabah	(Not strengthened)	AC 275kV Existing facility (1,200km)
Sabah – Philippines	300	HVDC Cable(1,120km)

Source: EPDC, 2000

Table A 12 List of cost elements

	Bearable Term	Unit Cost
Cable	30 years	DC cable (500kV): 400,000(US$/km)
		DC cable (250kV): 280,000(US$/km)
		DC Over Head (500kV): 400,000(US$/km)
		DC Over Head (250kV): 200,000(US$/km)
		AC cable (500kV): 2,100,000(US$/km)
AC/DC Converter	30 years	160(US$/kW)/both
AC Substation	30 years	\(AC Cable , Over head) × 20?
Indirect Cost		50% of Capital Cost
O&M Cost		10% of Capital Cost/year

Source: EPDC, 2000

FEATURES OF INDIVIDUAL INTERCONNECTION PROJECTS

INTERCONNECTION BETWEEN THAILAND AND PENINSULAR MALAYSIA

The power flow from Peninsular Malaysia to Thailand reaches almost 100 percent. As the kW value is large but the utilisation factor is small (about 27 percent), the kWh value is not so large. The flow of power (kWh) is mainly from Peninsular Malaysia to Thailand, because the unit fuel cost for thermal power generation is more expensive in Thailand than in Malaysia. Some of the gas and coal fired power in Peninsular Malaysia and Sarawak, and hydropower in Sumatra and Bakun flow toward Thailand due to the difference in power generation costs between these regions.

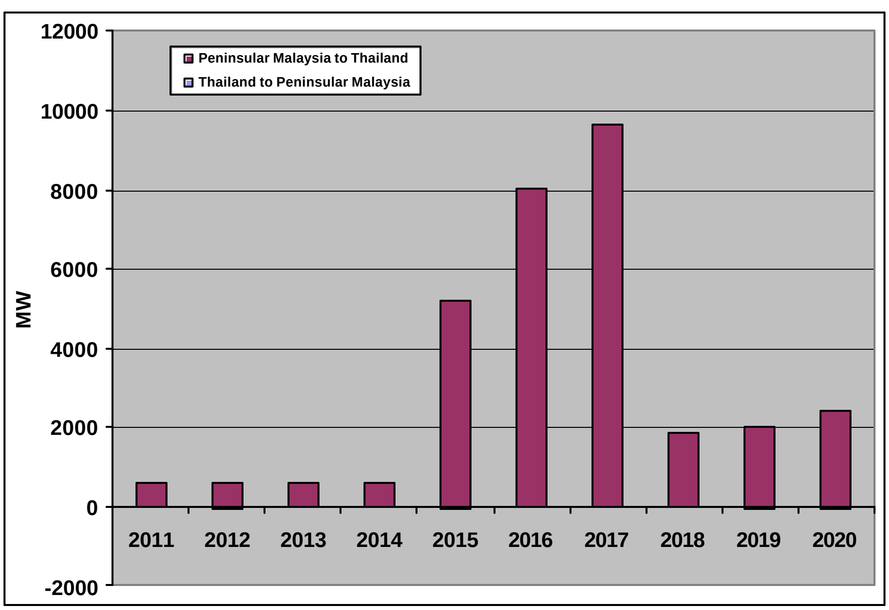
In addition, even if the total capacity of the interconnection system is increased to 2,400 MW (an extension of 1,800 MW), the amount of power transferred does not greatly increase (600 MW). For this reason, power exchanges (kWh) caused by the difference in fuel costs do not change much, but the above exchanges are considered to shift to peak power exchanges which fill the gap in power supply and demand between Thailand and Peninsular Malaysia caused by the difference between the 24-hour demand curves.

The reason the kW value, increases every year from 2015 till 2017, then decreases sharply in 2018 is due to the number of new and efficient thermal power plants which come on line to replace old thermal power plants in Thailand.

INTERCONNECTION BETWEEN PENINSULAR MALAYSIA AND SUMATRA

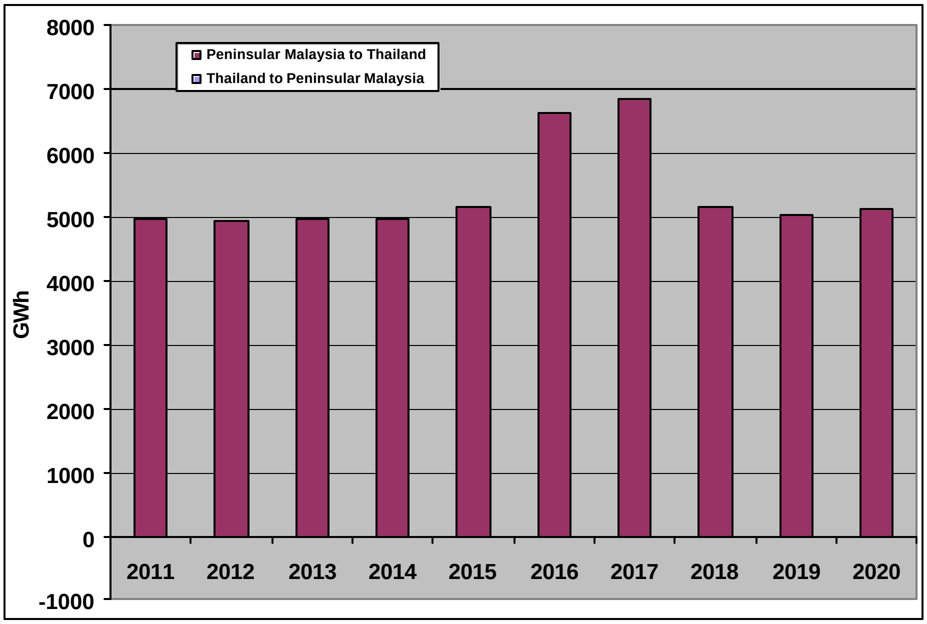
The power flows in both directions are quite large. However, almost all of the power exchanges are from Sumatra to Peninsular Malaysia judging from the kWh value. The interconnection is assumed to have a capacity of 600 MW, but the main reason the utilisation factor is small (about 20 percent) is considered to be the power exchanges between Peninsular Malaysia and Sumatra including Thailand to meet

Figure A 5 Power flow between Thailand and Peninsular Malaysia



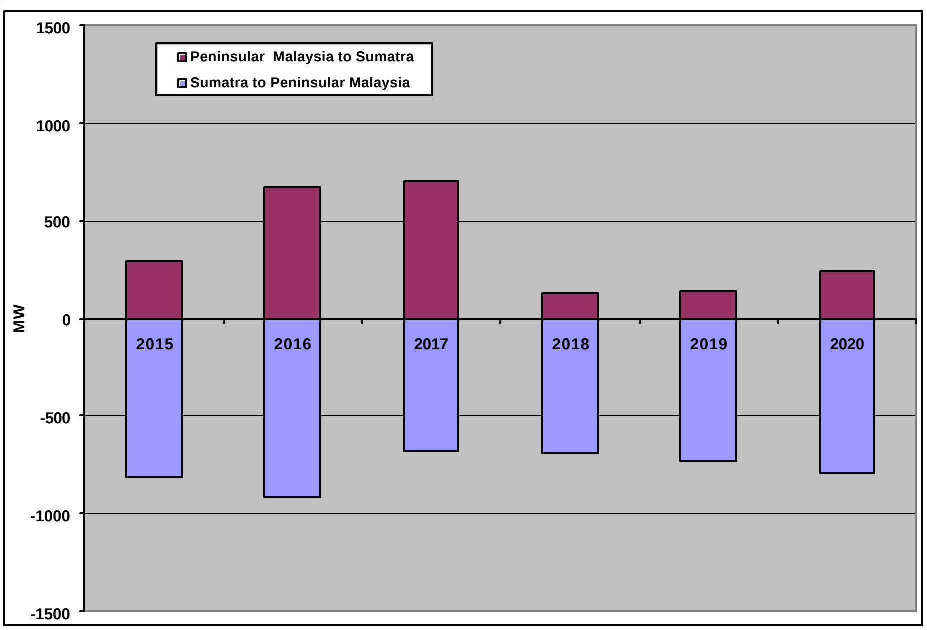
Source: EPDC, 2000

Figure A 6 Energy flow between Thailand and Peninsular Malaysia



Source: EPDC, 2000

Figure A 7 Power flow between Peninsular Malaysia and Sumatra



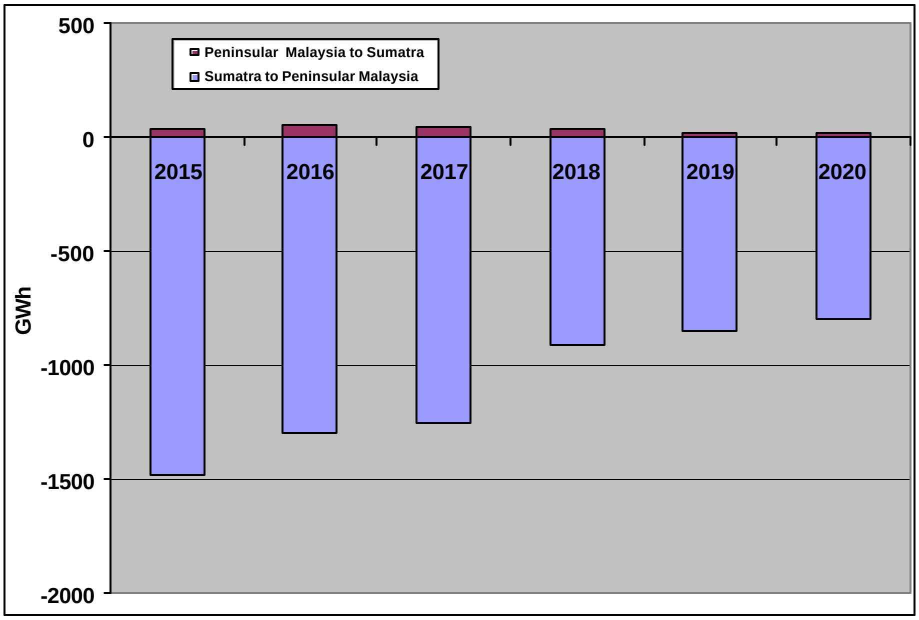
Source: EPDC, 2000

the peak power demand in each of these economies.

INTERCONNECTION BETWEEN PENINSULAR MALAYSIA AND SARAWAK

It is considered that both kW and kWh values reach certain levels in order to link with Bakun's power extension (750 MW x 2).

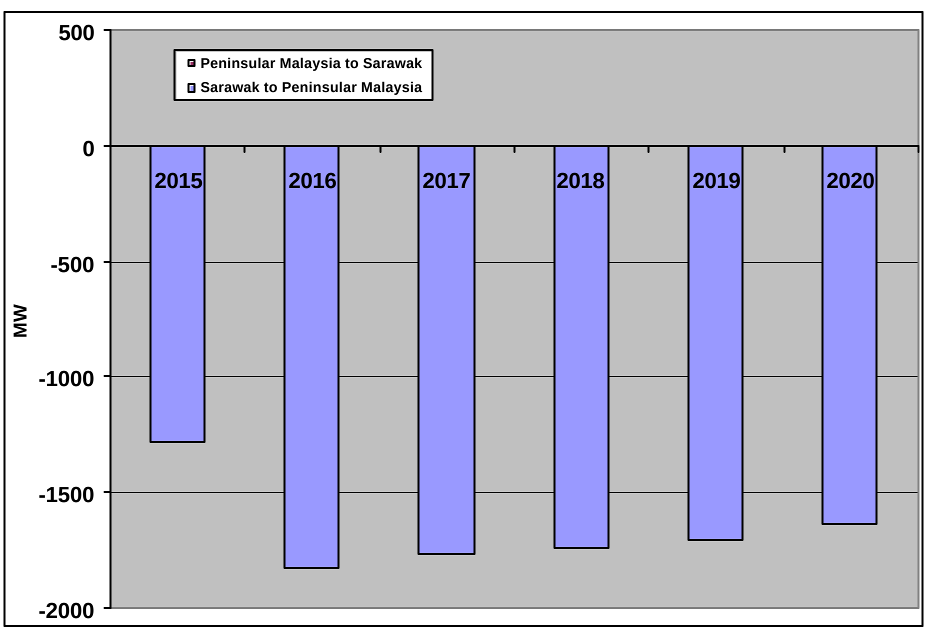
Figure A 8 Energy flow between Peninsular Malaysia and Sumatra



Source: EPDC, 2000

It is natural that the flow of power is directed toward Peninsular Malaysia. As Bakun is a supplier of base-load power, it is considered that almost all of the power other than that consumed in Bakun is directed toward Peninsular Malaysia. The capacity of the interconnection is assumed to be 1,500 MW (the same scale as the Bakun extension), but as the utilisation factor of the facility is not large (about 50 percent), about half of the power extension is considered to be consumed within Sarawak.

Figure A 9 Power flow between Peninsular Malaysia and Sarawak

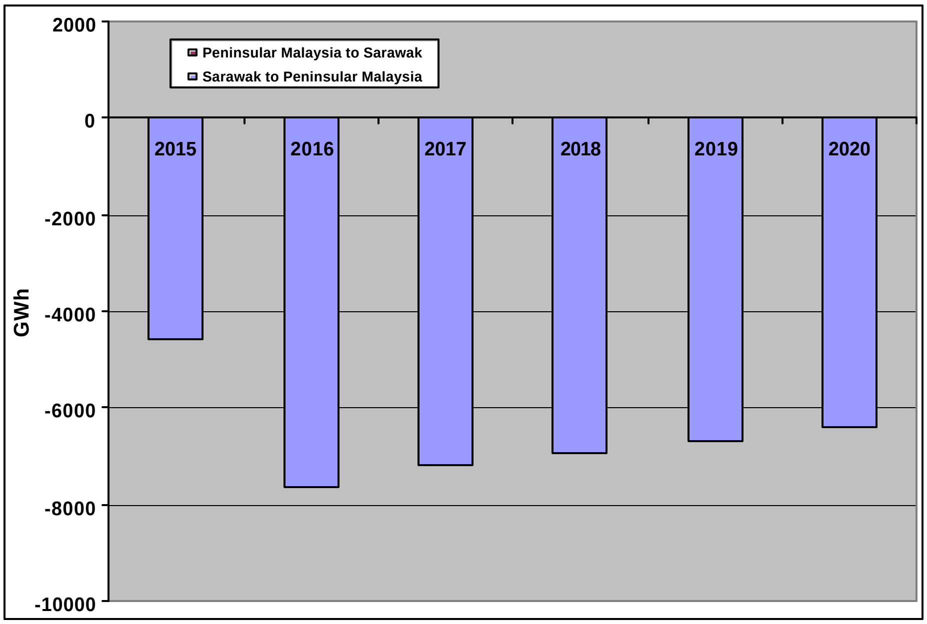


Source: EPDC, 2000

INTERCONNECTION BETWEEN SUMATRA AND JAVA

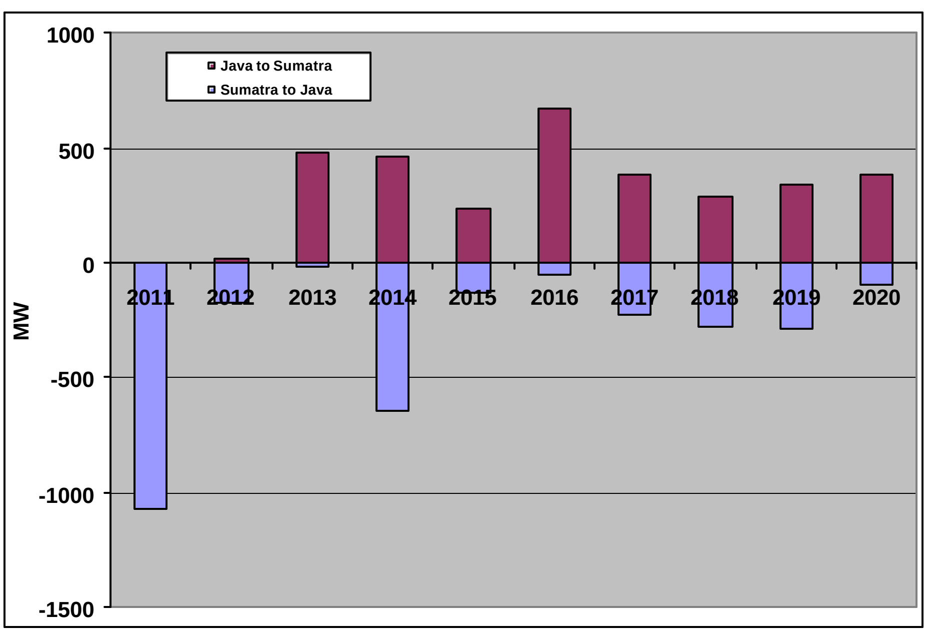
This interconnection is to be operational in 2011. The power flow goes in both directions, but the net flow is from Java to Sumatra. As the kWh value is small even if the kW value is large, peak power exchanges to manage supply and demand in the two regions are considered to be the main types of power exchanges.

Figure A 10 Energy flow between Peninsular Malaysia and Sarawak



Source: EPDC, 2000

Figure A 11 Power flow between Sumatra and Java

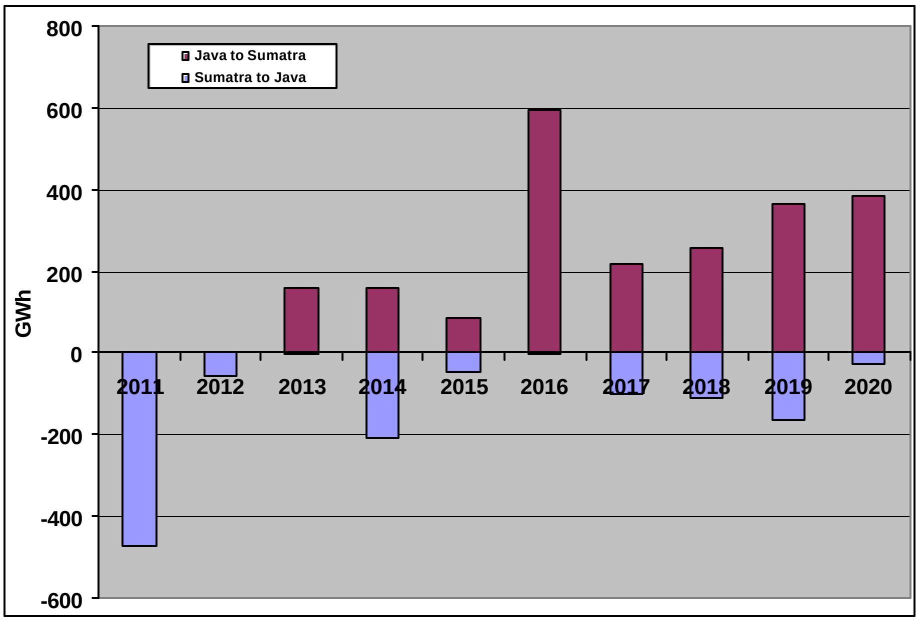


Source: EPDC, 2000

INTERCONNECTION BETWEEN PENINSULAR MALAYSIA AND SINGAPORE

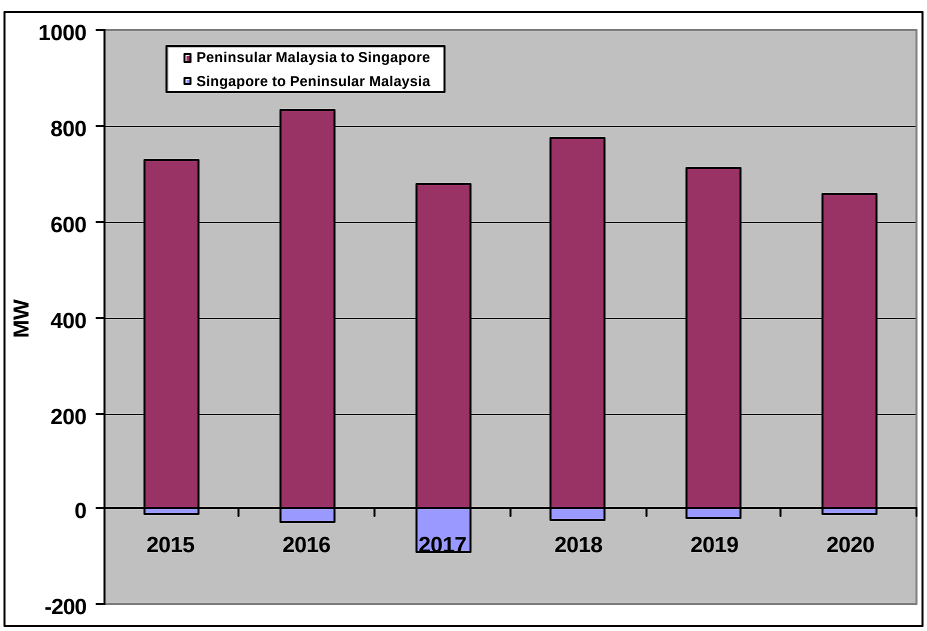
The power exchange is primarily from Peninsular Malaysia to Singapore. Some of the gas fired power in Peninsular Malaysia flows into Singapore due to the difference in the unit fuel costs (as Peninsular Malaysia produces gas, the unit fuel cost is less expensive than in Singapore where gas is imported). Some of the coal-fired power from Sumatra and hydropower from Sarawak also are assumed to flow to

Figure A 12 Energy flow between Sumatra and Java



Source: EPDC, 2000

Figure A 13 Power flow between Peninsular Malaysia and Singapore



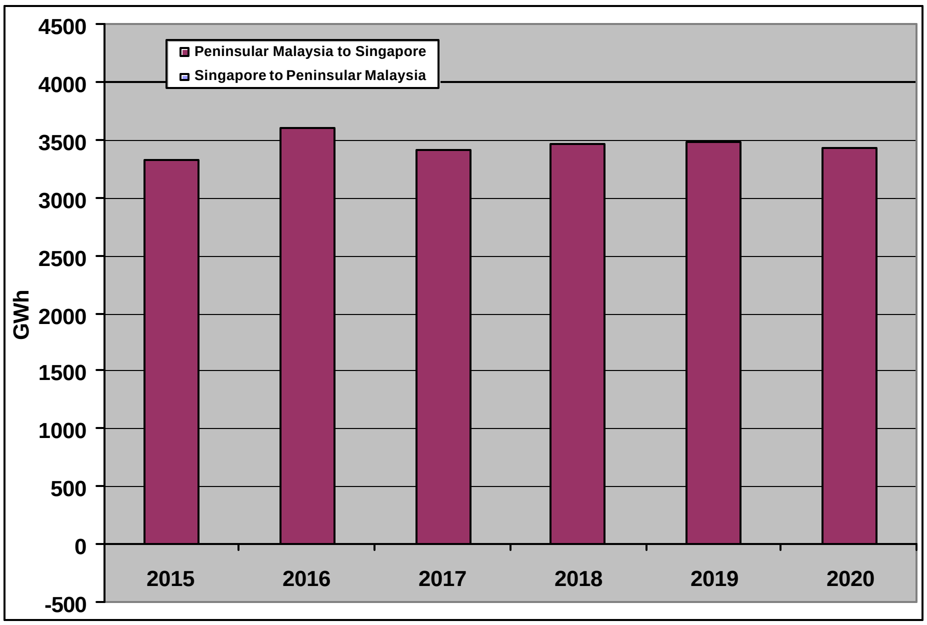
Source: EPDC, 2000

Singapore via Peninsular Malaysia. The capacity of the interconnection is assumed to be 700 MW, but the utilisation factor of the facility is about 56 percent.

SARAWAK, BRUNEI AND SABAH (SCHEME 1)

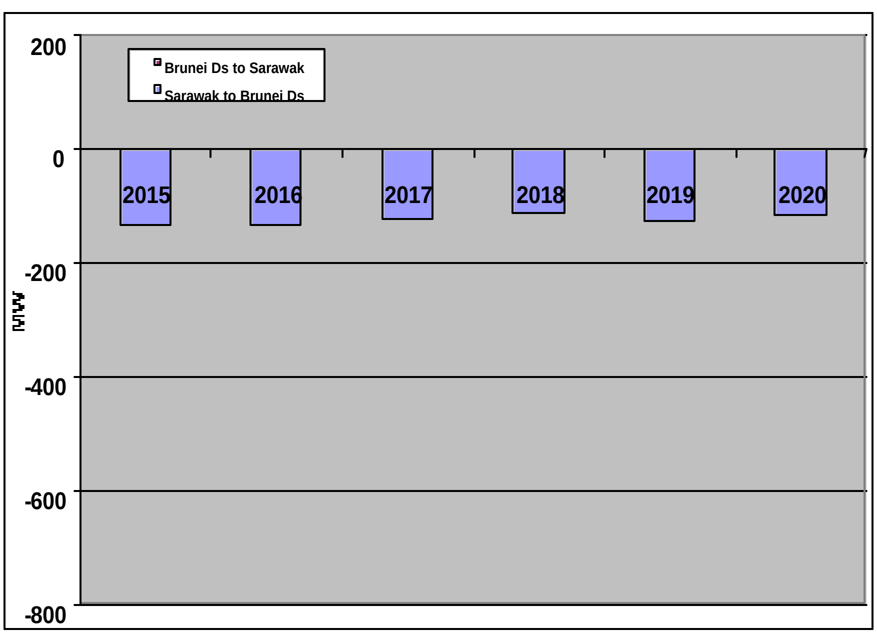
There are likely to be few power exchanges within these three regions. This is because of the small power demand (about 1,000 MW) expected in 2020 and because the difference in energy costs is small.

Figure A 14 Energy flow between Peninsular Malaysia and Singapore



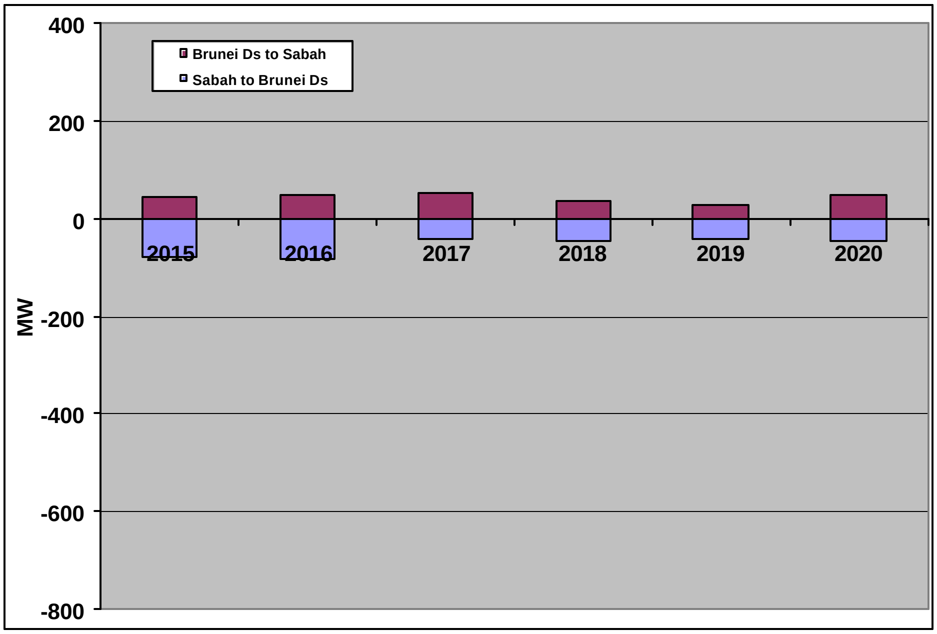
Source: EPDC, 2000

Figure A 15 Power flow between Sarawak and Brunei Darussalam



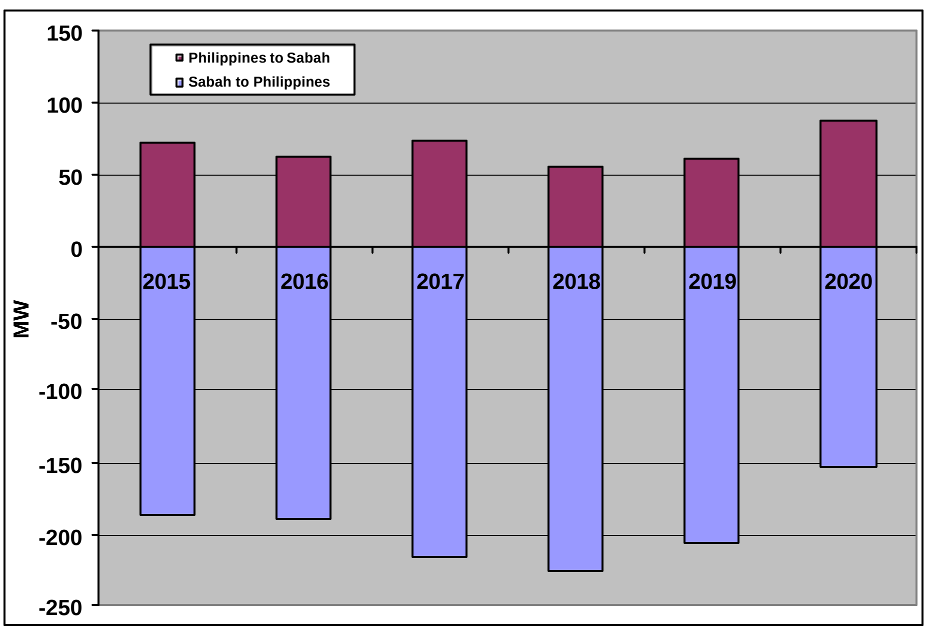
Source: EPDC, 2000

Figure A 16 Power flow between Brunei Darussalam and Sabah



Source: EPDC, 2000

Figure A 17 Power flow between Philippines and Sabah



Source: EPDC, 2000

Table A 13 Transmission line utilisation factors for Scheme 2

	Power exchange (GWh)	Transmission capacity (MW)	Utilisation factor (%)
Thailand – P. Malaysia	34,120	2,400	27
P. Malaysia – Singapore	20,803	700	56.5
P. Malaysia – Sumatra	6,510	600	20.6
P. Malaysia – Sarawak	40,481	1,500	51.1
Sumatra – Java	2,260	300	14.3

Source: EPDC, 2000

INTERCONNECTION BETWEEN SABAH & THE PHILIPPINES (SCHEME 3)

Example of calculation

If 1,000 GWh is exchanged between region A and region B within a given period of time (five years) for an interconnection line with a capacity of 100 MW, the utilisation factor is.

$$1{,}000 \text{ GWh} \div (100 \text{ MW} \times 24 \text{ hours} \times 365 \text{ days} \times 5 \text{ years}) = 22.8 \text{ percent}$$

Due to the transmission distance of about 1,100 km, and the small flows likely between Sarawak, Brunei Darussalam and Sabah, it is assumed that interconnection between these regions is not practical.

UTILISATION FACTOR

The interconnection utilisation factor is expressed as the ratio of the total power (kWh) exchanged in one direction (the direction in which the flow is larger) to the total capacity of the interconnection.

Interconnection projects between Sarawak, Brunei Darussalam and Sabah, and between Sabah and the Philippines were excluded as they were considered not to be practical.

OVERALL EVALUATION OF FEASIBILITY

The interconnection cost used for comparison is the total of all expenses from 2011 when the first interconnection facilities are completed until 2020. For this comparison, all of the expenses in each year are rebated to those in 1999 at a rate of 10 percent.

The benefit for each interconnection is obtained by proportionally dividing the total benefit by the amount of mutually exchanged power. However, the numeric value thus obtained shows only the tendency of the benefit.

The interconnection cost covers construction (capital cost + indirect cost) and annual expenses. The construction cost is calculated assuming that the life of interconnection line will be 30 years, and the cost will be evenly distributed on and after 2011.

Table A 14 Cost-benefit for interconnection transmission line for Scheme 2

	Benefit	Cost	Benefit-Cost
	Thousand US$		
Thailand – P. Malaysia	137,307	45,041	92,266
P. Malaysia – Singapore	83,744	3,941	79,803
P. Malaysia – Sumatra	27,101	20,800	6,301
P. Malaysia – Sarawak	162,843	159,520	3,323
Sumatra – Java	13,914	24,293	-10,378
Total	424,909	253,595	171,314

Source: EPDC, 2000

Annual interconnection expenses are evenly distributed after completion of the line, assuming that the ratio of the above expenses to the capital cost of these facilities is 10 percent.

METHOD OF BENEFIT DISTRIBUTION

Usually, if regional power interconnection is made for two or more power systems, the reserve margin decreases and the peak demand is cut in each interconnected region.

For this reason, it is expected that plans for new power generation developments can be extended, and thus the investment in power facilities is reduced. In addition, power exchanges reduce system operation costs compared to the operation of separate systems, thereby reducing variable costs.

The feasibility of an interconnection plan is evaluated by comparing an improvement in economic efficiency and cost relating to the construction and operation of the interconnected system compared to two separate systems.

Originally, it was considered desirable to make the evaluation over the economic lifetime of the interconnection line (the depreciation period). However, as no long-term power demand forecasts were available, and power development plans could not be expected to be accurate out that far, the evaluation was made only until 2020 (10 years from the start of operation of the interconnection line).

The size of interconnection lines was assumed from expected power flows, and the total cost was calculated on this basis. These assumptions led to the conclusion that the interconnected systems modelled would prove profitable in real life. However, various factors (political, economic, and technical) could have a large impact on an actual investment of this type in the real world. It is expected that more accurate results could be obtained by collecting more accurate and detailed data.

EVALUATION OF FEASIBILITY OF EACH INTERCONNECTION PROJECT

Almost the same result was obtained for Schemes 1 to 3. In addition, it was decided that an interconnection between Sarawak, Brunei Darussalam and Sabah and between Sabah and the Philippines should be excluded from further studies, as such interconnections are not considered practical by 2020.

On the other hand, the feasibility of other interconnection projects by 2020 was studied by calculating the assumed benefit of the relevant interconnection lines proportionally divided by the amount of power exchange (See Table A 14).

Each project is evaluated as follows.

INTERCONNECTION BETWEEN PENINSULAR MALAYSIA AND SARAWAK

The table suggests that this interconnection is not feasible. This is due to the construction cost of the project, involving a cable distance of 650 km. However, this interconnection should be studied in more detail in future, as this interconnection project could transmit Bakun's hydropower to peninsular Malaysia. The rated capacity of the exchanging facility is assumed to be 1500 MW (capacity equal to Bakun's power extension) from the kW value at the peak, but the utilisation factor is low (about 50 percent).

If the rated capacity of the interconnection line were reduced, assuming a high utilisation factor for a base-load supply facility, this interconnection project would have high feasibility.

INTERCONNECTION BETWEEN SUMATRA AND JAVA

Power exchanges occur due to the imbalance in power demand between these two regions. Some kW values are large, but the kW value changes every year. In addition, the utilisation factor is low as an interconnection line and the kWh value is also not large. If the kW value were higher through the establishment of a project that could increase the utilisation factor, the interconnection would be a feasible project.

INTERCONNECTION BETWEEN SUMATRA AND MALAYSIA

The kWh value is low with respect to the kW value of the interconnection line (a utilisation factor of about 20 percent). However, as the interconnection distance is comparatively short and the line cost not high, the project is considered feasible. The feasibility of this project would be further enhanced with an expansion to include Thailand.

INTERCONNECTION BETWEEN PENINSULAR MALAYSIA AND THAILAND

As only back-to-back facilities were taken into account, the cost of the interconnection is less expensive and the amount of exchanged power is large, so this is considered to be a feasible project. However, as the BTB facilities are installed at both ends of the AC system in Malaysia and Thailand, when extending the capacity of these facilities, the AC system to be interconnected must be strengthened. Therefore, the cost including that for strengthening the AC system needs to be evaluated.

INTERCONNECTION BETWEEN PENINSULAR MALAYSIA & SINGAPORE

Base power exchanges are permanently made from Peninsular Malaysia to Singapore due to the difference in energy costs resulting from the difference of gas fired fuel costs between Peninsular Malaysia and Singapore. For this reason, the utilisation factor of the facility shows a maximum value of about 56 percent. As the facility cost is not expensive because the transmission distance between Peninsular Malaysia and Singapore is short in spite of cable power transmission, this project is, in general, considered to be feasible.

On the other hand, this interconnection already exists, though it is always in the “OFF” state as it is for emergency use only.

INFLUENCE OF VARIOUS DATA ON THE CALCULATION RESULT

In this study, the calculation was performed for the period to 2020 as the target year. However, the following factors are considered to greatly affect the analysis depending on the input conditions for the calculation:

- PDP (Power Development Programme): Has a large influence.

The scenario of the power development programme, which is based on the demand forecast and energy policy of each region, has a large influence on the analysis.

Further, as the PDP has a large influence on the power production cost, capital cost and O&M cost, the analysis result may be different, if the details of the development programme are changed.

- Fuel cost: Has a large influence.

The direction and amount of power exchange between each region is determined by the power production cost resulting from the difference in fuel costs. For this reason, the assumed fuel cost greatly affects the analysis.

- O&M cost: Has a small influence.

As it is assumed that the ratio of the O&M cost to the capital cost is constant, if the PDP is changed, the O&M cost affects the analysis result by the rate of change of capital cost.

- Capital cost: Has a small influence.

The capital cost depends on the PDP, so if the PDP is changed, the capital cost naturally affects the analysis result.

- Discount rate: Has a small influence.

This affects the result depending on the year of facility operation.

This time, the discount rate was evenly set to 10 percent for all of the regions. However, assuming that each region employs a different discount rate, the rate thus employed for each region greatly affects the result.