ASIA PACIFIC ENERGY RESEARCH CENTRE

NATURAL GAS PIPELINE DEVELOPMENT

IN SOUTHEAST ASIA

MARCH 2000

Published by

Asia Pacific Energy Research Centre
Institute of Energy Economics, Japan
Shuwa-Kamiyacho Building, 4-3-13 Toranomon
Minato-ku, Tokyo 105 Japan
Tel: (813) 5401-4541
Fax: (813) 5401-4555
Email: okano@aperc.ieej.or.jp (administration)

ISBN 4-931482-07-4

FOREWORD

I am pleased to present the report of the second part of our research study on The Costs and Benefits of Large Scale Natural Gas Resource Development, Natural Gas Pipeline Development in Southeast Asia. The first part of the study, Natural Gas Pipeline Development in Northeast Asia is written in a separate report.

The objective of this study is to investigate the feasibility and viability of constructing large-scale natural gas pipelines to supply Southeast Asian energy markets and to facilitate policy makers with information that can be used to support decision making, to further encourage the development of cross-border pipeline infrastructure in the region.

This report provides the results of the research conducted by the Natural Gas Team in APERC. The work comprised of many precious comments and information provided by participants in workshops and conferences held by APERC in Japan. Please note, however, that this report is published by APERC as an independent study and does not reflect the views or policies of the APEC Energy Working Group.

Finally, I would like to thank all those who have been involved in this major and I believe successful exercise including the staff at the Centre, both professional and administrative, the experts who have helped us through our conferences and workshops, and many others who have provided interesting and useful comments. Not all views and opinions expressed in this report will be accepted, but they are a genuine attempt to fulfil the difficult task prescribed for the centre by the Experts Group on Energy Data and Analysis and the APEC Energy Working Group. I hope this report is useful to a wide audience.

Keiichi Yokobori
President
Asia Pacific Energy Research Centre

ACKNOWLEDGEMENTS

The development of this study could not have been accomplished without the contributions of many individuals. APERC would like to acknowledge and thank the people who made this report possible.

APERC CONTRIBUTORS

Project Leader:

Dr Hassan Ibrahim (Malaysia)

Members:

Abd. Shawal bin Yaman (Brunei Darussalam)

Dr Tran Thanh Lien (Viet Nam)

Iman Budi Santoso (Indonesia)

Punnchalee Laothumthut (Thailand)

OTHER CONTRIBUTORS/COMMENTATORS

Members (and Representatives) of the APEC Expert Group on Energy Data and Analysis

Dr Mohd. Farid Mohd. Amin, PETRONAS, Malaysia

Mohamad Awang Damit, Brunei LNG Sdn Bhd

James T. Jensen, Jensen Associates, Inc

Dr Thierry Lefevre, Centre for Energy-Environment Research & Development, Asian Institute of Technology

Dr Vichit Yamboonruang, Petroleum Authority of Thailand

EDITOR

Dr David Cope (New Zealand)

ADMINISTRATIVE SUPPORT

Sutemi Arikawa, Shohei Okano, Sachi Goto, Asako Haga and Junko Oonawa.

CONTENTS

List of Tables

LIST OF FIGURES

LIST OF ABBREVIATIONS

AAGR	Average annual growth rate
ABARE	Australian Bureau of Agricultural and Resource Economic
ACE	ASEAN Centre for Energy
ADB	Asian Development Bank
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
BSM	Brunei Shell Marketing Sendirian Berhad
BSP	Brunei Shell Petroleum Sendirian Berhad
BST	Brunei Shell Tankers Sendirian Berhad
BTU	British thermal unit
CCGT	Combined cycle gas turbine
CEERD	Centre for Energy-Environment Research and Development, Asian Institute of Technology
CH_4	Methane
CNG	Compressed natural gas
CO_2	Carbon dioxide
COW	Contract of work
DES	Department of Electrical Services, Brunei Darussalam
DOE	Department of Energy
DPCU	Dew point control unit
ECA	Energy Conversion Agreement
EDMC	Energy Data and Modelling Centre, Japan
EFS	Environmentally Friendly Scenario
EGAT	Electricity Generating Authority of Thailand
EIA	Energy Information Administration, USA
EVN	Electricite de Viet Nam
EWG	Energy Working Group
FGHC	First Gas Holdings Corporation, Philippines
FSU	Former Soviet Union
GATT	General Agreement on Tariffs and Trade
GDP	Gross domestic product
GHG	Greenhouse gas
GMSB	Gas Malaysia Sendirian Berhad
GPP	Gas processing plant
GSA	Gas sales agreement
GSP	Gas separation plant
GW	Gigawatt
GWh	Gigawatt hour (= one million kilowatt hours)
HAPUA	Heads of ASEAN Power Utilities/Authorities
IE	Institute of Energy, Viet Nam
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IPPs	Independent power producers

JDA	Joint Development Authority (Malaysia – Thailand)
JEJV	Jasra-Elf Joint Venture, Brunei Darussalam
JOA	Joint Operation Agreement
KBD	Kilo barrels per day
KEPCO	Korea Electric Power Corporation
KOGAS	Korea Gas Corporation
KL	Kuala Lumpur
km	Kilometre
Ktoe	Kilo-tonnes of oil equivalent
LA	Loan agreement
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MBOE	Million barrels of oil equivalent
MEPE	Myanmar Electricity Power Enterprise
MERALCO	Manila Electric Company, Philippines
MMBTU	Million metric British thermal units
MMCM	Million metric cubic metres
MMCMD	Million metric cubic metres per day
MMCMY	Million metric cubic metres per year
MODB	Ministry of Development, Brunei Darussalam
MTBE	Methyl-tertiary-butyl-ethylene
MTJA	Malaysia-Thailand Joint Authority
Mtoe	Million tonnes of oil equivalent
MW	Megawatts (= 1,000 kilowatts)
NECB	National Energy Coordinating Board, Indonesia
N_2O	Nitrous oxide
NEPC	National Energy Policy Council, Thailand
NEPO	National Energy Policy Office, Thailand
NG	Natural gas
NGCC	Natural gas combined cycle
NGV	Natural gas vehicle
NOCs	National oil companies
NOGCs	National oil and gas companies
NO_X	Nitrogen oxides
NPC	National Power Company, Philippines
NRE	New and renewable energy
OCA	Overlapping Claims Area (Cambodia - Thailand)
ODA	Overseas Development Agency, Japan
OPEC	Organisation of Petroleum Exporting Countries
pa	per annum
PCSB	PETRONAS-Carigali Sendirian Berhad, Malaysia
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
PLN	Perusahaan Listrik Negara, Indonesia
PNG	Pipeline natural gas
PNOC	Philippines National Oil Company
PNOC-EC	Philippines National Oil Company-Exploration Corporation
PPA	Power purchase agreement
PSC	Production sharing contract
PSC	Protracted Crisis Scenario
PTT	Petroleum Authority of Thailand

PUB	Public Utility Board, Singapore
SESB	Sabah Electricity Sendirian Berhad, Malaysia
SESCO	Sarawak Electricity Supply Company, Malaysia
SOE	State-owned enterprise
SO_X	Sulphur oxides
SPP	Small power producer
TAC	Technical assistance contract
TCF	Trillion cubic feet
TNB	Tenaga Nasional Berhad, Malaysia
Toe	Tonne of oil equivalent
TAGP	Trans ASEAN Gas Pipeline
TPA	Third-party access
TPEC	Total primary energy consumption
TTM	Trans-Thailand Malaysia
US	United States (of America)

Table of Conversion Factors

APPROXIMATE CONVERSION FACTORS FOR NATURAL GAS AND LNG

From	To					
	BCM (NG)	BCF (NG)	Mtoe	Million tonnes (LNG)	Trillion BTU	MBOE
	Multiply by					
1 BCM (NG)	1	35.3	0.90	0.73	36	6.28
1 BCF (NG)	0.028	1	0.026	0.021	1.03	0.18
1 Mtoe	1.111	39.2	1	0.805	40.4	7.33
1 million tones (LNG)	1.38	48.7	1.23	1	52.0	8.68
1 trillion BTU	0.028	0.98	0.025	0.02	1	0.17
1 MBOE	0.16	5.61	0.14	0.12	5.8	1

Source: BP Amoco, 1999

EXECUTIVE SUMMARY

This is the report of Part II of APERC's study, "The Costs and Benefits of Large Scale Natural Gas Resource Development". While Part I of the study focused on natural gas development in Northeast Asia (China, Japan and Korea), Part II focuses on Southeast Asia which includes all seven APEC economies, namely Brunei Darussalam, Indonesia, Malaysia, Philippines, Singapore, Thailand, and Viet Nam. Myanmar, being a gas producer and exporter in Southeast Asia, is also included.

The general objective of this report is to provide policy makers with information that can be used to support decision making to further encourage the development of cross-border pipeline infrastructure in the region. The specific objectives include assessing the latest gas reserves and market potential in Southeast Asia, assessing the latest scenarios for natural gas infrastructure development in the region, and highlighting the benefits and barriers of gas pipeline interconnections.

Natural gas is an important commodity to Southeast Asia. For Southeast Asian economies that have for many years been overly dependent on oil and coal as their main energy sources, natural gas represents a desirable alternative. For economies pursuing energy policies placing high priority on energy diversification, security of supply, and environmental protection, natural gas – as a result of its abundance, inherent qualities and relative environmental friendliness - is becoming increasingly utilised. It is also an important export commodity, earning substantial foreign exchange.

Southeast Asia's gas statistics for 1998 indicate that out of a total production of 120.6 BCM, 52.3 percent (63.6 BCM) was exported in the form of LNG to Northeast Asia (Japan, Korea and Chinese Taipei). Intra-trading of natural gas for that year occurred only between Malaysia and Singapore, at 1.5 BCM. Natural gas trading within the region represented only 2.3 percent of the total natural gas traded to outside markets.

Current proven reserves in Southeast Asia stand at around 5,620-7,873 billion cubic metres (BCM), which at the current rate of production will last for 41-57 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.

Despite the economic downturn that hit Asia in mid-1997, resulting in negative demand growth for all other energy forms in Southeast Asia, growth in the consumption of natural gas remained high over the period from 1997 to 1998. Between these two years primary energy consumption of oil, hydro-electricity and coal had grown by -5.0, -8.4 and -10.0 percent, whereas for gas the growth recorded was positive at 9.1 percent. With regional economies now recovering, the use of energy - in particular natural gas - is expected to increase again annually although in the first few years the growth in demand may not reach as high as pre-crisis growth rates.

The Asia Pacific Energy Research Centre (APERC) has projected that natural gas demand in Southeast Asia in 2010 will vary between 99.4 Mtoe (Protracted Crisis Scenario - PCS) and 118.5 Mtoe (Environmental Friendly Scenario - EFS). This is an average annual increase of 3.2 to 4.5 percent from the actual gas demand of 61.4 Mtoe in 1995. This fifteen-year forecast period increase is significantly less than the average annual increase of 13.1 percent during the same fifteen-year period from 1980 to 1995.

Power generation consumes most of the current as well as the projected demand in 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 much shorter time compared to power plants of other fuel sources, makes natural gas even more attractive as fuel in power plants, either for base load or peaking load.

Southeast Asian 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.

Although current domestic and commercial use is low due to lack of pipeline and reticulation infrastructure, there is considerable potential for more use of natural gas, especially for cooking, water heating and lately absorption-cycle air-conditioning. The planning, designing and construction of natural gas reticulation systems to residential and commercial areas could become a significant new service industry in major cities in Southeast Asia, providing opportunities for investment and business activities.

Southeast Asia, in general, is highly committed to encourage the use of natural gas across various sectors. Currently, the total length of domestic transmission and distribution pipelines is around 8,766 km, with the following breakdown in decreasing order: Indonesia (4469 km), Malaysia (1753 km), Myanmar (1,120 km), Brunei Darussalam (920 km), Thailand (377 km), Vietnam (127 km). With a number of pipelines now under construction and being planned, the total distance of domestic transmission and distribution pipelines in the region by 2005 would be around 10,000 kilometres.

The popularly conceived Trans-ASEAN Gas Pipeline (TAGP) will not be constructed as a mega joint-venture project between member economies but rather realised by the development of discrete cross-border pipelines. The TAGP is certainly under formation – but its exact routing will be determined by gas availability and market requirements, and financed and constructed by multi-national oil and gas companies.

Currently two cross-border pipelines (Malaysia-Singapore and Myanmar-Thailand) are in existence totalling 1,379 kilometres. More cross-border pipelines are either under construction or being planned. By 2005, five of the six Southeast Asian economies will be interconnected by cross-border pipelines, namely: Malaysia-Singapore, Myanmar-Thailand, Indonesia-Singapore, and Thailand-Malaysia, with a total cross-border pipeline length of about 3000 kilometres. By the year 2020 or probably much earlier, most if not all, Southeast Asian economies will be interconnected by major trunk lines.

With the existence of trunk cross-border pipelines traversing across different supply and market points, the existing domestic pipelines, with their future branching network to supply gas to consumers of different sectors, will play a role as lateral pipelines interconnecting together the cross-border pipelines. Hence by the year 2005 total gas pipeline span across Southeast Asia will be about 13,000 km, with total trans-border gas transportation capacity of 260 MMCMD.

The contrasting difference between the European Union, where natural gas has penetrated to a wide range of sectors, and Southeast Asia where gas is predominantly used in the power sector, can be seen by comparing gas consumption and length of pipelines in both regions. In 1997, the European Union consumed 335.5 BCM of natural gas - 5.3 times more than the 63.8 BCM consumed by Southeast Asia in the same year. The total length of the European Union's regional and local pipelines in place then was 1,100,000 km. This is 137 times more than the total length of Southeast Asia's transmission and distribution pipelines, estimated at about 8,000 km in that same year.

Currently Brunei Darussalam, Indonesia, Malaysia and Myanmar are potential pipeline natural gas (PNG) exporters whereas Thailand and Singapore, with energy security, diversification and environment protection high on their energy policy agendas, are potential importers. The

Philippines's Energy Plan 2000 – 2008 concentrates on self-reliance with respect to its own natural gas resources.

Indonesia's Natuna D-Alpha remains Southeast Asia's biggest untapped gas field with a proven reserve of 1,260 BCM. Strategically located at the geographical centre of Southeast Asia, this gas field is poised to be the future main supplier of natural gas to Southeast Asian economies. However, the total project cost to put this natural gas on stream is very high, currently estimated at US$ 42 billion. This is due to the high carbon dioxide content of the gas (72 percent). Hence Natuna's gas, either transported by PNG or LNG is expected to cost more than gas from most other fields.

Each economy in Southeast Asia has its own institutional and regulatory mechanisms with respect to natural gas exploration, production, transportation and utilisation. Operation of a cross-border pipeline needs a set of rules, regulations and pricing structure that fulfil the interests of all parties involved. A good understanding of each economy's institutional and regulatory regimes with respect to natural gas is necessary before the rules governing the cross border pipeline are derived. They should be transparent and easily understood by potential investors.

The private sector together with national oil and gas companies (NOGCs) will continue to play the key role in pursuing the development of cross-border pipeline projects. While governments are experiencing constrains with respect to the resources needed to finance infrastructure projects, the private sector is increasingly capable of providing the necessary capital to develop new natural gas infrastructure projects and associated trading networks in the APEC region. National development regulations should allow private ownership of natural gas facilities and the assignment of security interests in assets.

In all Southeast Asian economies the responsibility of developing natural gas resources has been entrusted to NOGCs. The operations of these NOGCs vary from one economy to another, from concession agreements to being full operating partners, and from being a fund-borrower to being self-funded in joint-venture projects. A stronger co-operation among NOGCs is encouraged in pursuing projects that have regional benefits as well as national benefits.

Governments have an important role to play to encourage the development of natural gas supply and transportation infrastructure. Government's will need to establish autonomous regulators with technical capacity, independent decision-making powers and power to enforce regulations to regulate the natural gas sector and ensure that private and public participants are treated on a fair basis.

CHAPTER 1

INTRODUCTION

Southeast Asia, by historical and geographical definition, constitutes the ten economies situated in the South China Sea and along the west coast of the Pacific and located between China and India (please see Figure 1). In August 1967, five of the more developed economies, Indonesia, Malaysia, Philippines, Singapore and Thailand established and became the founding members of the Association of Southeast Asian Nations (or ASEAN). Brunei Darussalam joined ASEAN in 1984, Viet Nam in 1995, Lao PDR and Myanmar in 1997, and Cambodia a year later. In 1998, thirty-one years after its establishment, all ten economies of Southeast Asia have become full members of ASEAN. Some socio-economic and energy indicators are provided in Appendix I for each of the ten economies.

Figure 1 Map of Southeast Asia

ASEAN's main aims and purposes are to accelerate economic growth, social progress and cultural development in the region through joint endeavours in the spirit of equality and partnership in order to strengthen the foundation for a prosperous and peaceful community of Southeast Asian nations, and to promote regional peace and stability through abiding respect for justice and the rule of law in the relationship among countries in the region and adherence to the principles of the United Nations Charter (ASEAN website). Energy cooperation is one of the sectoral cooperation activities in ASEAN and is governed by the ASEAN Agreement on Energy

Cooperation, 1986, covering a broad range of areas categorised under energy sources as well as upstream and downstream activities.

Seven of the Southeast Asian economies are members of the Asia Pacific Economic Cooperation (APEC), the grouping of economies along the Pacific Rim whose main objective is fostering economic cooperation through trade liberalisation. These economies are: Brunei Darussalam, Indonesia, Malaysia, Philippines, Singapore, Thailand and Viet Nam, with Viet Nam being the youngest member, admitted into APEC in 1997.

Southeast Asia's position in the world's natural gas sector is marked by its rank as the world's largest exporter of liquefied natural gas (LNG). Indonesia, Malaysia and Brunei Darussalam are Southeast Asia's biggest natural gas exporters, which with a total production of 120.6 BCM (108.7 Mtoe) in 1998, amounted to 5.3 percent of the world's natural gas production. Of this total production 63.6 BCM (52.3 percent) was exported to Japan, Korea and Chinese Taipei, in LNG form. Total LNG exports from Southeast Asia corresponded to 56.2 percent of the total global LNG trade movements in 1998.

Thailand and Viet Nam also have significant natural gas reserves, but their gas production is specifically targeted at domestic consumption, with most of the gas being utilised for power generation. Myanmar has recently joined the ranks of gas exporters in the region, shipping gas to neighbouring Thailand by pipeline. The Philippines is still developing its infrastructure at the Camago-Malampaya gas field for domestic use and is planning to have its first delivery in the year 2002. Laos, rich in hydropower potential, is not known to have any natural gas resources, whereas Cambodia, which has been identified as having prospective gas resources is only beginning to undertake exploration. Singapore is the only Southeast Asia member economy without any indigenous energy resources.

Although most Southeast Asian economies have streamlined their energy policies and strategies to include natural gas as part of their energy supply security and environmental protection measures, domestic use of natural gas is still relatively low due to a lack of pipeline infrastructure. Most domestic use of natural gas is for power generation while very little is being utilised in the industrial, residential-commercial and transportation sectors.

As mentioned above, natural gas trade in Southeast Asia is primarily dominated by the LNG business. The existing LNG infrastructure has a capacity of 36 million tonnes per year, of which 61 percent is in Indonesia, 24 percent is in Malaysia, and 15 percent is in Brunei Darussalam. LNG is economically suitable for long distance transportation, and for many years Japan, Korea and Chinese Taipei (Northeast Asia) have been secure LNG markets for Southeast Asia's natural gas through long-term sale and purchase contracts. In the future, the prospects for additional demand for natural gas in Northeast Asia look good, and LNG exports should continue even though this region is looking to import pipeline gas from fields in the eastern part of Russia.

For shorter distances, natural gas is more economically transported by pipeline. The first trans-border gas pipeline in Southeast Asia was completed in 1992 when Peninsular Malaysia's domestic pipeline network was extended by a few kilometres to Singapore. Southeast Asia's second and currently longest trans-border pipeline was completed in 1998, connecting the offshore Yadana gas field in Myanmar to the Ratchaburi power plant in Thailand. A sister pipeline from offshore Myanmar, from the Yetagun gas field, is now under construction and is planned for completion in the year 2000 - to be connected to the Yadana-Ratchaburi pipeline at the Myanmar-Thailand border. This latter pipeline would then form Southeast Asia's third cross-border link. The fourth trans-border pipeline in Southeast Asia is expected to be ready in the year 2001, connecting Indonesia's West Natuna gas field to Singapore.

Before the end of the year 2000, the two cross-border pipelines currently in existence will have a total length of 1,363 km. By the end of the year 2005 the total length of cross-border pipelines in place in Southeast Asia will be 3,451 km. The TAGP that has for many years been a dream, is actually in the making.

More trans-border natural gas pipelines may be realised in the future, as Southeast Asian nations move forward economically. Following the Second Informal ASEAN Heads of Government meeting in Kuala Lumpur on 15 December 1997, in which the "ASEAN Vision 2020" was adopted, the year 2020 has become a landmark for ASEAN economies in general to reach a certain level of economic development. The year 2020 is also a target for the region to have an interconnected energy infrastructure, comprising electricity grids and natural gas pipeline interconnections.

The prevailing economic crisis in Asia, which has badly affected the three economies once known as the "Southeast Asian tigers" - namely Indonesia, Thailand and Malaysia - may slow natural gas infrastructure development for a period of time. However, these economies are undergoing a restructuring process, and are confident their economies will be back on track within the next one or two-year period. In fact, Malaysia and Thailand recorded positive economic growth in 1999.

Economic analysts have forecast that the region's economic growth to 2001 will be positive but sluggish. Over the longer term, when the various reforms initiated during the financial crisis have begun to take effect, the growth in energy demand will rise high again, although it will still be modest compared to the pre-crisis period. Electricity demand will grow most strongly, and this will push further the demand for natural gas. Natural gas will also penetrate more into the non-electricity sectors. The existing pipeline infrastructure is just not adequate to transport the future projected volumes of gas required by the region.

CHAPTER 2

GAS PIPELINE INTERCONNECTION BENEFITS

The main benefits of natural gas over other fossil fuels are that it is relatively environmentally clean fuel and requires minimal processing prior to use.

Natural gas prices tend to be regulated, unlike the situation for oil and coal. Although price of gas may be generally indexed to the price of crude oil, the formula varies from one economy to another depending on whether the price is government regulated, market oriented or somewhere in between. In a market driven pricing structure, natural gas prices are usually negotiated between vendors and purchasers - subject to wellhead costs, processing and transportation costs. Generally, gas is less expensive than fuel oil but more expensive than coal (on an energy content basis). More information on the gas pricing structure is provided in Chapter 5.

Natural gas is predominantly used in the electricity generation sector - providing an alternative to oil and coal. Petrochemical products are derived from natural gas, and gas is used as an important feedstock for fertiliser manufacture. In commercial complexes and office buildings natural gas has long been utilised in cold climate areas for space heating. With its more widespread availability in hot climate areas, natural gas has found new applications in space cooling. The efficiencies of current air-conditioning technologies however limit such applications to large systems only and consequently natural gas cooling is now slowly gaining attention as an alternative in big commercial and office complexes. In domestic homes in warm climate regions, natural gas use is confined more to water heating and domestic cooking.

Natural gas has also found uses in the transportation sector. Because of its environmentally benign characteristics, compressed natural gas (CNG) is considered as a possible future alternative fuel for motor vehicles, reducing the sector's over-dependence on oil.

As many references are available on the applications and technological development of natural gas fuelled systems, this chapter just highlights the environmental benefits of natural gas and benefits pertaining to pipeline interconnections.

ENVIRONMENTAL BENEFITS

Natural gas emissions contain significantly lower levels of carbon dioxide, hydrocarbons and nitrogen oxides compared to other fossil fuels such as oil and coal, and therefore improved air quality after combustion is possible with a switch to gas. Natural gas is generally composed of at least 90 percent methane, and may contain other hydrocarbons in small quantities including ethane, propane and butane.

The major environmental impacts associated with hydrocarbon combustion are: (1) local air pollution problems such as SO_2, NO_x and particulate emissions (in the vicinity of large fossil fuelled power plants and in big cities with heavy traffic congestion); (2) regional problems such as acid rain and acid deposition in lakes and forests; and (3) global problems which are a direct result of emissions of greenhouse gases, in particular, carbon dioxide (CEERD, 1999).

Table 1 shows a comparison of gas emissions from power generation (Batelle, 2000). Natural gas is the superior fuel in terms of thermal efficiency and gas emissions compared to other fossil fuel sources. At around 50 percent thermal efficiency for modern gas fired combined cycle plants, this exceeds that for other combustion sources. The thermal efficiency is expected to reach 56 - 60 percent by the year 2010 (IEA, 1997). SO_2 emissions are negligible, and NO_X emissions vary from 1 - 6 times less than emissions from oil fired plants, and 6 - 10 times less than those of coal fired plants (depending on plant designs). Carbon dioxide emissions are also about 69 percent less than for oil fired plants, and more than 100 percent less than for coal fired plants. From this comparison natural gas clearly indicates its superiority in terms of mitigating environmental problems resulting from power generation.

Table 1 Gaseous emissions from fossil fuelled power plants

Plant Type	SO_2 (g/kWh)	NO_X (g/kWh)	CO_2 (g/kWh)	Thermal Efficiency (%)
Gas (Combined Cycle)	~ 0	0.5 - 2	370	50
Integrated Gas Combined Cycle (IGCC)	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: Batelle Memorial Institute website

BENEFITS OF PIPELINES INTERCONNECTION

PIPELINE NATURAL GAS (PNG) VERSUS LIQUIFIED NATURAL GAS (LNG)

LNG supply is currently confined to large-scale industries such as fuel for power plants or as feedstock for petrochemical and fertiliser plants. Without a pipeline network to feed the gas into, there is less flexibility for use for other (smaller-scale) applications.

With a pipeline infrastructure in place, gas can be transported continuously to different consumers with ease. With a secured supply, it avoids customers having to worry about the construction of stock or storage facilities, and gives the customers versatility in terms of fluctuations in daily use.

The versatility of a pipeline network can best be described by comparing the pipeline network in the European Union with that in Southeast Asia. In the European Union natural gas is widely utilised across all sectors whereas in Southeast Asian its application is mostly confined to the power sector, taking up about 71 percent of the total gas use (see Chapter 3). In terms of total volume of gas use, natural gas consumption in the European Union in 1997 was 335.5 BCM (Guillot, 1999), which was 5.3 times the gas consumption of Southeast Asia in the same year, at 63.8 BCM. The wide-scale penetration of natural gas into Europe has been facilitated by 1,100,000 km of regional and local pipelines, as compared to about 8,000 km of transmission and distribution pipelines in Southeast Asia (discounting pipelines built to connect gas fields to liquefaction plants). In terms of total pipeline length, this is a comparison ratio of about 137 times.

IMPROVING ENERGY SUPPLY SECURITY

Southeast Asia is a region well endowed with different types of energy resources, and in varying amounts. For several decades the region (in particular, Brunei Darussalam, Indonesia and Malaysia) have become oil exporters, and based on figures as of January 1999, the proven oil reserves were expected to meet the production demand of the region for 12 years (BP Amoco). 1992 was a turning point in terms of energy supply security for Southeast Asia when the region became a net oil importer (AEEMTRC, 1998). Since that year crude oil imports to the region had surpassed indigenous crude oil and petroleum products exports, and the margin has been increasing every year due to increasing oil demand, particularly in the transportation and industrial sectors.

Coal reserves are also found in abundance in Indonesia and Viet Nam, with both economies widely exporting to neighbouring economies as well as outside the region. Indonesia has the highest share of proven coal reserves in the region, with a reserve-to-production ratio of 87 years at January 1999 (BP Amoco, 1999). The greatest impediment to coal finding greater utilisation, especially in the power generation sector, is its higher gas emissions compared to oil and natural gas, as indicated in Table 1.

Natural gas offers additional energy supply security to the region. During previous years, when oil reserves were depleting, additional gas reserves were discovered. In Chapter 3 it is shown that the current gas reserve to production ratio stands at 41 to 57 years, a ratio that has not reduced over time despite the fact that production rates were increasing every year. Looking at past exploration success rates, the chances are good that proven reserves will increase in the future with further gas exploration.

Natural gas pipelines provide the necessary infrastructure to move gas from the field to the market. For almost two decades now, in the absence of extensive pipeline networks, most of Southeast Asia's natural gas resources had been regarded as a commodity for export to Northeast Asia (Japan, Korea and Chinese Taipei) earning substantial foreign exchange instrumental for the overall economic development of regional economies. Through LNG exports Southeast Asia's natural gas resources have for about two decades been contributing more to the energy supply security of Northeast Asia than to that of its own region. Pipeline infrastructure is a pre-requisite for Southeast Asia's natural gas to be consumed more domestically and play a greater role in the energy supply security of the region.

NATURAL GAS USE IN MITIGATING CLIMATE CHANGE

CO_2 is the single most important anthropogenic greenhouse gas, and fossil fuel production and utilisation cause about three-quarters of man-made CO_2 emissions. Wider use of natural gas, especially in the power sector, can play a double role in mitigating global climate change. On the one hand, as shown in Table 1, gas emits the least amount of CO_2 to the atmosphere compared to other fossil fuels, and on the other hand it facilitates energy efficiency improvements as combustion technologies improve.

The availability of domestic gas pipeline networks will enable natural gas to penetrate more into the electricity and non-electricity sectors, enabling Southeast Asia to share some of the responsibility, along with the developed economies, in mitigating global greenhouse gas emissions, while enhancing regional environmental security at the same time.

SHARING OF RESOURCES AND ENCOURAGING OF INTRA-TRADING

Southeast Asia consists of different groupings of economies in terms of energy resources. On the one hand, a number of economies (such as Brunei Darussalam, Indonesia, Malaysia and Myanmar) are gas exporters, possessing more than adequate reserves to meet domestic demand. On the other hand, Singapore is not endowed with indigenous energy resources, and natural gas is a much-needed energy commodity for the economy to balance its dependency of oil. Other economies like Thailand are also endowed with some natural gas reserves but high local demand compels the economy to import additional supplies from a neighbouring economy. This complementarity between exporting and importing economies could well be achieved through pipeline interconnection as LNG is not economically viable for short distance transportation.

Even in the gas producing economies, the commodity is not well distributed within their geographical boundaries. In many cases pipeline infrastructures are developed for the main purpose of supplying gas to major market areas, which usually means to or near the capital cities, or near the gas processing areas serving the immediate community, hence depriving smaller markets in other locations. A more integrated and widespread pipeline network is a necessity for natural gas to be more accessible across an economy.

Sharing of resources across borders will enhance more energy commodity trading between member economies in Southeast Asia. Although the ASEAN Energy Cooperation agreement was signed in June 1986 to try and promote energy cooperation in all aspects of the energy industry in the region, intra-trading of oil, coal and the gas among the economies is still in its infancy. Energy commodities are traded outside the region more than they are within. With the oil industry maintaining a relatively static position (due to energy policies attempting to reduce the focus on oil), and further utilisation of coal in the near future still debatable due to its less environmentally-friendly characteristics, natural gas has a natural advantage for intra-trading.

ENHANCING THE SUPPLIES INDUSTRY AND CAPITAL INVESTMENT

The linking of gas pipelines across borders would enable economies to make more efficient use of existing capital investment in energy infrastructure to utilise the gas in various sectors.

Although natural gas production started in Southeast Asia as early as the 1980's the industry is dominated by LNG which is geared for export. Utilisation of natural gas for domestic purposes is still considered as a recent possibility. The lack of market competition in the domestic natural gas industries in Southeast Asia is primarily a reflection of their relative infancy. The transition of the natural gas industry from being government regulated to open market competition, and from export oriented to being focused on domestic markets will be a process that goes in tandem with the overall economic growth of the region.

While acknowledging that certain energy economies are saddled with specific social objectives, natural gas is now trending towards market-based pricing in Asian markets. With most natural gas exploration and supply development projects being financed and initiated by the private sector, it is anticipated that pipeline projects will also be developed by the private sector. This will eventually bring more participants in the market and increase competition. The expansion of the transmission and distribution networks, including cross-border interconnections will increase the opportunities for consumer choices and better competition in the natural gas industry.

CHAPTER 3

NATURAL GAS MARKET POTENTIAL

This chapter required much data sourcing. It is important to note that the natural gas figures for reserves, production and consumption vary from one source to another. No single reference source is complete, hence missing data in one reference may be sourced from other references. At other times the required data may be available in different sources, but are distinctly different from one another, and therefore some considerations are necessary as to their use.

Gas reserves, production and consumption analysis relies heavily on the BP Amoco Statistical Review of World Energy, June 1999 (BP Amoco, 1999) as this publication provides quite a comprehensive list of statistics covering other energy sources. However, not all Southeast Asian gas-producing economies are listed in this publication. For reserves, CEDIGAZ figures are more popularly used worldwide – and they are more optimistic than BP Amoco's figures. Official figures either released by the related ministries or the national oil and gas companies (NOGCs) are also sometimes available and these may again vary from BP Amoco or CEDIGAZ's figures. In this report, where available, official figures are widely used.

Units used in this report are generally metric especially for reserves, production, export, import and pipe flow capacities. LNG quantities are usually expressed in tonnes. Gas consumption figures are expressed in either metric units or in million tonnes of oil equivalent consumption (Mtoe) - use of Mtoe facilitates comparison with the other primary sources of energy such as oil and coal, and with secondary sources such as electricity. Pipeline distances are specified in kilometres but pipeline diameters are generally stated in inches, and in this report the diameters are stated in their original description, in inches. For all other quantities the conventional units are used.

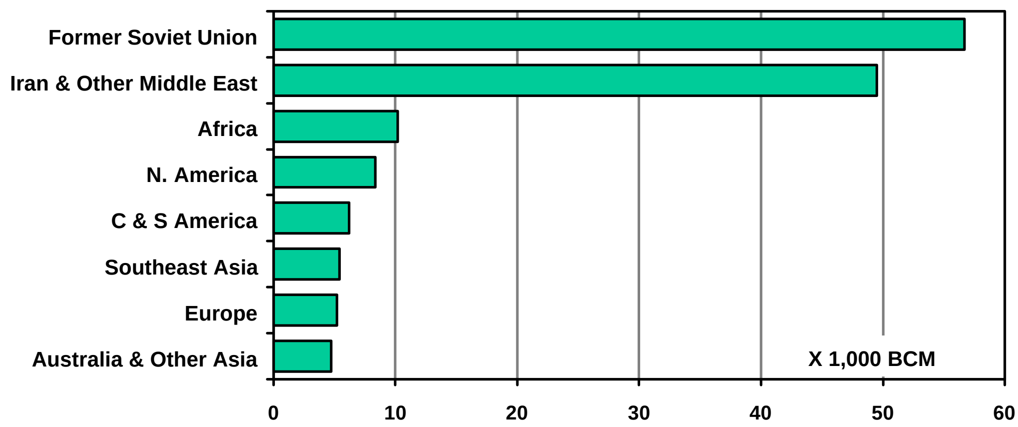
NATURAL GAS SUPPLY POTENTIAL AT REGIONAL LEVEL

In terms of global ranking, Southeast Asia's proven reserves rank sixth, as shown in Figure 2. The information below is based on BP Amoco's reserves as of 1 January 1999. On a national basis, Russia has the highest proven reserves in the world, at 48,140 BCM (BP Amoco, 1999). Southeast Asia has total proven reserves of 5,620 BCM, one/tenth that of the FSU.

The proven reserves estimates provided by BP Amoco for Southeast Asia are actually on the pessimistic side. Table 2 shows the proven gas reserves of Southeast Asia as provided by different sources, namely, official sources, BP Amoco, and CEDIGAZ. Figures designated as official sources are mostly derived from the ASEAN Energy Bulletin published by the Jakarta-based ASEAN Centre for Energy (ACE), and provided by senior officials of the respective member economies (ACE, 1999). Other figures in this column are quoted from other sources as provided or published by senior executives of the respective national oil and gas companies (NOGCs).

The three different sets of figures given in Table 2 are reserves as of 1 January 1999. The June 1999 version of BP Amoco Statistical Review of World Energy provides the latest proven reserves of only five member economies, namely: Brunei Darussalam, Indonesia, Malaysia, Thailand and Viet Nam. Reserves for the Philippines and Myanmar are therefore reproduced from the member economies' figures. CEDIGAZ figures are more complete – all seven natural gas producing economies are included.

Figure 2 Southeast Asia's natural gas position with respect to rest of world



Source: BP Amoco, 1999

It is interesting to note that CEDIGAZ's figures are more optimistic than BP Amoco's figures. CEDIGAZ's total reserves are 33 percent higher than "official figures" total reserves and 40 percent higher than BP Amoco's total reserves. While the corresponding figures are fairly comparable, the major difference comes from CEDIGAZ's estimate of the Indonesian reserves which is 92 percent higher than the official estimate, and slightly more than double that of BP Amoco's proven reserves for Indonesia. In general CEDIGAZ's figures are higher than the figures published by individual economies, except for Thailand. On the other hand BP Amoco's reserves for the five economies are lower than official figures for the corresponding economies.

Table 2 Proven natural gas reserves in Southeast Asia

Economy	1 January 1994[1] (BCM)	1 January 1999		
		Official Sources[2] (BCM)	BP Amoco (BCM)	CEDIGAZ (BCM)
Brunei Darussalam	226	392	390	382
Indonesia	1,967	2,156	2,050	4,150
Malaysia	1,270	2,402	2,310	2,480
Philippines	58	110	(110)	161
Thailand	175	420	350	220
Viet Nam	-	220	190	195
Myanmar	-	220	(220)	285
TOTAL	3,696	5,920	5,620	7,873

Source: 1) AEEMTRC, 1996

2) ACE, 1999; GASEX, 1998; IEA, 1999

As seen from Table 2, using official figures as a reference, Malaysia in 1999 had the highest reserves, at 2,402 BCM, with Indonesia closely behind at 2,156 BCM. The situation was the reverse in 1994 – Indonesia was leading with a proven reserve of 1,967 BCM with Malaysia at 1,270 BCM. As a matter of fact, during this five-year period Malaysia's NOGC, PETRONAS had undertaken a lot of exploration – with good results. Within five years Malaysia's proven reserves had doubled, although during this period production had increased yearly, mostly due to higher utilisation of natural gas domestically in combined cycle power plants introduced by the state-owned power utility company, Tenaga Nasional Bhd, and independent power producers (IPPs).

Thailand's reserves were third highest, with 420 BCM, exceeding Brunei Darussalam at 392 BCM. Thailand's reserves had significantly increased especially from the gas fields in the Malaysia - Thailand Joint Development Area (JDA). Myanmar and Viet Nam have proven reserves of around 220 BCM, and the Philippines the least at around 110 BCM.

The second column in Table 2 provides proven reserves as of 1 January 1994 to indicate that during the five-year period from January 1994 to January 1999 reserves had actually increased rather than decreased, in spite of increased production output during this period. The increase has resulted from the firming up of estimates of known resources, or improved assessments of certain resources, or more gas field discoveries following concerted exploration.

Table 3 provides estimates of total potential resources for the seven economies with the addition of Cambodia. The statistics for proven reserves are recopied from Table 2 for easy comparison with the statistics for estimates of total reserves or resources. The exact term used in Table 3 for the potential reserves or resources is exactly as quoted by the government authority or the national oil and gas company (NOGC) of the respective economies. The last column of this Table indicates the percentage of proven reserves to that of total resource estimates. These percentages do give some assurances that the proven reserves may increase in the future with more exploration, just as has happened in the past years.

Table 3 Southeast Asia's natural gas reserves and resources

Economy	Proven reserves (Official sources) (BCM)	Total reserve or resource estimates (BCM)		Proven reserves as percentage of resource estimates
Brunei Darussalam	392	-		-
Indonesia	2,156	3,864	(total reserves)	55.8%
		8,312	(gas resources)	25.9%
Malaysia	2,402	2,402	(total reserves)	-
Philippines	110	952	(total potential reserves)	11.6%
Thailand	420	590	(total reserve)	71.2%
Viet Nam	220	1,260–1,740	(prospective reserves)	15.0%
Cambodia	-	280	(total reserves)	-
Myanmar	220	742	(total reserves)	29.6%
TOTAL	5,920	9,920–10,400	(total reserves)	58.3%

Source: ACE, 1999; GASEX, 1998, IEA, 1999

Table 4 shows the proven reserve-to-production ratio based on the total reserves reproduced from Table 2. Total production of natural gas in Southeast Asia for 1993 was 106.4 BCM (excluding Viet Nam and Myanmar) (AEEMTRC, 1998). It will be shown later in this Chapter that total production for 1998 for the region was 136.4 BCM. It is interesting therefore to note that the reserve-to-production ratio had actually gone up from 34.7 in 1994 to 47.4 in 1999 taking the average of three figures for 1999.

Table 4 Proven reserve-to-production ratio in 1994 and 1999

Economy	1 January 1994	1 January 1999		
		Member Economies	BP Amoco	CEDIGAZ
Total Reserves (BCM)	3,696	5,920	5,620	7,873
Previous Year Production (BCM)	106.4[1]	136.4[2]		
Reserve-to-Production Ratio	34.7	43.4	41.2	57.7

Sources : (1) AEEMTRC, 1998.
(2) BP Amoco, 1999

The next section provides more information on natural gas reserves and production activities at economy level.

SUPPLY POTENTIAL OF GAS EXPORTING ECONOMIES

In 1998, 52.3 percent of Southeast Asia's total natural gas production (63.6 BCM) was exported in the form of liquefied natural gas (LNG). The three Southeast Asian natural gas exporting economies are: (1) Malaysia and (2) Indonesia (with long-term supply contracts with Japan, Korea and Chinese Taipei), and (3) Brunei Darussalam (with long-term supply contracts with Japan and Korea). Of the Northeast Asian natural gas importing economies, Japan receives 44.7 BCM (70.3 percent), Korea receives 14.2 BCM (22.3 percent), and Chinese Taipei receives 4.7 BCM (7.4 percent). The LNG exports from Southeast Asia corresponded to 56.2 percent of total global LNG trade movements in 1998.

In 1998, Myanmar became Southeast Asia's fourth natural gas exporter when it started a small delivery of gas by long-distance pipeline to Thailand to fuel power plants at Ratchaburi. Meanwhile, since the completion of the second phase of the Peninsular Gas Utilisation (PGU II) pipeline project in 1992, Malaysia has been exporting 1.55 BCM per year of natural gas through pipeline to Singapore.

Below are some highlights on the production activities of the gas exporting economies which are derived from BP Amoco Statistical Review of World Energy 1999 (BP Amoco, 1999), and supplemented by various other sources.

BRUNEI DARUSSALAM

Current proven reserves at 390 BCM in 1999 are a significant increment from those of January 1994 (226 BCM). This is a proven reserve increase of 72.5 percent over a five-year period.

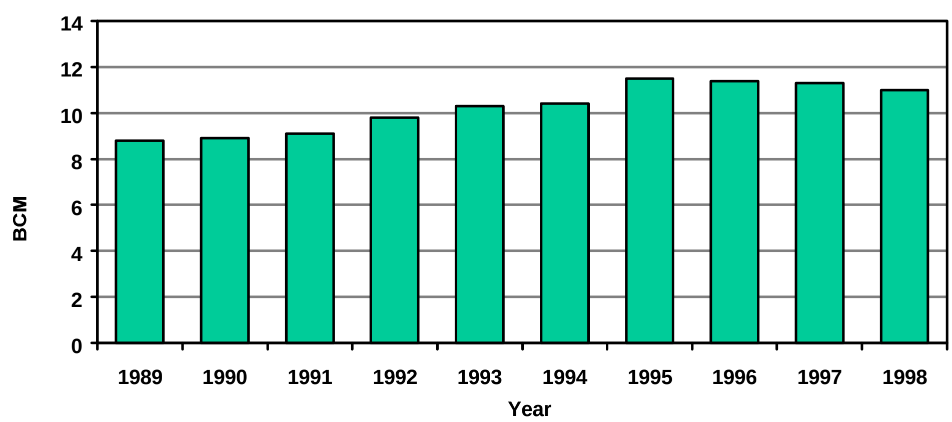
From January to June 1998, Brunei Darussalam exported 3.77 BCM of natural gas (88.94 percent of export) to Japan and 0.46 BCM (11.06 percent) to Korea. Under a Sale and Purchase Extension Agreement signed between Brunei Liquefied Natural Gas (BLNG) and the Japanese buyers in 1993, the LNG Plant at Lumut agreed to export annually about 5.54 million metric tonnes of LNG to Japan. In June 1998, an amendment was made to this agreement, known as the Sale and Purchase Extension Agreement Amendment. With this amendment an additional 14 cargoes per annum would be exported to Japan starting from 1999 until the year 2013.

In October 1997, a sale and purchase agreement had also been signed to deliver 0.7 million metric tonnes of LNG to Korea until the year 2013. In total, 200 'B' class LNG cargoes equivalent will be delivered annually to the buyers in Japan and Korea from the year 1999 to 2013.

With this export capacity, Brunei Darussalam ranks as the world's fifth largest exporter of liquefied natural gas (LNG) after Indonesia (36.1 BCM), Algeria (24.9 BCM), Malaysia (19.4 BCM) and Australia (9.9 BCM) (BP Amoco, 1999). Oil and Gas accounted for about 36 percent of the economy's Gross Domestic Product (GDP) in 1996. A brief glance at its past indicates that Brunei Darussalam has successfully diversified its economy by cutting down high oil and gas contributions to GDP from 88 percent in 1974 to 58 percent in 1990, and down further to 36 percent in 1996 (Brunei Darussalam government website). The policy to conserve its natural resources and diversify further its contribution to GDP, was initiated in 1988.

Figure 3 shows Brunei Darussalam's annual growth of natural gas production for the past ten years, reflecting an average annual mean growth of 2.3 percent. Between 1989 and 1998, there had been no new export contracts to Japan and Korea – hence this small annual growth is mainly to cater for the additional increase in domestic consumption. Extended contracts commitment with Japan and Korea will be in effect from the year 1999 until 2013.

Figure 3 Brunei Darussalam's natural gas production (1989 – 1998)



Source: BP Amoco, 1999

INDONESIA

Indonesia's latest proven natural gas reserve estimate is officially quoted at 2,156 BCM. BP Amoco's reserve estimate for Indonesia is lower by about 5 percent from the official figure, but CEDIGAZ's estimate is almost double than the official figure.

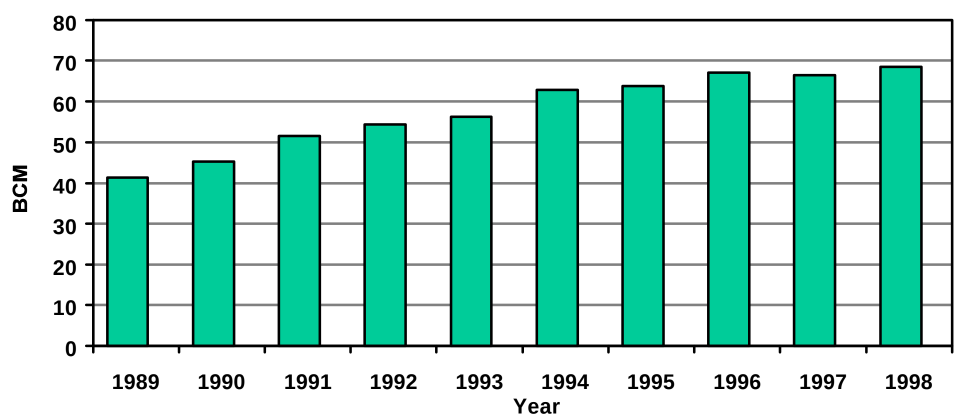
This reserve includes the Natuna D-Alpha field that holds 1,260 BCM of recoverable gas. While this natural gas source is poised to be the main future supplier of pipeline natural gas to nearby Southeast Asian economies, agreements for the development of the field may take a considerable time to reach. The primary reason is its remoteness and the costs of separating the high carbon dioxide content from the extracted gas. The Natuna D-Alpha gas price to consumers may end up being higher than gas from other sources in the region.

The recent discovery of high quality natural gas reserves by ARCO and British Gas in the Berau, Wiriangar and Muturi blocks, commonly known as the Tangguh gas fields in Berau Bay, West Irian Jaya, with proven reserves of 403 BCM will change the scenario of Indonesia's gas flow chain (Sjahrial, 1998). However, being located very far from the nearest demand centres, it seems very unlikely that this gas will be transported to other demand areas in Indonesia, such as Java and Bali, by pipeline.

Indonesia ranks first in Southeast Asia as a natural gas, oil and coal producer. Gas production in 1998 amounted to 68.4 BCM, 46.8 percent of which was consumed domestically. With no cross-border pipeline yet in existence all exports are as LNG, shipped to Japan (24.2 BCM), Korea (9.5 BCM) and Chinese Taipei (2.4 BCM) – through long-term supply contracts. Most of the domestic consumption is used to fuel gas turbines and the more recently developed combined cycle power plants using gas transported by independent local pipeline networks.

Figure 4 indicates Indonesia's natural gas production from 1989 to 1998. Over the ten-year period, natural gas production has been growing at an average rate of 5.2 percent. In 1997 however, there was a drop in production, obviously due to reduced demand resulting from the negative impact of the economic crisis (falling from 67.1 BCM in 1996 to 66.4 BCM in 1997). Production in 1998 just exceeded the 1996 figure by a small margin.

Figure 4 Indonesia's natural gas production (1989 – 1998)



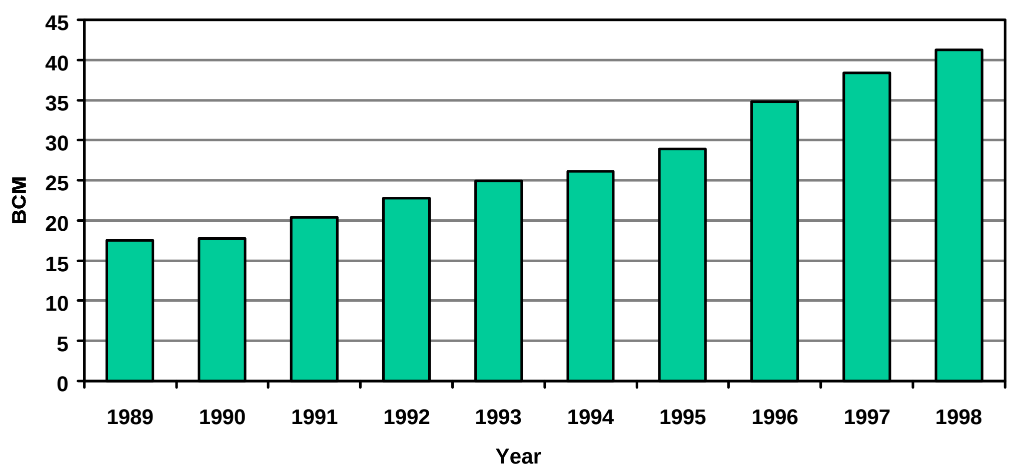
Source: BP Amoco, 1999

MALAYSIA

PETRONAS, Malaysia's state-owned oil and gas company has had good success with gas exploration projects. To date more than 214 gas fields have been discovered in Malaysia but only 10 have been developed and are producing (PETRONAS website). Several more are under development. Malaysia's proven reserves have risen from 1,270 BCM on 1 January 1994, to 2,310 BCM on 1 January 1999, despite an increase in production capacity over this period. At the 1998 production capacity level of 41.3 BCM, Malaysia's supply of natural gas would last for the next 56 years. Based on 1998 export figures of 19.4 BCM of natural gas exports, Malaysia was Southeast Asia's second biggest exporter of LNG, after Indonesia. Malaysia's export destinations are Japan (68.0 percent), Korea (20.1 percent) and Chinese Taipei (11.9 percent).

Over a period of ten years from 1989 to 1998, Malaysia's natural gas production has increased by more than two times, from 17.5 to 41.3 BCM, respectively (see Figure 5). This is an average increase of 9 percent per year, and with no new export commitments, most of the extra production capacity per year is to meet domestic demand, especially as fuel for the new power plants operated by independent power producers (IPPs). The corporatised national utility company, Tenaga Nasional Berhad is also continuously upgrading its oil fired power plants to combined-cycle gas-turbines to increase its generation efficiency and to remain cost competitive with the new emerging IPPs.

Figure 5 Malaysia's natural gas production (1989 – 1998)



Source: BP Amoco, 1999

MYANMAR

To date, Myanmar has been producing natural gas from around 10 onshore gas fields, with a current total proven reserve of 13.4 BCM. Its current production output stands at 4.95 million cubic metre per day (MMCMD) and at this rate of production the on-shore reserves would be dry in less than 8 years. All on-shore production is targeted at local markets.

Myanmar's total gas reserves are estimated at 742 BCM (ACE, 1999). Total proven reserves are stated at 220 BCM (IEA, 1999). Since the enactment of the Foreign Investment Law in 1988, the Ministry of Energy had signed over 40 petroleum exploration and production contracts with multinational companies. As a result of these exercises, the off-shore Yadana and Yetagun fields were explored and developed, making these two fields Myanmar's major gas-producing fields.

The Yadana and Yetagun gas fields have proven reserves of 161 BCM and 47.6 BCM, respectively. Both fields are located in the Andaman Sea, the first about 80 km south off the southern coast of Myanmar, and the latter about 140 km further south. The Yadana field is about 400 km west of the Thai border, whereas the Yetagun field is closer, about 170 km west of the border.

These two gas fields will be important in bringing in foreign currency, as they are dedicated to export markets, except for the diversion of about 20 percent of production from the Yadana field (3.54 MMCMD) for domestic consumption. With on-shore fields depleting, Myanmar will have to rely increasingly on new offshore discoveries in the future.

Under the 30-year gas sales agreement with Thailand, the first Yadana gas exports were scheduled to be delivered to the Petroleum Authority of Thailand (PTT) on 2 July 1998. However, due to the economic crisis in Thailand and the delay in the full completion of the Ratchaburi power plant, PTT was only able to take 0.14 MMCMD, well below the 1.82 MMCMD in the agreement. Under the "take or pay" agreement PTT is obligated to pay for the full 1.82 MMCMD. However, Thailand will not lose the undelivered gas, the amount not delivered in the short-term will be delivered at a time when Thailand can take the gas.

SUPPLY POTENTIAL OF GAS CONSUMING ECONOMIES

Thailand and Viet Nam have been producing natural gas for many years, but their expanding economies, and policies to diversify fuels used in power generation have meant that natural gas production has been totally consumed domestically. The Philippines is also concentrating on developing its own natural gas resources with the intention of consuming the gas domestically.

THE PHILIPPINES

The Philippines gas resources range between 252 - 756 BCM. Proven reserves from five gas fields account for 84 - 112 BCM. The biggest reserve so far is the Camago-Malampaya field in offshore Northwest Palawan with at least 70 BCM of recoverable gas. Other gas fields are the San Martin (4.48 - 8.4 BCM) and the Ocotn (19.6 BCM) in northwest Palawan, the San Antonio (0.056 BCM) in Cagayan and the Libertad (0.084 BCM) in Cebu (DOE, Philippines).

The Philippines' current supply of natural gas comes from the small San Antonio gas field which fuels a 3.25 MW power plant. This onshore field in Luzon Island, north of Manila, has been producing natural gas since 1994, with a volume capacity of 6.54 MMCM in 1995, 6.32 MMCM in 1996, 5.69 MMCM in 1997 and 9.2 MMCM in 1998. The current volume of gas production is about 0.028 MMCMD (DOE, Philippines).

In an unsuccessful attempt to find oil, the Camago-Malampaya gas field was discovered in August 1989 by an exploration company belonging to Occidental Philippines Inc. (Oxy). At that time proven reserves were only about 28 BCM. A subsequent study made by Arthur D. Little established that any project to bring the gas in this field to Luzon Island would be only economically viable if the total reserves were at least 112 BCM. This is because of the high cost of the deep-water project (800 m) and the long distance from the market in Luzon (500 km). Oxy entered into a 50:50 joint-venture with Shell Philippines Exploration BV (Shell Philippines) but later Oxy and Shell Philippines agreed to an asset swap for other upstream projects, giving Shell a 100 percent share of the Camago-Malampaya project (Chua, 1998).

More exploration work so far had resulted in the confirmation of at least 70 BCM of recoverable gas in the Camago-Malampaya complex. In addition, 26 million barrels of recoverable oil and 59 million barrels of condensate have been proven and there is potential to expand the gas reserves to more than 112 BCM with more exploratory work.

The Philippines' Energy Plan 2000 – 2008 projects the following indigenous gas production as shown in Table 5.

Table 5 Projected natural gas production in the Philippines (2000 – 2008)

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008
Production (BCM)	0.014	0.018	4.153	4.153	4.153	4.153	4.153	4.149	4.135

Source: DOE, Philippines

The production from the Malampaya gas field is programmed to come on-stream in 2002 to fuel 2,700 MW of base-load power generation capacity. Gas demand for power generation will start from 2.72 BCM in 2002 and will reach 3.33 BCM in 2004. The plan envisions the use of gas by the industrial and commercial sectors starting in 2005. Other potential applications of natural gas could possibly be realised beyond 2008. With current proven reserves estimated at 84 – 112 BCM (3 - 4 TCF) vis-à-vis the anticipated increasing demand for gas, the Philippines will need to engage in more exploration, or look at importing from neighbouring member economies, either as LNG or through the proposed TAGP network.

THAILAND

Thailand is endowed with some reserves of oil, natural gas and coal to support the economy's policy of self-sufficiency in energy production. The economy has estimated natural gas reserves of 420 BCM, about 94 percent of which is found in the Gulf of Thailand. Major gas fields are the Malaysia - Thailand Joint Development Area (MT-JDA) with 171 BCM, Bongkot with 90 BCM, and Pailin-Moragot with 33.6 BCM. Three other fields that have begun to produce gas are Tantawan, Pladang and Plamuk with production capacity of up to 2.52, 1.09 and 0.34 million cubic metres per day (MMCMD), respectively (ACE, 1998).

Gas production in Thailand started in 1981 after the Petroleum Authority of Thailand (PTT) was assigned the job of accelerating procurement of natural gas both from concessionary resources in the Gulf of Thailand and from foreign imports. Since then production has increased from 26.3 MMCMD in 1993 to 47.6 MMCMD in 1998, corresponding to an average annual increase of 12.6 percent per year for five years (ACE, 1999).

With insufficient supply to meet increasing demand, Thailand had planned to import natural gas from Myanmar. Through the Yadana – Ratchaburi pipeline, a small amount of gas was imported in 1998, and is expected to increase to 12 MMCMD in 2000 when the Ratchaburi power plant in Thailand is fully completed. Although the power plant is not fully completed, some gas turbines will be operating by late 1999. Meanwhile, through the take-or-pay contract agreement between EGAT, PTT and the Myanmar gas suppliers, PTT is already paying for the undelivered gas, with the unconsumed gas supplied later when Thailand's side is ready for full consumption of the gas.

Another 2.9 MMCMD is expected from Myanmar, from the Yetagun gas field later in the year 2000 (IEA, 1999).

VIET NAM

For many years Viet Nam's primary energy supply came from oil, coal and hydropower, in that order. It was only in 1981 that natural gas came into the energy scenario, when a small onshore field near Hanoi, with an initially estimated reserve of about 1.3 BCM, started producing natural gas to fuel a 35 MW power plant.

BP Amoco recorded Viet Nam's proven reserves at 190 BCM as of 1 January 1999. The Viet Nam government's data indicates 220 to 320 BCM, and a potential (prospective) reserve of 1,260 to 1,740 BCM.

The offshore Bach Ho (White Tiger) field, is to date Viet Nam's biggest natural gas reserve, estimated at 170 to 230 BCM. Bach Ho is an oil field and the gas found is associated gas, where previously close to 1 BCM per year had to be flared due to lack of infrastructure to utilise the gas (IEA, 1999).[1] It was only in 1995, when infrastructure was completed, that the associated gas produced began to be utilised.

The Nam Con Son reserves, first discovered in 1993, are now estimated at between 532 and 700 BCM, with proven reserves placed at 196 BCM. Nam Con Son is a non-associated gas field.

PetroVietnam, in its Gas Masterplan prepared in 1995, indicated proven gas reserves of 340 to 510 BCM, and with potential resources amounting from 1,670 to 2,240 BCM. The plan also included Viet Nam's gas demand outlook which estimated a natural gas demand of 4.0 to 9.0 BCM per year until the year 2000, increasing to 10.0 to 16.0 BCM per year until the year 2005 and increasing further to 16.0 to 21.5 BCM per year until the year 2010 (Nguyen, 1998).

A linear interpolation made between the years provided indicates that Viet Nam will need a total gas reserve of 140 BCM for its domestic needs from 2000 to 2010. Its current proven reserves of 220 BCM is more than sufficient to meet its demand in this decade. With its current proven reserves totalling only about 15 percent of its prospective resources, chances of Viet Nam finding more proven reserves and even joining its other neighbours as a gas exporter (fourth gas exporter in the region) is high if the government policy encourages more aggressive gas exploratory exercises.

OVERVIEW OF NATURAL GAS CONSUMPTION

Before the financial crisis, in the period 1990 – 1996, the annual GDP growth rate of the region was 7.4 percent while the annual average growth rate in primary energy consumption for five economies (Indonesia, Malaysia, Philippines, Singapore, and Thailand) was 8.5 percent.[2] The total primary energy consumption of these economies in 1996 was 220.9 Mtoe. The share of oil, gas, hydroelectric, and coal accounted for 65.16, 24.7, 1.09, and 9.05 percent, respectively, of total energy consumption. During 1995 to 1996, by fuel type, coal presented the highest growth rate at 30.7 percent, then natural gas at 10 percent and finally oil at 5.5 percent. The summary of these data is shown in Table 6.

1 By comparison, the quantity of this flared gas was about 64 percent of Malaysia's annual pipeline gas exports to Singapore

2 The Energy Data Modeling Centre, The Institute of Energy Economic, Japan

Table 6 Primary energy consumption by fuel in Southeast Asia (1990-1996)

Fuel Type	Primary Energy Consumption (Mtoe)							% Growth Rate	% Share
	1990	1991	1992	1993	1994	1995	1996	1991-1996	1996
Coal	10	11.2	11.3	12	13.3	15.3	20	12.2	9.0
Oil	94.2	99.2	108.1	117.1	125.9	136.4	143.9	7.6	65.2
Natural gas	29.7	33.9	37.6	42.2	46.9	49.8	54.6	12.0	24.7
Hydroelectricity	1.7	1.7	1.9	1.8	2.1	2.3	2.4	5.9	1.1
TOTAL	135.6	146	158.9	173.1	188.2	203.8	220.9	8.5	100

Source: BP Amoco, 1999

Note: Indonesia, Malaysia, Philippines, Singapore and Thailand only.

The situation in the developing economies in Asia has changed dramatically since the last half of 1997 in the wake of the recent financial crisis in which Indonesia, Thailand and Malaysia were badly hit. Currencies that were linked to the appreciating US dollar aggravated economic problems and contributed to further economic destabilisation.

The effects of the financial crisis in Asia have slowed the region's GDP growth between 1998 and 2000 (APERC, 1998). The crisis caused a temporary setback to the growth of energy consumption. The total primary energy consumption in 1998 fell by 2 percent from the previous year, of which coal and oil consumption declined by 10 and 5 percent respectively, however gas consumption increased by 9.1 percent (see Table 7).

Table 7 Primary energy consumption by fuel in Southeast Asia (1997-1998)

Fuel Type	Primary Energy Consumption (Mtoe)		Percentage Growth
	1997	1998	(1997-1998)
Oil	151.9	144.6	-5.0
Natural Gas	57.4	62.6	9.1
Hydro Electricity	20.7	19.1	-8.4
Coal	2.2	2	-10.0
TOTAL	232.1	228.4	-2.0

Source: BP Amoco, 1999

Note: Indonesia, Malaysia, Philippines, Singapore and Thailand only.

DOMESTIC USE OF NATURAL GAS IN SOUTHEAST ASIA

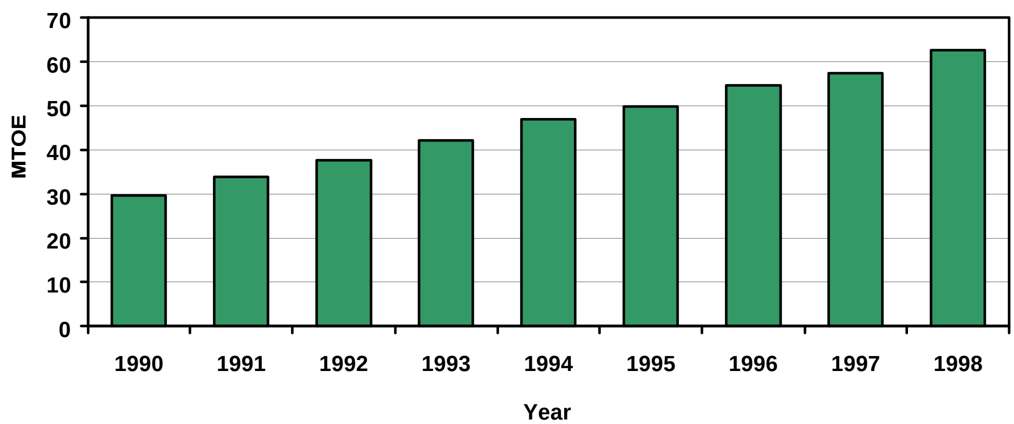
In 1996, the nine economies of Southeast Asia, namely; Brunei Darussalam, Indonesia, Malaysia, the Philippines, Singapore, Thailand, Myanmar, Lao PDR and Viet Nam, consumed 42.1 Mtoe of natural gas for domestic use, 34 percent of the region's total production (at 123 Mtoe).

This is a substantial increase both in terms of quantities used and percentage share for domestic use. In 1994, the six more developed economies (Brunei Darussalam, Indonesia, Malaysia, the Philippines, Singapore and Thailand - called the ASEAN-6) consumed 24 Mtoe of natural gas, 21.6 percent of the total production of 111 Mtoe. In 1985, gas consumption was recorded at 9 Mtoe - constituting 16 percent of the total regional energy consumption.

Figure 6 shows a steady increase in natural gas consumption in Southeast Asia in the period 1990 –1998, with an average increase of 9.5 percent per year. As mentioned earlier, the economic crisis did not have much impact on natural gas consumption.

The large increase in the share of natural gas in the energy demand scenario is a direct result of initiatives taken by Southeast Asian economies to cut down their high reliance on oil and oil products, as well as the region's strong awareness and concern regarding the environmental impacts of energy use. Natural gas, as a premium fuel and an environmentally friendly alternative to oil and coal, is a natural choice to take an increased share in energy markets.

Figure 6 Natural gas consumption for Southeast Asian economies (1990-1998)



Source: BP Amoco, 1999

Natural gas is mostly used in power plants, as efforts to introduce compressed natural gas (CNG) in the transportation sector are at an early stage. Brunei Darussalam, for example, has 96 percent of its power plants fired by natural gas while Malaysia, as part of its diversification policy, has now successfully transformed 60 percent of its power plants to gas-fired, compared to 98 percent oil-fired fifteen years ago. Although Viet Nam has started using associated gas for electricity generation from 1995, its share of the total is rapidly increasing (from 0.1 percent in 1995 to 10 percent in 1998).

In Indonesia, where coal is the major fuel for electricity generation, the amount of natural gas burned in power plants is comparable to its direct use in industry. Most of the natural gas consumed in the industrial sector is used as feedstock for Indonesia's fertiliser plants.

Major Southeast Asian capital cities like Bangkok, Jakarta, Manila and to some extent, Kuala Lumpur, are highly polluted, and initiatives to increase the use of natural gas in the transportation sector have encountered two main hurdles. For consumers, there is the high initial cost incurred to install the conversions kits, and for suppliers, there is a lack of comprehensive gas pipeline reticulation networks to allow dissemination of fuelling stations.

Table 8 further shows the domestic consumption of natural gas per economy by sector in 1996 for the seven APEC economies in Southeast Asia and Myanmar. The figures given in brackets are percentages of natural gas use in particular sectors. As observed from the table, electricity generation consumed almost 30 Mtoe, accounting for 71.2 percent of total natural gas consumption. Next highest is the industrial sector at 17.1 percent and the residential-commercial sector is lowest at 1.2 percent. By economy, the share of total gas consumption is 45.7 percent for Indonesia, 23.7 percent for Malaysia, 24 percent for Thailand and 8.3 percent for the rest of the economies. Further deliberation on gas use per economy is provided in the next section.

Consumption figures provided in Figure 4 are sourced from BP Amoco (BP Amoco, 1999), whereas the figures used in Table 8 are derived from AEEMTRC's ASEAN Energy Review (AEEMTRC, 1998) and from the Institute of Energy, Viet Nam. BP Amoco's total consumption (for five economies; Indonesia, Malaysia, Philippines, Singapore and Thailand) is about 31 percent higher than AEEMTRC's total (for eight economies, the earlier five plus Brunei Darussalam, Viet Nam and Philippines). AEEMTRC figures are official data provided directly by the respective agencies in each economy and their data are used in Table 8 because of available disaggregated consumption at the sub-sector level. BP Amoco, however provides more recent consumption figures (until 1998) and the following brief description of natural gas at economy level are derived using data from BP Amoco.

Table 8 Domestic natural gas consumption by sector in 1996

Economy	Electricity Production (Mtoe)	Industry (Mtoe)	Residential & Commercial (Mtoe)	Fertilisers & Others Mtoe)	Total (Mtoe)
Brunei Darussalam	0.667 (96.0%)	0	0.028 (4.0%)	0	0.695
Indonesia	10.912 (56.8%)	4.783 (24.9%)	0.023 (0.1%)	3.487 (18.2%)	19.205
Malaysia	7.489 (75.2%)	1.197 (12.0%)	0.403 (4.0%)	0.874 (8.8%)	9.963
Philippines	0.0056 (100%)	0	0	0	0.0056
Singapore	1.165 (100%)	0	0	0	1.165
Thailand	8.466 (90.0%)	0.935 (9.9%)	0	0.005 (0.1%)	9.406
Myanmar	1.009 (77.1%)	0.22 (16.8%)	0.001 (0.1%)	0.079 (6.0%)	1.309
Viet Nam	0.276 (100%)	0	0	0	0.276
SE-Asia	29.984 (71.3%)	7.137 (17.0%)	0.455 (1.1%)	4.445 (10.6%)	42.024

Source: AEEMTRC, 1998; IE-Viet Nam

NATURAL GAS CONSUMPTION BY ECONOMIES

BRUNEI DARUSSALAM

Natural gas is by far the largest source of energy used in Brunei Darussalam and is primarily consumed as fuel for generation of electricity, the production of LNG by the Brunei LNG plant (BLNG) and for oil and gas production by the Brunei Shell Petroleum (BSP). Consumption of gas by residential and commercial sector is minimal and is mainly for cooking. Since June 1998, out of the 11 BCM of natural gas produced by Brunei Darussalam, 8.1 BCM was exported as LNG and only 2.9 BCM (26.4 percent) was used domestically (Damit, 1998).

INDONESIA

In Indonesia, total gas production was 68.4 BCM in 1998. Of this, 53 percent or 36.1 BCM was exported as LNG to Japan, Korea and Chinese Taipei. Domestic gas consumption was 31.9 BCM accounting for 10 percent of the economy's total final energy demand. This breaks down to 99.4 percent consumption by the combined electricity and industrial sector, about 0.17 percent by the household sector, and 0.43 percent by the transport sector.

MALAYSIA

In 1998, of the 41.3 BCM of natural gas production, 20.4 BCM (49.4 percent) was consumed domestically. Peninsular Malaysia owes its high domestic consumption to the Peninsular Gas Utilisation (PGU) pipeline network that began to be built in the early 1990's. The entire PGU system now spans 1,420 km, comprising main transmission pipelines, supply pipelines and laterals.

Malaysia has been successful in cutting down its high oil dependence for electricity generation. Domestic consumption is for fuelling recently installed combined-cycle power plants. Malaysia has increased its natural gas share of electricity production to 56 percent, surpassing oil consumption, the dependence on which was 95 percent in 1985. New combined-cycle power plants introduced by the corporatised state-own power utility company, Tenaga Nasional Berhad (TNB) and by independent power producers (IPPs) have been responsible for this drastic change.

Non-power consumers account for 12 percent of total gas consumption in the Peninsular and they comprise the energy intensive industries such as steel mills, small and medium scale industries, and residential-commercial sectors. The use of gas in these two sectors (industrial and residential-commercial) had increased almost 12-fold from 0.34 MMCMD in 1991 to 3.9 MMCMD in 1997/98.

MYANMAR

In Myanmar in 1997, total consumption of natural gas was 1.63 BCM, broken down as follows: 69 percent for power, 16 percent for industry, 10 percent for raw materials and 5 percent for transport and other uses.

Of the 1,393 MW total installed electricity capacity in Myanmar in 1997, the state-owned utility company, Myanmar Electricity Power Enterprise (MEPE) managed 1030 MW (74 percent). Out of this installed capacity, 546 MW (53 percent) is fuelled by natural gas and 227 MW (22 percent) is from mini-hydro. The government estimates that electricity demand in Myanmar will reach an average of 15 percent growth per year in the coming years, and this high demand will be met by hydro-power and natural gas fired plants.

The government has plans to build one 320 MW gas-fired plant in southern Myanmar, which will be fuelled by natural gas from the Yadana field. Part of the Yadana field gas is also being prepared to become feedstock for a planned urea fertiliser plant with an output of 570,000 tonnes per year.

PHILIPPINES

It is expected that the demand for natural gas in the Philippines will increase with the current restructuring of the electricity industry. The government envisions that the role of natural gas will increase in the future as an option to further reduce the dependence in imported oil and mitigate

CO_2 emission levels. It is believed that its environmental advantage and technological developments will make natural gas a versatile fuel for a wide range of uses. While the initial gas markets are the three new combined-cycle gas turbine (CCGT) power plants with an aggregate capacity of 2,700 MW, the government envisions to expand the use of gas to the markets, i.e., the industrial, commercial, residential, and transport sectors. To assure reliable gas supply, the government is actively promoting indigenous gas exploration in other potential areas of the economy.

SINGAPORE

The 4.2 MMCMD natural gas imported through the Malaysian PGU pipeline is consumed solely by the Senoko power plant for electricity generation. Other gas demand is met by "town gas" manufactured by PowerGas Ltd and supplied through its 2,300 km pipe reticulation network (about 40 percent of demand), and by liquefied petroleum gas (LPG) in bottles supplied by oil companies like Shell, Mobil and Esso (about 60 percent of demand), marketed through their chain of retail outlets. The town gas and the LPG are predominantly used for cooking and in the commercial sector. Very little gas is used for industrial purposes due to the easy availability of cheaper substitutes such as fuel oil, diesel and bulk LPG.

In the future Singapore is planning to import more natural gas in the form of piped gas or LNG to increase the gas percentage in its energy mix for power generation. Natural gas or LNG as a feedstock or for direct reticulation through the pipeline network is also being considered. Singapore has signed an agreement for pipeline gas imports of 325 million cubic feet per day (9.1 MMCMD) from Indonesia's West Natuna gas fields to start in 2001, and is contemplating pipeline gas imports from Sumatra.

THAILAND

Total gas consumption in Thailand in 1998 amounted to 16.75 BCM. Of this amount, 80 percent was consumed by the power sector, 6 percent was used as fuel in the industrial sector, and the remaining 14 percent used as feedstock for the four existing gas separation plants (GSP) which separate the gas into methane, ethane, propane, liquefied petroleum gas (LPG) and natural gas liquid (NGL). Methane is used as a feedstock for chemical fertilisation, ethane and propane are used as feed-stocks in the first stage of petrochemical industrial processes, LPG is used as a household and vehicular fuel, and NGL is directed to local oil refineries for further processing into refined oil products and then used as a feedstock in second stage petrochemical processes (Yamboonruang, V, 1998).

VIET NAM

All gas produced in Viet Nam is used to meet domestic demand – and this demand substantially exceeds production. The power generation sector is the main gas consumer. The two power plants fired by natural gas are the Baria power plant with a maximum consumption of 1.2 MMCMD, and the Phu My Phase 1 with a maximum consumption of 1.7 MMCMD. These power plants are located in the southern and more developed part of the economy (Nguyen, 1998).

The industrial zones are mostly using LPG and are waiting to switch to natural gas when it is available. In the north, the use of natural gas is negligible – being used by small local enterprises.

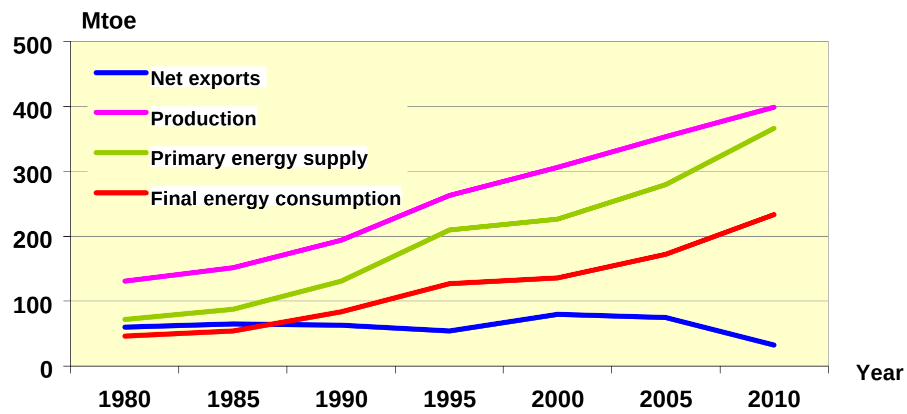
DEMAND OUTLOOK FOR NATURAL GAS FOR SOUTHEAST ASIA

In this section, APERC's APEC Energy Demand and Supply Outlook is used as the source of reference for the APEC Southeast Asian economies that were included in the outlook, namely; Brunei Darussalam, Indonesia, Malaysia, the Philippines, Singapore and Thailand (APERC, 1998). Viet Nam was not a member of APEC yet when this outlook was conducted.

Three scenarios are depicted in the outlook. The 1998 Baseline Scenario (B98) utilises GDP growth projections assuming that the Asian economies will recover from the current economic downturn in the period after 2000. The Protracted Crisis Scenario (PCS), which utilises GDP projections from the same source - the Australian Bureau of Agricultural and Resource Economic or ABARE's model, MEGABARE - is more pessimistic than B98, assuming that economic growth in the Asian region stagnates as economic fail to stimulate growth—hence resulting in a slower economic recovery in Asian economies, inducing lower rates of economic growth throughout the APEC region. The Environmentally Friendly Scenario (EFS), which also uses MEGABARE's GDP projections, assumes accelerated improvements in energy efficiency and fuel switching towards less carbon intensive energy resources.

Figure 7 shows the B98 projection on Southeast Asian economies' final energy consumption, primary energy supply, production and exports during 1980-2010 period. Historical data were used for 1980 to 1995, and the forecast period actually begins from 1995 to 2010. The Figure shows that final energy consumption in Southeast Asia increased almost three fold from 46.3 Mtoe in 1980 to 126.1 Mtoe in 1995. The projected final energy consumption during 1995 - 2000 is expected to be positive, but at a much slower pace compared to the previous period. It increases to 134.8 Mtoe in 2000, 172 Mtoe in 2005 and 232.8 Mtoe in 2010. The primary energy supply projection follows a similar trend to that of consumption, but at a higher level. It increased from 71.2 Mtoe in 1980 to 209.2 Mtoe in 1995 and is expected to increase to 366 Mtoe in 2010. The production of energy is projected to increase in an almost-straight-line trend during 1995-2010.

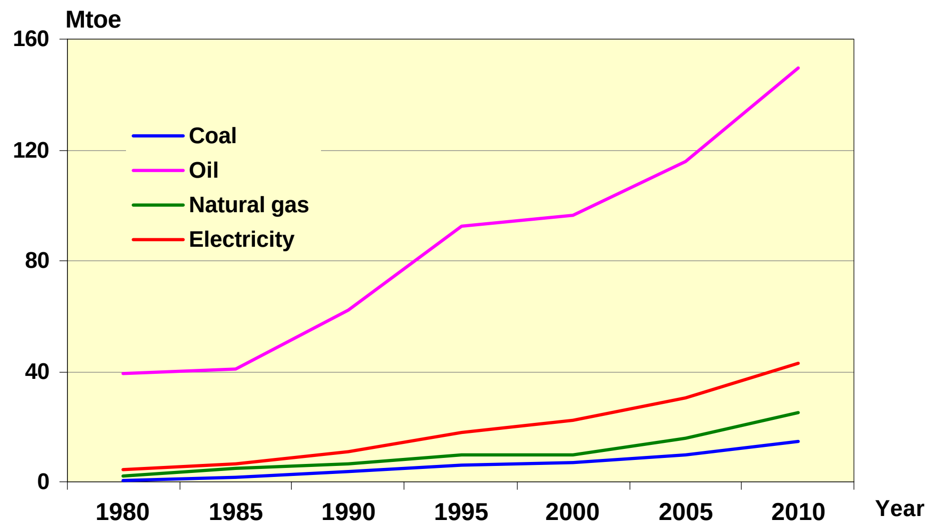
Figure 7 Southeast Asia's final energy consumption outlook (B98), (2000 – 2010)



Source: APERC, 1998

The EFS and PCS projections have similar trends. As expected natural gas consumption using the PCS scenario during 1995-2010 is lower than in the B98 projection, while in the EFS projection it is between the B98 and PCS projection.

Figure 8 Final energy consumption outlook by types of energy (B98), (2000 – 2010)



Source: APERC, 1998

Figure 8 shows final energy consumption for the B98 projection by types of energy, namely coal, natural gas, oil and electricity during the same period. Oil dominates consumption and gains a larger share in the future. However, it is influenced most by the crisis. In the period 1995 - 2000, oil consumption declines in the PCS projection, while it increases insignificantly in the B98 and EFS projection. Natural gas consumption also experiences a superficial decrease during the same period because of the crisis in the B98 and PCS scenarios, but subsequently grows especially in the EFS scenario due to its advantage in the environmental principles.

In Figure 8, the natural gas curve represents the consumption forecast for the non-electricity sector. Calculating from figures taken directly from the APEC Energy Demand and Supply Outlook, between 2000 and 2010 for the B98 projection, the average increase in consumption per year is 10.2 percent for natural gas, 8.1 percent for coal, and 4.5 percent for oil.

IMPORT POTENTIAL FROM NEIGHBOURING ECONOMIES

As observed earlier in this chapter, Southeast Asian economies can be divided into three categories with respect to natural gas: exporting, self-sufficient and importing.

Brunei Darussalam, Malaysia and Indonesia have for two decades or more been natural gas exporters, with 97.7 percent (63.6 BCM in 1998) of the gas exported as LNG to Northeast Asia. During this period, only 2.3 percent (1.5 BCM per year) of the gas exports went to a neighbouring economy, namely from Malaysia to Singapore, by pipeline. In 1998, Myanmar joined these three economies as a gas exporter - in essence it is second to Malaysia as a pipeline natural gas exporter - exporting to neighbouring Thailand. As Brunei Darussalam is keen on conserving its reserves for its own future domestic demand, and Myanmar's current proven reserves are mostly committed for export to Thailand and to meet its own increasing demand, most of future supplies for Southeast Asia may have to come from Indonesia and Malaysia.

Thailand and Singapore are two obvious importers of natural gas, both currently and in the future. The energy policies of both economies stress energy supply security, energy diversification, and environmental protection, and both have determined that natural gas is the energy alternative in pursuance of their energy policies.

Thailand for many years has been self-sufficient as far as natural gas demand is concerned. From 1998 Thailand became a net gas importer (through pipelines), despite the increasing production from its own fields and the development of the Malaysia-Thailand Joint Development Area. Thailand's usage for gas is not entirely for its power sector. While efforts are being enhanced to penetrate the use of gas in the industrial sector, natural gas is important as a feedstock for Thailand's gas separation plants, the products of which have provided significant benefits in terms of foreign exchange savings from less plastic imports, earning of foreign exchange from export of petrochemical products, stimulating downstream business, and allowing technology transfer to the Thai industry (Yamboonruang, 1998).

Thailand too, has for many years been importing hydro-electricity from Laos. Within the cooperation scheme under the Heads of ASEAN Power Utilities/Authorities (HAPUA) Thailand has plans for importing additional hydro-electricity from Laos. But as hydro projects become more and more expensive, and often become the target of environmentalists globally, the question of Laos developing further hydro-electricity projects may be in question. Pipeline gas imports have additional value-added benefits which electricity imports cannot provide. Singapore, with no indigenous energy resources, is also choosing natural gas as its second fuel, after oil. After many years of securing its natural gas from a sole provider, Malaysia, it is diversifying its import sources now from Indonesia. Natural gas consumption in Singapore has reached 1.4 Mtoe annually since 1993. This figure would increase in 2002 when the gas pipelines from West Natuna is completed. Singapore is also contemplating the import of LNG from outside the region. Sembawang Gas has been in discussion with LNG suppliers in Australia and has plans to talk to LNG suppliers in the Middle East.

The Philippines is another economy that, for several years, had been self-sufficient with respect to natural gas and will continue to be self-sufficient in the long term. Natural gas production and consumption in the Philippines began in 1994 with a small quantity at less than 0.055 BCM (0.05 Mtoe) per year. The sector is expecting the initial flow of Camago-Malampaya gas in October 2001 and its full commercialisation in January 2002. With the expected growth in demand for natural gas, the government is considering the importation of liquefied natural gas to supplement indigenous gas. It further supports the proposed TAGP network to access the gas resources of its ASEAN neighbours as supply options. It has also planned to continue exploring its potential gas resources.

Cambodia is the latest economy to join its neighbours in the natural gas industry. Discussions have now started between Cambodia and Thailand to jointly develop the Overlapping Claims Area (OCA), which has been estimated to hold up to 280 BCM of gas. In 1997 the Cambodian government granted conditional licenses to five companies to develop four blocks within the OCA, subject to resolution of the overlapping claims between the two economies. Hence Cambodia is not likely to commit to gas imports until it is more certain of its own natural gas resource potential (ACE, 1999). No indications of gas resources are been available for Lao PDR. Rich with hydro-resources, and with relatively low economic activity as compared to its southern neighbour, Thailand, it is quite unlikely for Laos to have any necessity for natural gas in the near future, nor indulge in serious exploratory efforts to seek natural gas resources in its land territory.

CHAPTER 4

NATURAL GAS PIPELINE DEVELOPMENTS

LNG is a mature industry in Southeast Asia with Brunei Darussalam, Indonesia and Malaysia commencing the export of natural gas as early as 1973, 1977 and 1983, respectively. It was several years after the LNG infrastructure was in place that domestic gas pipeline networks began to be laid out to encourage domestic use of natural gas, mainly as fuel for power plants and as feedstock for other industries, especially the fertiliser and petrochemical industries. To date, Brunei Darussalam, Indonesia, Malaysia, Myanmar, Singapore and Viet Nam have a total domestic gas pipeline network of around 9,200 km, including pipelines connecting gas fields and those delivering gas from the fields (mostly offshore) to onshore receiving terminals. Over 2,400 km of pipelines are under construction, and over 4,200 km are being planned within the next few years.

The strengthening of domestic distribution networks will provide a foundation for an integrated cross-border network once they are in place. The TAGP network, which was conceived following a study called the *Masterplan on Natural Gas Development and Utilisation in ASEAN* (see Appendix II), will not be realised as a big joint venture project between the Southeast Asian member economies but rather developed in stages between exporting and importing economies driven by market demand and the availability of nearby gas reserves. Inland domestic pipelines would then become part of a lateral network joining the various cross-border pipelines together.

To appreciate the development of the TAGP network, including domestic pipelines as laterals, it is necessary for this chapter to provide some insight into the development of domestic and cross-border gas infrastructure in the respective economies. The existing pipelines as well as pipelines under construction and being planned are highlighted. In this chapter, only the main natural gas economies in the region - in terms of export, import and pipeline development - are considered.

DOMESTIC PIPELINES

BRUNEI DARUSSALAM

Gas pipeline infrastructure in Brunei Darussalam exists to supply natural gas from the gas fields of Southwest Ampa, Fairley and Champion to the LNG plant in Lumut, and power plants in Lumut, Gadong and Seria. The western part of the economy, where the oil and gas industry is located, enjoys the benefit of having a well-developed gas grid system, owned and operated by the Public Works Department. Total pipeline distance currently in Brunei Darussalam is 920 km (Carson, 1998), inclusive of gas pipelines joining the gas fields and from the gas fields to the liquefaction plant.

INDONESIA

Indonesia is a huge archipelago of over 17,000 islands, and obviously the development of any integrated infrastructure system poses a unique challenge to the economy. Its success in developing a natural gas pipeline network will be dependent on the effective integration of field development activities in Sumatra and Kalimantan, the two major gas producing islands, with markets - especially on the island of Java, the most developed island in Indonesia where almost half of the total population of over 200 million are located (Suharno, 1998).

A total of 4,469 km of natural gas transmission and distribution lines are now operating in Indonesia, and another 1,749 km are under construction. The pipelines are not interconnected – the purpose of these standalone pipelines is to supply gas from a few sources to several specific markets for periods of 15 to 20 years. Currently there are 9 regional systems in Indonesia, as shown in Table 9.

Table 9 Existing transmission and distribution pipelines in Indonesia

Area No.	Location	Pipeline parameters	Description
1	Arun and vicinity		System developed in 1976 with the start of the Arun facilities to produce LNG for export to Japan. These LNG facilities also created infrastructure that currently supply two fertiliser plants and one paper company in the vicinity of Arun.
2	Medan and vicinity	Dist. = 100 km	System designed to deliver gas from PERTAMINA's own fields to markets in the Medan area.
3	Palembang & vicinity		
	Sumatra	Dist. = 536 km Flowrate = 8.4 MMCMD	Transmission pipeline connecting Asamera and Duri. This US$ 590 million project, partially financed by the ADB, is completed and started operation in August 1999.
4 & 5	Java and vicinity		
	i) West Java	Dist. = 360 km	Pipeline installed in 1977/1978 to deliver gas to a steel company, Krakatau Steel, and for the Cilegon power generation. It also serves Pupuk Kujang fertiliser plant and three cement plants along the route.
	ii) West Java	Dist. = 100 km	A subsea pipeline installed in 1994 from ARCO's offshore North West Java to PLN power plants.
	iii) East Java	Dist. = 60 km Trans = 1.12 MMCMD	First pipeline to be built from Kodeco PSC to Gresik to drive 200 MW steam boiler unit.
6	Banyu Island	1.12 MMMCMD	This pipeline delivers gas from the Espan fields to the Bunyu methanol Plant.
7 & 8	East Kalimantan & vicinity		
	i) North area	Trans = 6.72 MMCMD	This system supplies 5.04 MMCMD of natural gas to East Kalimantan fertiliser plant and another 1.68 MMCMD to a methanol plant. Commissioned in 1977 it was developed as part of Bontang LNG infrastructure. In 2000 the pipeline will supply gas to one more fertiliser plant, and two petrochemical plants.
	ii) South area	Trans = 1.12 MMCMD	A limited pipeline built in 1979 to transport gas to a single customer, a PERTAMINA refinery at Balikpapan.
9	Sulawesi & vicinity		Pipeline connecting gas reserves in Energy Equity PSC to markets near Ujung Pandang and markets along the route. Currently it supplies gas to 130 MW IPP at Sengkang. The IPP will require about 5.6 BCM over the project's life. The remaining 11.2 BCM of proven and probable reserves are allocated to support Ujung Pandang development 300 km from Sengkang.

Source: Suharno, 1998

Indonesia is planning to implement five major additional gas pipeline projects with a total length of 3,876 km. These projects are tabulated in Table 10. Figure 9 shows the major existing and planned domestic gas pipelines in Indonesia.

Table 10 Planned transmission and distribution pipelines in Indonesia

Area No.	Location	Pipeline parameters	Description
1	Sumatra	Dist. = 137 km (with looping)	Transmission pipeline connecting Asamera to Sakerman
		Dist. = 330 km	Transmission pipeline linking Sakerman to Batam, (with further extension to Singapore for export)
		Dist. = 23 km	Distribution pipelines in Batam
2	West Java	Dist. = 280 km	Distribution pipeline
		Dist. = 370 km	Transmission pipeline connecting Pegardewa to Cilegon
		Dist. = 150 km	Transmission pipeline connecting Pegardewa to Gresik
3	East Java	Dist. = 292 km	Transmission pipeline, Cirebon – Semarang
		Dist. = 388	Transmission pipeline, Semarang – East Java
4	Sulawesi	Dist. = 270 km	Transmission pipeline connecting Sengkang and Ujung Pandang
5	Kalimantan – Java	Dist.= 1,100 km	Transmission pipeline connecting East Kalimantan to East Java

Source: ACE, 1999

Meanwhile the Ministry of Mines and Energy is restructuring its natural gas sector, with unbundling of services, to make it more competitive. This change should allow more efficient fuel choices for customers and greater transparency and competition for services. Pipelines will be built and sized to support expected future demand growth, and they should in time operate at high load factors. It is intended that in the future no one company will be the sole or preferred pipeline developer. Any company with the requisite financial and technical resources should be able to sponsor pipeline construction and operation.

MALAYSIA

Peninsular Malaysia has a well-developed pipeline transmission system as the economy pursues more domestic utilisation of natural gas to ensure a more balanced energy-mix and environmentally sustainable energy supply. For Peninsular Malaysia, domestic natural gas pipelines are necessary not just to provide fuel for power generation, but also to provide a stable supply of fuel and feedstock for industries. Besides natural gas being relatively clean environmentally, by providing alternative fuel for electricity generation and industrial use, Malaysia could minimise foreign exchange outflow through the displacement of fuel oil. At the same time, increased earnings could be realised through the sales and export of indigenous gas.

Peninsular Gas Utilisation pipelines

The Peninsular Gas Utilisation pipelines, known as PGU, were implemented in three phases. Phase 1 (PGU-I), completed in 1984, connects the gas fields of the Trengganu coast to a 7 MMCMD gas processing plant (GPP) in Kertih, from which gas is sent to an export terminal, one power station, a steel mill and to the Kertih township.

Figure 9 Map of Indonesia showing existing and planned domestic gas pipelines

In Phase 2 (PGU-II) of the project, completed in January 1992, two additional gas GPPs, each of 7 MMCMD processing capacity, were brought into operation, transporting gas through a 730 km pipeline to the west coast and to the south of the peninsula. At the west end of the pipeline the gas is consumed by Malaysia's biggest power plant in Kapar, which has a total generation capacity of 2,326 MW. This plant is triple fired, fuelled by natural gas, oil and coal. The southern end supplies gas to the industrial estate in Pasir Gudang near the southern tip of the peninsula, and the pipeline is also extended to Singapore, exporting 4.2 MMCMD of natural gas. The few kilometres of pipeline extension was the first cross-border natural gas pipeline in Southeast Asia, and in Asia. The PGU-II has a dew point control unit (DPCU) installed to provide a standby capacity of 7 MMCMD.

Phase 3 (PGU-III) of the project extends the pipeline northwards along the coast of Peninsular Malaysia to the southern border of Thailand. Two additional GPPs, each with a capacity of 14 MMCMD and one DCPU unit with a standby processing capacity of 14 MMCMD were constructed near Kertih.

The PGU pipeline project, with a total distance of 1688 km (including loops – the last 227 km of which is still under construction) – is supplying Peninsular Malaysia and Singapore with a total of 56 MMCMD, with an additional standby capacity of 21 MMCMD. It has also spurred the development of a petrochemical industry. A number of petrochemical plants are on-stream such as a Propylene-Polypropylene plant, a Methyl-Tertiary-Butyl-Ethylene (MTBE) plant, and an Ethylene-Polyethylene plant. More petrochemical projects are being planned as Malaysia pursues the goal of becoming a regional petrochemical centre in the next decade. More detailed information on the development of the PGU is illustrated in Table 11. Figure 10 shows the major existing and planned domestic gas pipelines in Malaysia.

Table 11 Gas pipeline infrastructure in Peninsular Malaysia

Project and Phases	Gas Processing and Pipeline Facilities	Complementary Facilities	Dates of Commissioning
PGU-I	32 km HP pipeline to - Sultan Ismail Power Station - Perwaja Steel Mill - Kertik Township 2 of 40 km LPG pipelines to Export terminal	1 unit of 7 MMCMD GPP LPG export facilities - 5 loading arms - 14 m deep harbour	1984
PGU-II	i) 714 km natural gas mainline system from: - Telok Kalong to Segamat - Segamat to Kapar, Port - Klang (west) - Segamat to Pasir Gudang & Singapore (south) ii) 40 km propane pipeline from Telok Kalong to Gebeng iii) 40 km butane pipeline from Telok Kalong to Gebeng	3 units of 7 MMCMD	Pipelines completed in 1991/92 GPPs completed in 1992/93
PGU-III	450 km natural gas pipeline from Port Klang to Malaysia-Thai border	2 units of 500 MSCFD GPPs	1988
PGU-Loop1	265 km looping of the PGU-II pipeline from Kertih to Segamat		Completed in mid-1999
PGU-Loop2	227 km looping of the PGU-II pipeline from Segamat to Meru in the west coast		To be completed in the first quarter of 2001

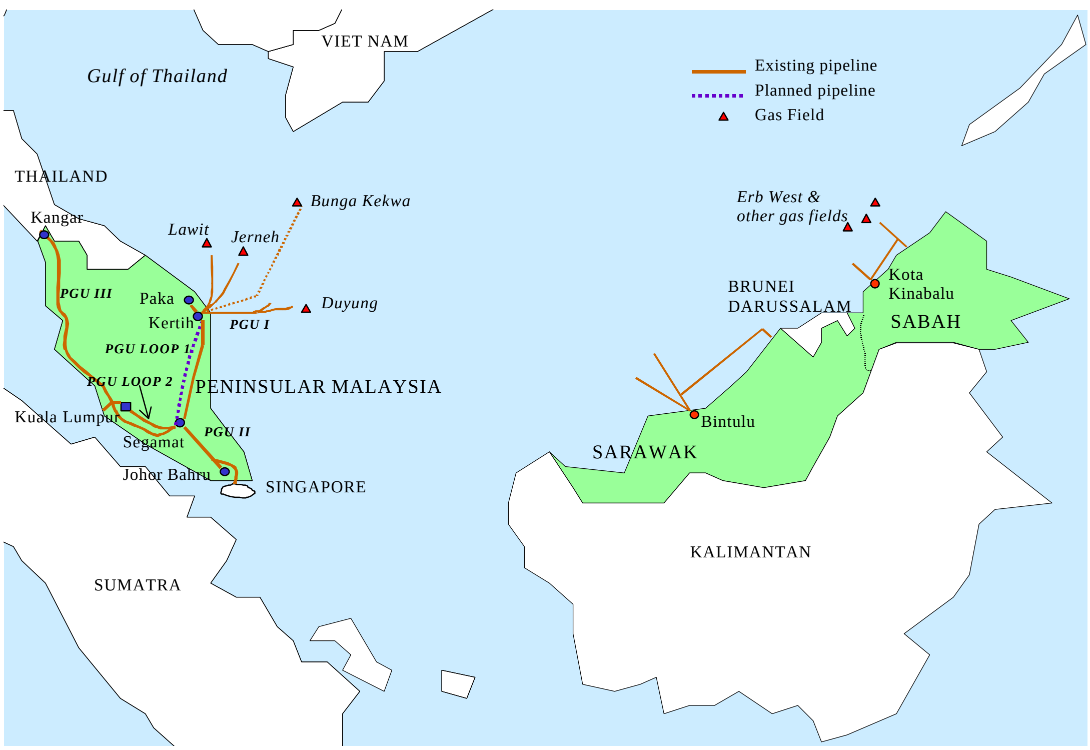
Source: AEEMTRC, 1997

Other sectors also benefit from the existence of the PGU pipelines. One big steel mill not far from Kertih (in the same state of Trengganu) takes an average of 0.84 MMCMD. About a thousand families in Kertih are enjoying direct gas supply from a reticulation system to their homes. Gas Malaysia Sdn Bhd (GMSB), a PETRONAS subsidiary tasked with the transmission and distribution of gas for domestic use, is also planning more widespread use of natural gas for the commercial-residential sector in and around the capital city of Kuala Lumpur and other big cities.

The availability of gas from the PGU pipeline will create a potential market for use of natural gas in the transportation sector also. In support of the national energy and environment policy, and coinciding with the completion of the PGU-II project, PETRONAS has been encouraging the use of gas in the transportation sector since 1991, by implementing a NGV (natural gas vehicle) programme in the Klang Valley, Malaysia's most populated and highly industrialised area. Subsequent to this, a company called PETRONAS NGV Sdn Bhd was incorporated in 1995 to promote and develop the use of natural gas as a more environmentally-friendly transportation fuel. Incentives were also provided to encourage the public and taxi companies to use natural gas, for example by setting the retail price of gas at half the price of oil and by providing import duty exemption.

Another new area of application for natural gas that Malaysia has found successful with the existence of the PGU pipeline network is gas district cooling. This refers to the supply of chilled water for air-conditioning generated by a natural gas-fuelled co-generation plant. Gas district cooling projects are handled by Gas District Cooling (M) Sdn Bhd, another subsidiary company of PETRONAS, which had applied the systems in two big recent projects, the PETRONAS Twin Towers and the new KL International Airport in Sepang. Other new big projects are being constructed with the same air-conditioning system.

Figure 10 Map of Malaysia showing existing and planned domestic gas pipelines



To complete the PGU network GMSB has constructed two pipelines parallel to the existing PGU-I and PGU-III main transmission lines. These loop pipelines, the first of which was completed in mid-1999, would further enhance the gas transmission capacity, security and reliability of gas supply to end users in the Klang Valley, the area with the highest rate of gas utilisation.

Gas pipelines in East Malaysia

In Sabah, PETRONAS has constructed 65 km of gas pipelines to spearhead industrial growth in the state. The pipeline transports gas from the ERB West field to the onshore gas terminal for distribution to domestic, commercial and industrial users in Kota Kinabalu, the capital town of Sabah, as well as to other areas in the west coast of Sabah.

MYANMAR

Onshore natural gas production has been in operation in Myanmar since 1970 and to date the gas pipeline network totals about 1,120 km. In 1996, out of 1.33 BCM produced in Myanmar, 76 percent was used in the power generation sector, with the balance of 24 percent used as feedstock to urea and fertiliser plants.

The Yadana gas field has been developed for a planned production rate of 18.2 MMCMD, of which 14.7 MMCMD will be exported to Thailand and 3.5 MMCMD used domestically. To support domestic consumption, a gas pipeline of 235 km distance, and 20-inch diameter, from the Yadana gas field is under construction to supply gas to a 320 MW power plant and a urea fertiliser plant in Kyaiktaw, about 50 km southwest of Yangon. The total cost for these three projects is estimated to reach US$900 million; with the pipeline estimated to cost US$200 million, the power plant will cost US$200 million, and the urea plant US$500 million.

With onshore gas production anticipated to decrease in the near future, the Yadana–Kyaiktaw pipeline is to be connected to the existing domestic network.

THE PHILIPPINES

The Camago gas field, located in deep water northwest of Palawan, was discovered in 1989 and the adjacent Malampaya oil and gas field was discovered in 1991. The Department of Energy, Philippines believes the combined Camago-Malampaya field has between 70 and 112 BCM of natural gas.

Philippines Camago-Malampaya gas field infrastructure is planned to produce natural gas in the year 2002. The gas is planned to provide fuel for 2,700 MW of power generation to be split between the National Power Company (NPC) (1,200 MW) and the Manila Electric Company (MERALCO) (1,500 MW).

For its 1,500 MW allocation, MERALCO signed power purchase agreements with First Gas Holdings Corporation (FGHC), a joint venture company involving First Philippine Holdings Corporation (40 percent share) and British Gas International (60 percent share) to set up the following two new plants:

i) 1,000 MW gas-fired combined cycle green plant in Santa Rita, Batangas, 7 km from Tabangao, Batangas in Luzon (scheduled completion date 1999) running on condensates from 1999 to 2001, and natural gas from 2002 onwards;

ii) 500 MW gas-fired combined cycle plant (San Lorenzo) in Santa Rita, Batangas.

NPC's 1,200 MW power plant will be built and operated by KEILCO, a subsidiary of Korea Electric Power Company under an Energy Conversion Agreement (ECA). The plant located in Llijan, Batangas, some 15 kilomerters from Tabangao, Batangas is scheduled for commissioning in October 2001.

In terms of local environment strategy, the Department of Energy made a decision to scatter the power plants geographically rather than concentrating them all in one place. Obviously it costs more to provide the respective infrastructure, but it also brings more value-added socio-economic benefits to the local inhabitants.

The joint venture Camago-Malampaya natural gas project between Occidental Philippines Inc (Oxy) and the Philippine unit of Royal Dutch Shell Group, Shell Philippines Exploration BV, is estimated to cost US$ 5 billion. Seven agreements for the implementation of the Philippine natural gas project were signed by the Department of Energy (DOE), the National Power Corporation (NPC), Oxy, Shell Philippines Exploration BV, First Gas Power Corporation, the Subic Bay Metropolitan Authority, and MERALCO. In this 22-year supply contract the government is expected to earn US$ 8.1 billion, and the Province of Palawan is expected to get US$ 2.1 billion in revenue (Chua, 1998).

The gas sales agreements between Oxy and the Philippines Shell consortium with its consumers, First Gas Holdings and NPC vary from a price of US$4.25 to US$4.30 per MMBTU, to be reduced gradually during the contract period. It has been estimated that between 11.2 and 12.6 MMCMD of gas will be delivered under these agreements. An important part of this agreement stipulates that if the supplier (Shell Philippines) is unable to supply sufficient gas due to inadequate gas reserves from the Camago-Malampaya field (please refer to Chapter 2), then the buyer or the power plant owners can purchase an alternative fuel, the cost of which will be borne by Shell Philippines.

A 504-km pipeline is being constructed connecting Camago-Malampaya to Batangas, from where smaller pipelines will be laid to the respective power generating stations. The Department of Energy (DOE) believes that 11.2 to 12.6 MMCMD of gas will be supplied from the Camago-Malampaya field in the gas supply agreements for these power plants. The main 24-inch diameter pipeline, laid in water with the depth ranging from 200 to 650 meters, is expected to be completed in 2001 and start commercial operation in 2002.

Figure 11 shows the Camago-Malampaya – Batangas gas now undergoing construction.

The Philippines Energy Plan 1999–2008 envisions the industries located in the vicinity of the pipeline route as potential markets for gas within the next 10 years. The DOE has made attempts to assess the additional gas demand potential and the corresponding infrastructure requirements. The investigation has so far been focused only on the provinces of Batangas, Laguna, Cavite, and Metro Manila.

First Gas Holding Corporation (FGHC) has applied to Congress for a franchise to construct, own, operate, and maintain a natural gas pipeline for the transportation and distribution of natural gas to different areas in Luzon. Shell also has plans to venture into the gas transmission and distribution segments, looking at the possibility of the Batangas-Calabarzon-Metro Manila pipeline route. The Philippine National Oil Company-Exploration Corporation (PNOC-EC) has likewise done studies on the viability of investing in a transmission and distribution system along the same route.

The Philippines is hoping that in the long-term, when it has exhausted its own supplies or when its resources are no longer adequate to meet its own gas demand, it will bring in natural gas through the TAGP network via the Sabah-Palawan leg of the proposed regional network. The Camago-Malampaya pipeline will be a Philippines asset in linking the economy to the TAGP network.

Figure 11 Map of the Philippines showing existing and planned domestic gas pipelines

THAILAND

Table 12 Planned domestic pipelines in Thailand (1998 – 2010)

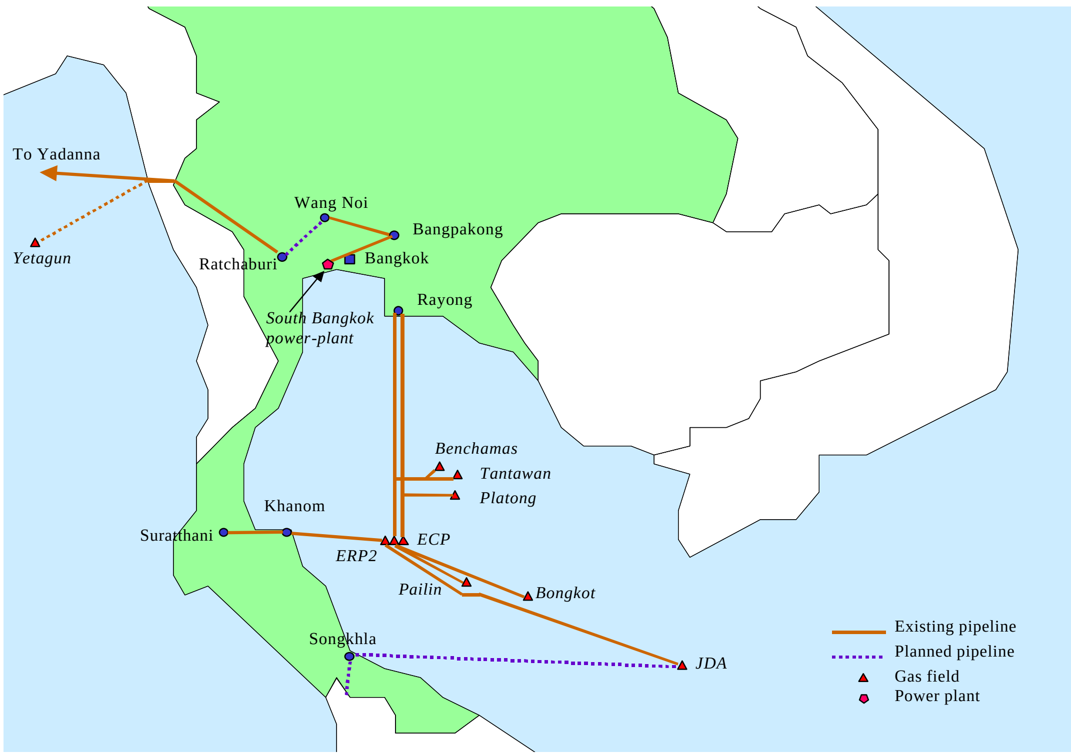
	Project	Year Expected to Commence	Estimated cost in million US$
1.	Pailin pipeline	1999	62
2.	Pipeline from MT-JDA to Erawan	2007	557
3.	Middle compressor, platform, and pipeline connector	2009	896
4.	Pipeline from Rayong to Bangpakong	2009	328
5.	Ratchaburi – Wangnoi pipeline	2001	281
6.	Ratchaburi – Wangnoi pipeline to South Bangkok	2001	280.5
7.	Pipeline from Benchamas to Tantawan	1999	13.5
8.	Pipeline from JDA to Songkhla	2002	159
9	Pipeline from GSP Khanom to Suratthani	2004	95

Source : Petroleum Authority of Thailand

Note : The estimated costs in US$ have been converted with an exchange rate of 36 Bahts per US$1.

Thailand currently has a total of 377 km of natural gas transmission and distribution pipelines (Carson, 1998). With natural gas demand expected to grow to 79.97 MMCMD, in 2005 (29.17 BCM or 26.18 Mtoe for the year), existing transmission infrastructure will not be adequate to transport the natural gas. In November 1996 the cabinet approved the First Pipeline Master Plan (1997–2005), which was later revised and approved again by the Cabinet in October 1997. This Second Pipeline Master Plan (1998–2006) covers 12 projects costing around 78,078 million Baht (US$2,169 million), with the breakdown as shown in Table 12. Figure 12 shows the existing gas pipelines and some of the planned pipelines in Thailand.

Figure 12 Map of Thailand showing existing and planned domestic gas pipelines



VIET NAM

Gas development and utilisation in Viet Nam is concentrated in the southeast where the first gas pipeline system was started in 1993 and completed in 1995, transporting associated gas from the Bach Ho oil field. The project was designed to transport 3.95 MMCMD, to fuel two power plants; Ba Ria and Phu- My 2-1.

With little demand in the North, Viet Nam will focus its resources mainly on developing its southern gas fields, especially the Malai-Thochu Basins (Joint-Development Area with Malaysia), Bach Ho (associated gas field) and the Nam Con Son Basin. Fertiliser plants, power plants and other industrial plants are highly concentrated in the south. A main cross-country trunk line linking the south to the north may not happen in the near future, nor the full development of the comparatively small Song Hong Basin located offshore near the central part of Viet Nam.

Natural gas from the associated gas field in Bach Ho is transported to the nearest power plant in Ba Ria (about 120 km south of Ho Chi Minh City), via an offshore and onshore 16-inch 127 km pipeline, with an existing capacity of 300 MW. This power plant started operation in June 1995. PetroVietnam was responsible for the costs of this pipeline through export credits and other forms of loan. An additional 55 MW power plant will be added at a cost of US$ 55 million, with this extra capacity operating in 1999. In 1997, the Phu-My 2-1 power plant of 288 MW was added, expanding to 300 MW in late 1998. After many years of this associated gas being flared, currently 3 MCM of the gas from the Bach Ho field is being produced and utilised.

The natural gas from the Nam Con Son gas field is to be utilised in an integrated power and urea plant. The 650 – 700 MW power plant will be built on a Build-Operate-Transfer (BOT) basis by BHP (40 percent), BP (32.3 percent), Statoil (16.2 percent) and Tomen/Mitsui (11.5 percent). The urea plant will be built as a joint-venture scheme with Agrium (27 percent) Vinachem (20 percent) Tomen/Mitsui (14.3 percent), BP (14 percent), Statoil (12.2 percent), PetroVietnam (5 percent), Vigecam (5 percent) and BHP (3.5 percent). The power plant and the fertiliser plant will be in operation by the years 2000 and 2001, respectively.

In addition to these two projects, two gas turbine combined cycle power plants are being planned: (1) a 1,100 MW plant costing US$400 million to be funded by the Japanese Overseas Development Agency (ODA (85 percent) and Electricite de Viet Nam–EVN (15 percent); and (2) a 450 MW plant which will be constructed on a BOT basis and later expanded to 600 MW. Another plant (Phu-My 4), of 600–900 MW capacity, will be built on a BOT basis to start operation by 2003.

Two new pipelines are being planned to bring natural gas from the Nam Con Son gas field to the southern coast of Viet Nam (ACE, 1999):

1) A 400-km long pipeline to transport gas from the field to an onshore power plant. This gas is to be used for the development of Phu-My 2-2 700 MW combined-cycle plant at Ba Ria. To date there has been no final agreement on gas price for the project to go ahead; and

2) A 60-km link to the 400-km pipeline, with the gas coming from the Rong Doi gas fields off the coast of southern Viet Nam, planned for use in the expansion of the Phu My Power Complex from 288 MW to 4,000 MW capacity in five years.

In 1997, PetroVietnam, in a joint project with the NKK Corporation of Japan and Samsung of Korea, was awarded a US$60 million contract to build a natural gas separation plant with a processing capacity of 150 million cubic feet/day, to separate propane, butane, and the condensate from the natural gas. The plant, when completed, is expected to produce 330,000 tonnes of LPG to be used domestically and for export. Currently, Viet Nam's growing demand for gas is met by LPG imports from Indonesia, Malaysia and Thailand.

The government has also granted approval to Gas Conservation System Viet Nam Inc to proceed with a US$270 million project for a floating platform producing methanol, using gas flared from the 15-2 oil and gas field. Instead of flaring the gas from the associated gas field, methanol will now be produced for export.

CROSS-BORDER PIPELINES

MALAYSIA – SINGAPORE PIPELINE

The first trans-border gas pipeline in Southeast Asia connects Peninsula Malaysia to Singapore, transporting 1.55 BCMY to the Senoko Power plant in Singapore. Completed in 1992 together with the Second Phase of the Malaysian Peninsular Gas Utilisation (PGU-II) project, a project which aimed to enhance domestic use of natural gas in Peninsular Malaysia, the pipeline starts from the gas receiving plant in Kertih on the Trengganu coast, to Segamat in the State of Johore from where it branches into two legs, with one leg going north-westward to Kuala Lumpur, and other leg going further south to Johore Bahru, from where it crosses the Straits of Johore to the Senoko Power Plant located near the northern part of Singapore. The total length of Phase II is 730 km, with the extension crossing the straits to Singapore only a few kilometres long. This gas transmission from West Malaysia enables the Senoko power plant to diversify its fuel mix for power generation, with 20.5 percent now powered by natural gas.

With the completion of the project, the gas consumption for electricity generation in Singapore increased from 432 Ktoe in 1992 to 1,165 Ktoe in 1996. Although gas exports to Singapore are limited to 4.2 MMCMD, the Senoko power plant currently has been able to use only 3.08 MMCMD to run its two combined-cycle units. Singapore plans to maximise its gas imports by awarding a US$390 million contract to Asea Brown Boveri (ABB) to upgrade the 120 MW power plant to 360 MW (ACE, 1999). This new plant will utilise 1.12 MMCMD of gas (ACE, 1999).

MYANMAR – THAILAND PIPELINE

Southeast Asia's second trans-border pipeline came into existence in late 1998 when the 649 km pipeline connecting the Yadana gas field in Myanmar to the Ratchaburi power plant in the southwest of Bangkok was completed transporting some gas in November 1998.

The pipeline is designed for a total flow rate of 18.2 MMCMD, with 3.5 MMCMD for domestic use and 14.7 MMCMD exported to Thailand. The project which started in 1995 cost US$1.2 billion (on Myanmar's side only), passing through difficult terrain in Myanmar and pristine forest in Thailand. Since November 1998, only 1.82 MMCMD was transported to the Ratchaburi plant due to EGAT's delay in installing all the combined-cycle gas turbine plants in time. After an unavoidable delay, when the Ratchaburi plant is fully completed in 2000, Thailand expects to import 12 MMCMD, with full capacity import subsequently after that. Currently, due to the take or pay contract, PTT is expected to pay the project developers (see but Thailand will not lose the gas – both sides have agreed to a deference of gas delivery. EGAT is not paying any penalty because it has only signed an MOU with PTT for the purchase of the gas from PTT.

A sister pipeline from offshore Myanmar (from the Yetagun gas field), of 390 km is planned to commence operation in early 2000. This will be connected to the Yadana-Ratchaburi pipeline at the Myanmar-Thailand border, with additional exports to Thailand of 5.6 MMCMD. The gas from Yetagun is to power combined-cycle units at Ratchaburi and Wangnoi, situated north-east of Ratchaburi. In 2000, this additional cross-border pipeline will transport 2.88 MMCMD to the Ratchaburi power plants. A 153 km gas pipeline is being constructed to transport part of this gas to the Wangnoi power plant.

It is anticipated that the Ratchaburi and the Wangnoi projects, when fully completed, will be able to utilise all the Myanmar gas imports.

More details about these two cross-border pipeline projects are provided in Table 13.

INDONESIA (WEST NATUNA) TO SINGAPORE

The third cross-border pipeline in Southeast Asia is expected to be ready in the year 2001. In January 1999 a consortium led by Sembawang Engineering and Construction Pte Ltd of Singapore had signed a US$8 billion deal with Indonesia's PERTAMINA and West Natuna Sea gas field operators) Conoco, Premier Oil and Gulf Resources) for the long-term delivery of natural gas from Indonesia to Singapore. Under the agreement, Singapore secured a 22-year supply of natural gas from the West Natuna Sea with a daily volume of 9.1 MMCM. The project cost will be about

US$118 per tonne oil equivalent. The gas will be piped to Singapore via an undersea pipeline from the gas fields to Jurong Island and will be distributed to power and petrochemical companies. The first gas delivery is expected in April 2001.

Table 13 Myanmar–Thailand pipeline details

Gas Field	YADANA		YETAGUN	
Proven Reserve	160 BCM		47.6 BCM	
Gas Production	18.2 MMCMD 14.7 MMCMD for export 3.5 MMCMD for domestic use		5.6 MMCMD All for export	
Contract Duration	30 years		at least 15 years	
Base price	US$3/MMBTU		US$3.07/MMBTU	
Project cost (in Myanmar only)	US$ 1.2 billion		US$ 0.8 billion	
Project Stakes Holders	Blocks M5 & M6		Blocks M12, M13, M14	
	Total (operator)	31.24 %	and the pipeline company	
	UNOCAL	28.26 %	PETRONAS	30.0 %
	PTTEP	25.5 %	Premier Oil (Operator)	26.6 %
	MOGE	15.0 %	MOGE	15.0 %
			Nippon Oil	14.2 %
	Block M8		PTTEP	14.2 %
	UNOCAL	47.5 %		
	MOGE has an option of	15.0 %	Block M10	
			PETRONAS	42.4 %
			Premier Oil (Operator)	22.6 %
			Nippon Oil	20.0 %
			Amerada Hess	15.0 %
			MOGE has an option of	15.0 %
Pipeline distance	Total:	649 km	Total:	170 km
	Myanmar side	409 km	Myanmar side	170 km
	Thailand side	240 km	Thailand side shared with the Yadana pipeline	
Pipeline completion	1998		2000	

Source: IEA, 1999

The gas will be piped to Singapore via a 450-km undersea pipeline from the gas fields to Jurong Island and will be distributed to power and petrochemical companies. The first gas delivery is expected in April 2001. The natural gas will fuel power plants in SembCorp Co-Gen, Tuas Power and possibly PowerSeraya, three IPPs that have recently been established in Singapore.

The pipeline will originate from the West Natuna Sea, and travel through Indonesian territorial waters. At the other end, the pipeline will run through Singapore Straits before landing on the

Southern shore of Pulau Sakra. From an engineering perspective, the active shipping movement in the Singapore Straits crossing will require extensive trenching and other protective measures. The pipeline project is estimated to cost US$465 million, 35 percent of which is allocated to the straits crossing segment, including the receiving facilities, although this segment represents only ten percent of the total length of the pipeline (Suharno, 1998).

INDONESIA (SOUTH SUMATRA) TO SINGAPORE

Singapore Power has started negotiation with Indonesia's PERTAMINA for an additional 5.6 MMCMD from the Asamera gas field in South Sumatra for power generation, industrial and domestic use. As indicated in Figure 9, a transmission pipeline of 536 km has been built connecting the Asamera and Duri gas fields, together with a 137 km loop to Sakerman (the loop is not shown). From Sakerman there will be another 370 km transmission line to Batam, and a 23 km distribution pipeline to Batam. One line will transmit a further 5.6 MMCMD to Singapore, scheduled for delivery in 2002.

THAILAND TO MALAYSIA (MALAYSIA – THAILAND JOINT DEVELOPMENT AREA)

Exploration and appraisal activities were initiated between PETRONAS of Malaysia and the Petroleum Authority of Thailand (PTT) in 1994, with more than US$300 million spent in the Joint Development Area (JDA) on the Malaysia-Thailand continental reef. This resulted in the discovery of 13 gas fields with estimated reserves of 347 BCM.

A Gas Sales Agreement (GSA) was signed on 30 October 1999. The gas purchasers, PETRONAS and PTT will jointly buy the natural gas on an equal share basis from the joint sellers, the Malaysia-Thailand Joint Authority (MTJA) and the contractors for Block A-18, which are PETRONAS Carigali (JDA) Sdn Bhd, Triton Oil Company of Thailand and Triton Oil Company of Thailand (JDA) Ltd.

For the First Phase of the operation, the sellers will deliver gas at an initial rate of 11.05 MMCMD for 20 years beginning from mid-2002. Subject to demand, the Second Phase is expected to commence by 2007, when an additional 8.4 MMCMD will be made available. With this production arrangement, assuming full delivery of gas every day for the 20-year period, total production of the JDA gas will be 131.6 BCM, well within the estimated total JDA reserves of 280 BCM (PETRONAS website).

The infrastructure project includes the construction of an offshore pipeline from the JDA to Songkhla in Thailand. From Songkhla an overland pipeline will be extended to Changlun in Kedah, located at the north of Peninsular Malaysia, where this new pipeline will be connected to Malaysia's PGU-III pipeline. Two Gas Separation Plants (GSPs) will also be built in Songkhla each with a processing capacity of 12.04 MMCMD, taking into account additional demand in the future. Figure 13 shows the planned pipeline route.

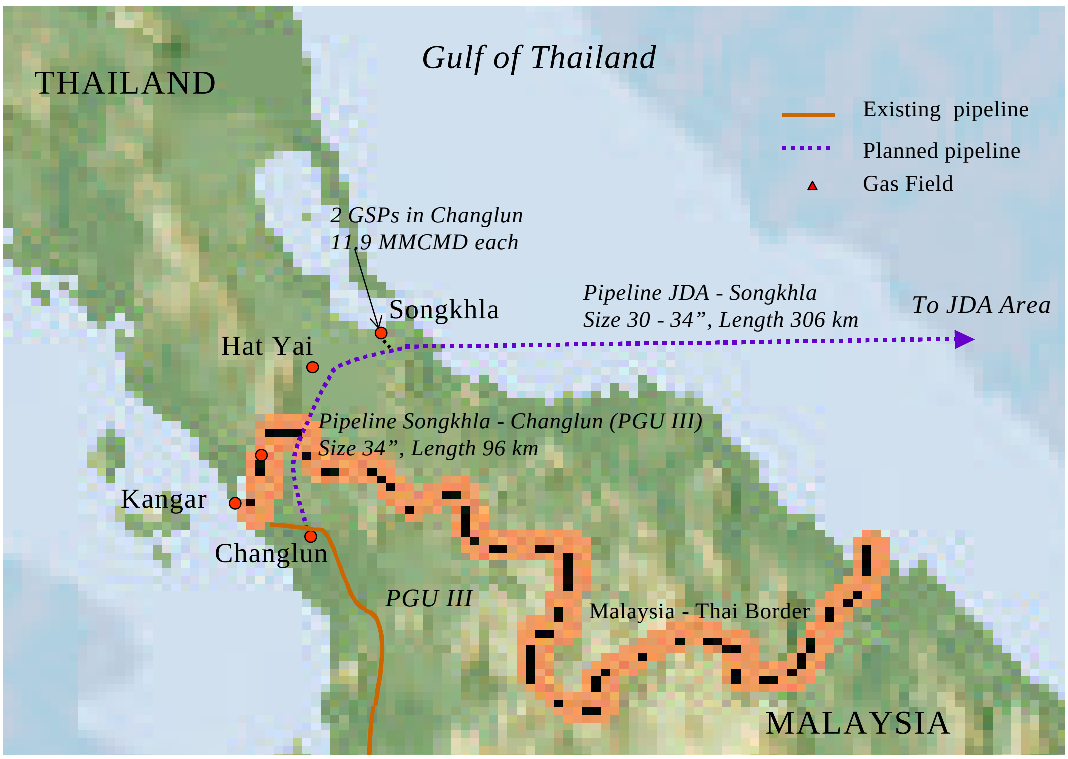
Under the Shareholders Agreement signed in October 1999, PETRONAS and PTT will incorporate two companies, one in Malaysia, called Trans-Thai-Malaysia (Malaysia) Sdn Bhd, and the other in Thailand, called Trans-Thai-Malaysia (Thailand) Ltd. These two new companies will build, own and operate (BOO) on an equal share basis the pipeline and the GSPs. The Trans-Thai-Malaysia (TTM) gas pipeline, as it is called, and the GSPs are expected to cost around US$800 million.

Table 14 shows the Trans Thai-Malaysia cross-border pipeline, called the TTM gas pipeline, which will be constructed in three different sections. In the First Phase gas will come from Block A-18 with a flow rate of 10.9 MMCMD. The additional flow rate of 8.4 MMCMD in the Second Phase will come from Block B-17. (This explains the smaller diameter of the pipeline section from Block A-18 to Block B-17).

Table 14 Sections of the Trans-Thai-Malaysia gas pipeline

Pipeline span	Distance (km)	Size (inches)
i) From Block B-17 to Block A-18	50 km	28" diameter
ii) From Block A-18 to Songkhla in Thailand	277 km	34" diameter
iii) From Songkhla, Thailand overland to Changlun, Kedah, Malaysia.	96 km	36" diameter
Total pipeline distance	423 km	

Figure 13 Map showing the proposed Trans-Thailand-Malaysia pipeline



Together with the Gas Sales Agreement and the Shareholders Agreement, PETRONAS and PTT also signed an umbrella Master Joint Venture Agreement, which outlines possible future cooperation between the two parties for projects in southern Thailand and northern Peninsular Malaysia utilising the JDA gas.

The joint venture project also marks the significance of the political willingness of two neighbouring economies to jointly develop their hydrocarbon resources in their overlapping areas and paves the way for the largest joint venture to date between the two neighbouring economies. The interconnection of the cross-border TTM pipeline with the Malaysian PGU pipeline network a major leap in the development of the proposed TAGP network to expand Southeast Asia's existing and future gas infrastructures to meet the region's increasing energy demand.

The PGU network will serve as a hub for the future TAGP network providing a linkage between Indonesia's intra-regional pipelines in the south and east of Southeast Asia to economies in the north such as Thailand, Myanmar and Viet Nam.

OTHER POSSIBLE PROJECTS

THE EAST NATUNA GAS PROJECT

Indonesia's (and Southeast Asia's) biggest natural gas reserves are currently located in the Natuna D-Alpha field, estimated to have recoverable reserves of 1,260 BCM. Extraction costs for this project are high because of the very high carbon dioxide content (approximately 72 percent).

In 1995, the Natuna infrastructure development was expected to cost US$20 billion to develop and another US$20 billion to operate and maintain during its production years, with the high operation cost centred on the cryogenic separation of carbon dioxide from the extracted gas, and re-injecting the carbon dioxide into the ground at other locations. In 1997, the total project cost was estimated to be US$42 billion, featuring a six-train LNG complex to liquefy 2,400 million cubic feet of methane per day on the shore of Natuna Island, 600 km north-east of Singapore. Offshore, 18 drilling and treating platforms and 910 km of supporting pipelines had been planned.

Initiatives were undertaken between 1995 and 1997 by PERTAMINA, Indonesia's state-owned company, to get prospective buyers for the Natuna D-Alpha gas reserve. A number of agreements and memoranda of understanding have been signed for the development of the Natuna field and pipeline transportation of the gas to neighbouring economies, but the estimated market was insufficient to embark on upstream activities. When the financial crisis came soon after the middle of 1997, and hit Indonesia more severely than other Asian economies, any attempt to bring the Natuna gas to the surface was postponed indefinitely.

The Natuna D-alpha gas field will probably be the main source of gas for the proposed TAGP network. In the study initiated by Southeast Asia (ASEAN-6) in 1995 to 1996, future demand for natural gas in the region could be supplied largely from the East Natuna gas fields, being strategically located at the centre of Southeast Asia.

Figure 14 shows the strategic point of Indonesia's Natuna Island with respect to neighbouring economies.

Table 11 and Table 16 indicates distances of the island from major potential markets, and from the nearest shores of neighbouring economies. The Indonesian government plans to export gas to neighbouring economies sourced from the East Natuna, West Natuna and also from the South Sumatra gas fields.

Figure 14 further indicates the approximate distance of the Natuna fields from markets in Northeast Asia (Korea, Japan and Chinese Taipei). The distances involved suggest that transportation of gas by pipeline might still be viable if the volumes traded (and the pipeline) were sufficiently large - and this implies the possibility of the pipeline supplying gas to several market points along its route. A more detailed analysis of transportation costs, however, will need to be evaluated on a case-by-case basis for each gas field before a concrete conclusion can be arrived with respect to the economics of a long-distance pipeline.

Table 15 Distance of Natuna gas field from demand centres in SE Asia

Economy	Approx. Distance to Market Centre/Capital (km)	Distance to Nearest Shore (km)
Brunei Darussalam	730 (Bandar Seri Begawan)	
Indonesia	1,125 (Jakarta)	270 (nearest shore in Kalimantan)
Malaysia	750 (Kuala Lumpur) 360 (Kuching, East Malaysia) 870 (K. Kinabalu)	550 (Kertih, Peninsular Malaysia)
Philippines	1,740 (Manila)	1,140 (Palawan Island)
Singapore	600	
Thailand	1,350 (Bangkok)	1,230 (nearest shore close to Bangkok)
Viet Nam	1,860 (Hanoi) 780 (Ho Chi Minh City)	780 (Ho Chi Minh City)

Figure 14 Map of Southeast Asia showing the strategic position of the Natuna gas field

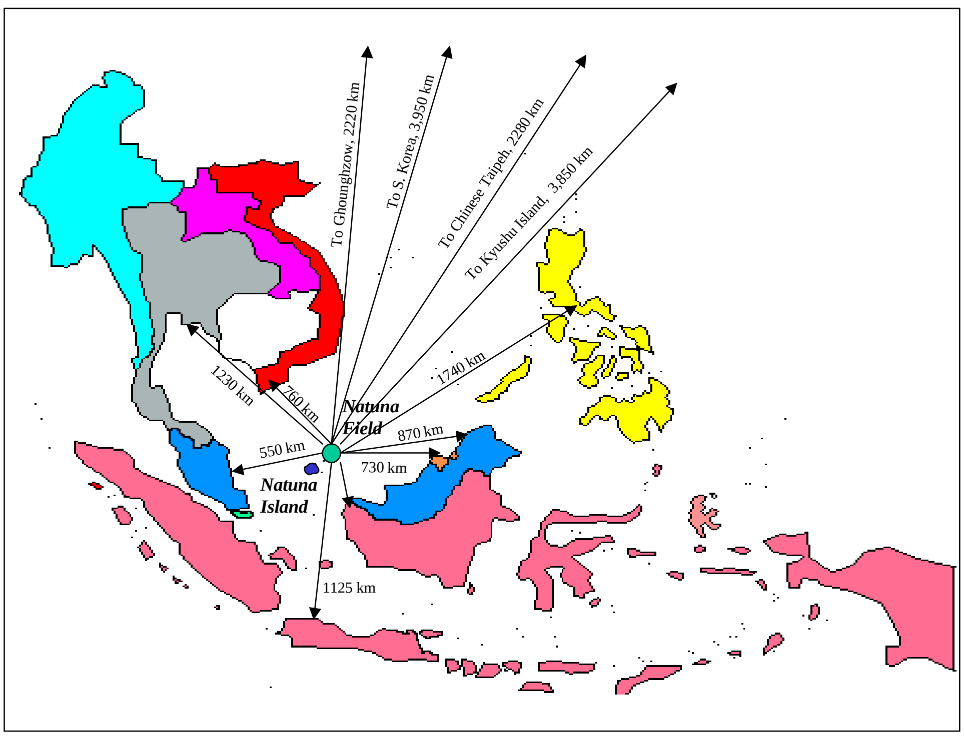


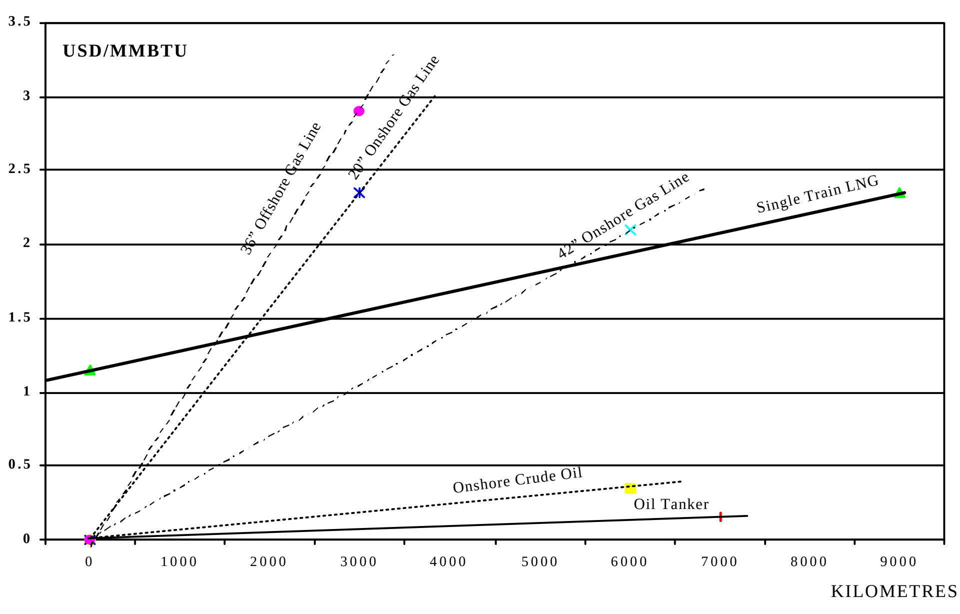
Figure 15 indicates the relative cost of gas transportation in Southeast Asia between LNG and PNG (Jensen, 1998). As observed, gas transportation by offshore pipeline per MMBTU is much more expensive than oil (per MMBTU) either by oil tanker or by onshore crude line. In general, for short distances gas transportation by pipelines is more economical than LNG transportation – as LNG incurs liquefaction costs irrespective of the distance over which it is moved. But over long distances, LNG becomes comparatively less expensive. The figure shows that a 36-inch offshore gas pipeline is competitive with a single-train LNG up to 1400 km. Beyond this distance, the transportation costs become too high to compete.

Hence, the strategic location and relative closeness of the Natuna field to market centres in Southeast Asia makes pipeline transportation a suitable option for the region to embark on more domestic use of natural in the near future.

Table 16 Distance of Natuna gas field from demand centres in NE Asia

Economy	Distance to Nearest Shore (km)
China	2220 (Ghounghzou, South China)
Japan	3850 (southern tip of Kyushu Island)
Korea	3,950 (southern tip)
Chinese Taipei	2,340 (southern tip)

Figure 15 Relative cost of gas transportation



Source: Jensen, 1998

THE TANGGUH GAS PROJECT

For decades now Indonesia has established a reputation as one of the premier LNG supply sources in the world. The main natural gas resources are from North Sumatra and East Kalimantan. Exports are reaching a mature stage and therefore the discovery of the Tangguh reserves near Irian Jaya, with more than 403 BCM of proven reserves to-date, gives Indonesia the additional resources it needs in the near future to maintain its supply position in the Asia-Pacific LNG trade.

Indonesia in 1998 secured a 42.4 percent share of the Asia-Pacific LNG market, with total exports of 36.1 BCM to Japan, Korea and Chinese Taipei. APERC's Demand and Supply Outlook forecasts that these Northeast Asian economies will demand 152.4 BCM of natural gas in 2010. Indonesia will be able to meet only 20 to 23 percent of the region's demand by the year 2010 unless further resources are discovered. With six LNG trains operating in the new supply area of Tangguh, Indonesia's share of the regional LNG market in 2010 could be maintained at around 40 percent. While trying to maintain its position in the LNG market by an extension of current supply contracts and new contracts to meet additional demand each year, PERTAMINA is also eyeing new emerging markets in India and China.

Due to the long distance from Indonesia's own demand centres on the island of Java (more than 2,300 km from Surabaya on East Java, and with very deep sea in the south of Sulawesi), it is quite unlikely that there will be pipeline transmission of the Tangguh gas to Java. The gas industry evolving from the Tangguh reserves might be concentrated to the Irian Jaya territory. It should bring economic development to Irian Jaya, as the LNG plant will provide a major new industrial complex, with petrochemical, fertiliser and other manufacturing industries being attracted by the availability of gas and the liquid by-products of LNG production.

BEYOND THE TRANS-ASEAN GAS PIPELINE NETWORK

As described in Chapter 3, proven gas reserves in Southeast Asia are sufficient to meet the domestic demand of the region for the next 42 to 57 years (depending on which estimates are used). If more resources are proven, then this reserve-to-production ratio would be extended, and export markets could even include China.

Japan is the largest user of natural gas in Northeast Asia and its consumption level is expected to increase 70 percent in APERC's forecast period (from 1995 to 2010). About two-thirds of the natural gas consumed in Japan is for power generation. Korea will also remain a potential market for Southeast Asia's gas. APERC projects that gas demand in Korea will increase 3.3 fold from 1995 to 2010, with the residential and commercial sector expected to consume more than half the gas by 2010. China may join the other Northeast Asian economies in becoming a large market for Southeast Asia's natural gas – with consumption projected to increase 3.7 fold from 1995 to 2010. The industrial sector is the primary user of natural gas in China.

Irkutsk in East Siberia and Sakhalin Island in the Russian Far East are the closest sources of pipeline natural gas supply to Northeast Asia. Estimates of gas reserves have been made for these areas but they have yet to be verified and proven. Many questions remain concerning the adequacy of reserves in these areas to support large 56-inch pipelines, but exploration is continuing and expansion of these reserves seems likely (APERC, 1998). The lack of markets along the long pipeline stretch will also make the purchasing price at Beijing, for example, high unless the size of the demand market in China, and its possible extension to Korea, is sufficiently large to make the price of gas at the consumers end very competitive.

It should be noted that prior to the economic downturn, Korea Gas Corporation (KOGAS) cancelled a total of 18 cargoes totalling 770 million tonnes of LNG from Indonesia and Malaysia.

Further, Korea Electric Power Corporation (KEPCO) had informed KOGAS that it would like to reduce its planned purchase for the period of 1999 to 2003 by 30 percent (IEA, 1999).

One possible link of the TAGP network (which will be revised by the ASEAN Council on Petroleum – ASCOPE to include Viet Nam, Myanmar, and other recent ASEAN members) to Northeast Asia could perhaps be inland to South China to the Yunnan province through Viet Nam since on-shore gas pipelines are less expensive than off-shore pipelines (assuming political and other factors are favourable).

An earlier analysis of gas transportation in Northeast Asia made by a consultant[3] for APERC had indicated that the real market centre for import demand in China was the Changjiang Delta region around Shanghai. In addition to pipeline gas imports from East Russia, China's need could also be supplemented by a supply from Southeast Asia, either by LNG or from the extension of the TAGP network. One possible scenario is gas pipeline deliveries Shanghai could be routed through the Philippines and Chinese Taipei. However, a more rigorous transportation analysis will be needed before it can be ascertained whether gas transportation from Southeast Asia to Shanghai is economically viable by pipeline natural gas (PNG), or whether LNG is more competitive.

As previously mentioned, the main objective of the TAGP network is to provide the infrastructure for a higher utilisation of natural gas in the Southeast Asian region. It does not preclude however, any possible extension of a pipeline from a major gas source to a market beyond Southeast Asia, if the demand is there and if the economics are favourable. The economic cooperation among member economies of Southeast Asia is not a hurdle to an economy having a trade relationship with another economy beyond Southeast Asia. Indonesia, for example, will not hesitate to pursue development of its Natuna East gas fields to export the gas to South China, for example, if the demand is there, and if investors are willing to come in. Eventually it is the economics that will determine whether the gas is to be moved as PNG or LNG.

[3] This analysis was conducted by James T. Jensen of Jensen Associates, Inc for APERC in 1998.

CHAPTER 5

INSTITUTIONAL AND REGULATORY FRAMEWORKS

For a gas pipeline that is planned to stretch across national borders, understanding the policies, and institutional and regulatory frameworks of individual economies is necessary. Such information will provide potential investors with the information they need to assess the risks associated with cross-border projects. This chapter attempts to highlight the way the gas industry is structured in Southeast Asian, the various agencies or institutions and their respective roles, policies with respect to natural gas, and the different pricing and tax structures. The chapter also includes some explanation of the types of contract arrangements between governments, national oil and gas companies, and international contractors involved in the indigenous production of natural gas.

THE GAS INDUSTRY STRUCTURE IN SOUTHEAST ASIA

In Southeast Asian economies, national oil and gas companies (NOGCs) are entrusted with the responsibility of developing gas resources in terms of production, transmission, and distribution. Foreign oil companies are involved in technical operations such as gas exploration and development through contractual arrangements with NOGCs. Different types of contract regime are practised by different economies and they are discussed later in this chapter. For the transmission of gas, pipelines are mostly owned and operated by state owned companies, except in the Philippines, where pipelines are being financed by the operators and will therefore be privately owned and operated.

Concentration of ownership of pipeline infrastructure in state hands can lead to monopolistic and non-competitive market conditions, however most economies are accelerating the process of privatisation of the gas industry and are therefore expecting more competitive markets.

Table 17 and Table 18 provide summarised information on the oil and natural gas institutions in Southeast Asia, and the structure of the gas industry.

BRUNEI DARUSSALAM

Since oil is the main foreign exchange earner, and in line with the economic diversification policy, Brunei Oil and Gas Authority (BOGA) was formed on 1st January 1993 with its main function to submit to His Majesty The Sultan And Yang Di-Pertuan of Brunei Darussalam, advice and recommendations on policies in all matters pertaining to oil, gas, products and their implementation. The other two functions are planning and control of every phase of activities with regards to the development of petroleum and products taking into account the need for conservation of these two natural resources and the environment as well as the award of petroleum mining concessions and contracts and related matters.

The Brunei Shell Petroleum Sdn Bhd (BSP), the national oil company, is engaged in the exploration and production of oil and gas. It currently operates two onshore fields and seven offshore fields. The BLNG, a joint-venture between the Brunei Darussalam government, Shell International and Mitsubishi Corporation, liquefies natural gas purchased from BSP and sells its products, LNG to Japan and Korea. The Brunei Shell Tankers Sdn Bhd (BST) operates LNG carriers to transport LNG. The Brunei Shell Marketing Sdn Bhd (BSM) manages the local marketing of petroleum products and bottles LPG for domestic use. The Jasra-Elf Joint Venture

(JEJV) operates on offshore concessions after discovery of the Maharaja Lela-Jamalul Alam commercial oil and gas fields (ACE, 1999).

Table 17 Oil and gas governmental institutions in Southeast Asia

Economy	Regulatory Agencies
Brunei Darussalam	Brunei Oil and Gas Authority (BOGA) Petroleum Unit Brunei National Energy Committee Department of Electrical Services, Ministry of Development
Indonesia	National Energy Policy Board (BAKOREN) Ministry of Mines and Energy, Energy Resources Technical Committee
Malaysia	Prime Minister's Department Advisory bodies (Cabinet Committee, Petroleum Development Council) National Petroleum Advisory Council) Department of Electricity and Gas Supply (Ministry of Energy, Communications and Multimedia)
Philippines	Department of Energy (DOE), Energy Regulatory Board (ERB) National Economic and Development Authority (NEDA)
Singapore	Ministry of Trade and Industry (MTI), Public Utilities Board (PUB)
Thailand	National Energy Policy Council (NEPC), National Energy Policy Office (NEPO) National Economic and Social Development Board (NESDB) Department of Mineral Resources (DMR), Ministry of Industry Department of Energy Development and Promotion (DEDP) Ministry of Science, Technology, and Environment
Viet Nam	Ministry of Industry (MOI) Ministry of Finance (MOF) State Price Committee (SPC) Prime Minister's Office Ministry of Trade and Tourism (MOTT)

Source: CEERD, 1999; AEEMTRC, 1996

INDONESIA

The responsibility for enacting gas regulations in Indonesia lies with the Ministry of Mines and Energy under the Directorate-General of Oil and Gas. The national energy policies for the development and utilisation of energy resources are, however, coordinated by the National Energy Coordinating Board (BAKOREN).

PERTAMINA is the national oil and gas company, and undertakes gas exploration and development, transmission, and production in collaboration with international operators (mostly with respect to offshore fields). It is the only authorised supplier of gas to power generation and petrochemical plants. The Perum Gas Negara (PGN, later changed to Persero Gas Negara Ltd, with the legal status of limited company, in 1994) has been established to take charge of the distribution and marketing of natural gas. It buys gas from PERTAMINA and sells it to consumers. As part of Indonesia's further restructuring during the current crisis, PGN Ltd plans to restructure into a holding company by creating subsidiaries to handle its principal business activities. The current financial crisis has resulted in these projects being temporarily shelved.

Table 18 Structure of gas industry in Southeast Asia

Economy	Production/ Contract Type	Transmission	Distribution in Domestic Markets)	Consumers
Brunei	Brunei Shell Petroleum Sdn Bhd Brunei Coldgas Sdn Bhd, Jasra-Elf Joint Venture (JEJV)/ Competitive Bidding	Gas Pipeline BSP, Brunei LNG Sdn (BLNG), LNG Pipeline Brunei Shell Tankers (BST)	Brunei Shell Marketing Company Sdn Bhd (BSM)	n.a.
Indonesia	Mobil, Vico, Total, Arco, UNOCAL, Asamera, Caltex, and Exxon sharing contracts with PERTAMINA/ Production Sharing	PERTAMINA	Perum Gas Negara (PGN)	53% - Pusri, Pupuk, Kuyang, Pupuk Kaltim, Pim, Petrokimia Gresik (fertiliser companies), 9% - Perusahaan Umum Listrik Negara (PLN) 14% - Krakatau Stell Company, 14%-refineries, 10% - Independent Power Producer (IPP)
Malaysia	PETRONAS, PETRONAS Carigali Sdn Bhd (PCSB), Esso Production Malaysia (EPMI), Sarawak Shell Berhad (SSB), Sabah Shell Petroleum Company (SSPC), Occidental (Malaysia) Ltd / Production Sharing	*Gas Pipeline* PETRONAS Gas Bhd (PGB) LNG Pipeline PETRONAS	Gas Malaysia Sdn Bhd (GMSB)	Tenaga Nasional Berhad (TNB), IPPs, Petrochemical Plants, Sabah Electricity Board (SEB), Sarawak Electricity Supply Company (SESCO) Iron, Steel and Petrochemical Companies
Philippines	Philippines National Oil company (PNOC) via PNOC exploration, Shell/Occidental Philippines Consortium / Service Contract	First Gas Holdings Corporation (FGHC)	Manila Gas Company	National Power Corporation (NPC or NAPOCOR), IPP
Singapore	PowerGas Ltd (production of town gas)	PowerGas Ltd	Power Gas Ltd	Domestic, commercial and industrial consumers
Thailand	UNOCAL, PTTEP, Total, Thai Shell Exploration and Production Ltd, Esso Exploration and Production Inc / Concession	Petroleum Authority of Thailand (PTT)	PTT	Electricity Generating Authority of Thailand (EGAT), Electricity Generating Company (EGCO), IPPs, Small Power Producer (SPP), Petrochemical industry
Viet Nam	Vietsopetro, PETRONAS Carigali, Total, Sumitomo, PetroVietnam Gas Company / Production, Business Corporation, or Joint Venture	PetroVietnam	Petrolimex	Electricite de Viet Nam (EVN)

Source: CEERD, 1999, AEEMTRC, 1996

The subsidiaries are:

- PT Distribution – to provide the necessary investment and expertise for further development of markets in West Java and elsewhere;
- PT Transcos – to provide private sector investment and technical expertise to operate and develop transmission systems;
- PT Biogas – to produce methane from the 250 tonnes of municipal waste produced daily by the city of Jakarta;
- PT Cogeneration – to provide the technical and engineering resources needed to realise the market potential for gas-fired combined heat and power plants.

Distribution of natural gas to domestic consumers is to be placed under the responsibility of five state-owned municipal distribution companies located within Indonesia's five main consumer cities. Each has a monopoly over the distribution of gas in its region with the exception of large petrochemical plants, which get their gas directly from PERTAMINA. The main gas consumers in the domestic market are fertiliser manufacturers, refineries, IPPs and steel plants.

The above restructuring plan was to have started in early 1998 but the financial crisis has delayed the plan. The main aim of the construction of the transmission and distribution system is to allow 40 percent foreign participation. A new oil and gas law is also being developed to this effect.

MALAYSIA

In Malaysia, the Prime Minister's Department plays a key role in all petroleum matters. Within the department, the Economic Planning Unit (EPU) is in charge of policy formulation, the Implementation and Coordination Unit (ICU) is responsible for petroleum development. PETRONAS carries out exploration, development and production activities. Via its wholly owned subsidiary, PETRONAS-Carigali Sdn Bhd (PCSB), PETRONAS has production sharing contracts with a number of international oil and gas companies as listed in Table 18. Another subsidiary, PETRONAS Gas Bhd (PGB), is responsible for the trans-peninsular pipeline and gas processing. Another company, Gas Malaysia Sdn Bhd (GMSB) distributes the gas to users via the natural gas distribution system.

The Department of Electricity and Gas Supply, under the Ministry of Energy Communications and Multimedia, is the body that regulates the electricity and natural gas supply in the economy.

PHILIPPINES

The Department of Energy (DOE) which is responsible for Philippine energy matters and policies coordinates the activities of key energy institutions in the economy, including the Philippine National Oil Company (PNOC), which undertakes the development of the economy's indigenous geothermal, oil and natural gas resources. The DOE awards service contracts for the exploration and development of indigenous resources. The PNOC-Exploration and Corporation (PNOC-EC) discovered and developed a small gas field in San Antonio, Isabela in Luzon.

Natural gas is a new industry with efforts for the development of the Camago-Malampaya planned to be completed by 2002. The formulation of a comprehensive regulatory framework is underway to achieve an efficient long-term industry structure.

SINGAPORE

The Ministry of Trade and Industry, Singapore has several roles in the energy sector including formulating energy policies, monitoring trends in the energy sector, and supervising the PUB, the Economic Development Board, and the Department of Statistics. PUB is the regulator for the electricity and piped gas industries and the water authority in Singapore.

THAILAND

Thailand's National Energy Policy Office (NEPO) formulates and analyses energy policies and reports to the Prime Minister's Office. The Petroleum Authority of Thailand (PTT), the NOGC for Thailand, procures and produces natural gas through its subsidiary, PTT-Exploration and Production (PTTEP). The other major multinational exploration and production companies are UNOCAL, Total, Shell and Esso. Currently, the gas industry in Thailand is undergoing restructuring. In the near future, PTT transmission and distribution systems will be separated from the gas trading system. PTT Transmission Co. Ltd. will be established as a wholly owned subsidiary of PTT and will be solely responsible for transmission activity. Third Party Access (TPA) to the transmission services will be introduced to promote competition in the gas supply industry.

New main transmission pipelines will be opened to the private sector for investment bidding or for construction and ownership of the infrastructure. The PTT Transmission Co Ltd will be the pipeline network operator, connecting to the PTT mainline network. In addition, the regulatory work will be separated into two phases: the short and the long term. In the short term, NEPO on behalf of the NEPC, PTT and other related agencies will supervise and regulate the natural gas business. In the long term, an Independent Regulator will take over all responsibilities from the authorities previously regulating the business.

VIET NAM

The Ministry of Industry (MOI) sets energy policies and administers the energy master plan. The State Price Committee (SPC) is responsible for evaluating and submitting energy prices to government. The Ministry of Finance (MOF) monitors and inspects the financial activities of ministries as well as enterprises and is responsible for taxation on commodities. PetroVietnam, a solely state-owned oil and gas company, carries out all petroleum operations. Foreign oil companies enter into joint exploration with PetroVietnam through production sharing, business cooperation, or joint venture contracts. PetroVietnam is responsible for oil and gas exploration, production, and transmission. Petrolimex, directly controlled by the Ministry of Trade and Tourism (MOTT), is responsible for the petroleum distribution system. The EVN, a state owned enterprise, is responsible for electricity transmission, distribution and generation under the Prime Minister's Office. Prices for energy, including natural gas, are set by the Prime Minister's Office, after evaluation by the State Pricing Committee.

NATURAL GAS POLICIES

Described in this section are the energy policy objectives of the economies that have undertaken to develop gas infrastructure and to promote domestic gas utilisation. The energy policies of Southeast Asian member economies are focused on reducing dependency on oil, diversifying primary energy resources, and protecting the environment. The development of natural gas resources is favoured for domestic uses.

Economies like Indonesia, Malaysia, Thailand and the Philippines place high priority on encouraging private sector participation and foreign investment in resource development including natural gas.

BRUNEI DARUSSALAM

With power generation in Brunei Darussalam fired almost entirely by natural gas, energy policy measures have been introduced to achieve the following objectives: expanding the use of alternative energy sources, encouraging private sector participation in energy development; considering only the most efficient types of power plants, revising energy prices to increase awareness of true energy costs and discourage energy wastage; and promoting energy efficiency in building design and materials choice. The government is considering coal or fuel oil as alternative fuels to avoid being heavily dependent on gas as a fuel (IEA, 1996).

INDONESIA

Indonesia has adopted five principal policies related to natural gas development, namely: energy diversification; intensification of exploration for energy sources; energy conservation; equitable energy price setting; and environmental protection. Emphasis is placed on diversifying the sources of energy supply (renewable and non-renewable). This policy operates within a framework of economic optimisation and sustainable development. It is focused especially on those energy sources that are not exportable or not available in great quantity. In this respect, natural gas can play a role as an alternative for fuel oil for domestic energy use (NECB, 1998).

Through the development of pipeline networks Indonesia also places high priority on promoting the use of natural gas domestically. It also encourages private sector participation and foreign investment in its resource development.

The government aims to liberalise the gas supply industry and remove the monopoly and quasi-regulatory role of the state oil and gas company, PERTAMINA. The distribution arm of PGN PERTAMINA would become a commercially focused company and its role would be to manage production sharing. Other upstream contract arrangements would be taken over by the Ministry of Mines and Energy. PGN would be separated into transmission and retail companies, and opened to public shareholding, while the producer would sell directly to consumers (Financial Times, 1999).

MALAYSIA

The Malaysian government's energy policy objectives are: to ensure adequate energy supply by reducing dependence on oil; to promote the efficient use of energy and discourage wasteful and non-productive patterns of energy consumption; and to minimise environmental degradation in realising the above goals. In mid-1999, Malaysia has updated its four-fuel policy (oil, gas, coal and hydropower) to include renewable energy as the fifth fuel.

Driven by the government's policy to encourage energy investment overseas, PETRONAS, since its inception in 1974 has now grown to become a large international oil and gas company, even though still wholly owned by the Malaysian government. Today, with over 100 subsidiaries and associated companies, the PETRONAS Group operates in more than 20 countries around the world.

Gas will assist the government achieve the above objectives. According to the Sixth Malaysia Plan (1991-1995) government policy was to expand the use of natural gas as a source of primary energy, to substitute for oil. The PGU network was established during this period. Another objective is to increase the export of LNG to boost foreign exchange earnings. In addition, gas has environmental benefits, greater efficiency and lower economic costs. Malaysia also has a policy of seeking to add value to its resource exports, including natural gas. Consequently, the government does not support additional sales of gas to Singapore or Thailand, but instead the value-added export of petrochemical products using gas as a feedstock (IEA, 1999).

PHILIPPINES

The government views the use of natural gas as an option to further reduce dependence on imported oil. Considering the environmental advantages of this resource, there are also strong incentives for the government to encourage gas market expansion to other end-use markets including industrial, commercial, residential, and transport sectors (ACE, 1999).

SINGAPORE

Singapore is the first pipeline gas importer in Southeast Asia. It has been importing gas from Malaysia since 1992, and looking to expand its natural gas use through new supply from West Natuna, Indonesia. The idea of LNG imports has also been floated to support piped supply either as an on-going or medium term measure (FT Asia Gas Report, 1998).

THAILAND

Key objectives of Thailand's energy policies are to ensure the continued availability of energy supplies; to increase the role of the private sector in energy markets by deregulation, privatisation and the encouragement of competition; to remove barriers to market pricing; to promote energy conservation through greater energy efficiency; and to minimise the environmental problems associated with energy consumption. National policy gives priority to gas as a fuel for power generation, as a substitute for fuel oil, and as a feedstock for petrochemicals, basics industry, and agriculture (IEA, 1999).

VIET NAM

Energy policy objectives, according to the 1996-2000 five-year plan for socio-economic development are as follows: to increase prospects for exploration and exploitation of oil and gas so as to reach an output of some 16 million tonnes of crude oil and 3.7–4.0 BCM of gas by the year 2000; to diversify forms of joint ventures; to raise the capacity of the national oil and gas industry in exploration, exploitation, processing and services; to draw up a master plan for the use of natural and associated gas; to complete the two gas pipeline projects so that 4.5–5.0 BCM per year may be used (see Chapter 4); to build the first oil refinery (6.5 million tonnes/year); to prepare for the construction of the second oil refinery (or the expansion of the first refinery) and of a petrochemical plant (IEA, 1999).

GAS PRICING AND TAXING FRAMEWORK

Pricing is a crucial factor in gas contracts, and is formulated to provide mutual benefits to all involved parties. Natural gas pricing policies in Southeast Asia are greatly influenced by the economic and social objectives of each economy.

Natural gas prices are determined based on the economics of the gas-producing fields. Prices set are normally in accordance with changes in the prices of other fuels, and reflect development and marketing costs to assure an adequate rate of return on investment. The producer price determines the profitability of gas development. It represents the wellhead price of the indigenous gas resource.

Natural gas pricing in Singapore and Thailand clearly reflects market conditions. Malaysia and the Philippines are gradually adopting market pricing, although still take into account social considerations. In Brunei Darussalam, social objectives play an important role in the determination of gas prices. Brunei Darussalam and Indonesia have prepared plans for a gradual shift to market-based pricing, despite the remaining commitment to social equity in their energy policy (Pacudan, 1999).

In Brunei Darussalam and the Philippines, gas producers also participate in downstream activities, such as gas transmission and distribution. Therefore, wellhead prices can be calculated by subtracting consumer prices by transmission cost. In Indonesia, Malaysia and Thailand, where major gas producers are not involved in downstream activities, producer prices are determined by contract arrangement between the sellers and buyers with the involvement of upstream producers and downstream purchasers. An example can be found in Malaysia, where natural gas sold by upstream operators is indexed to the prices of the marine fuel oil ex-Singapore. In Thailand, natural gas prices are determined by an agreement between the gas field operators and PTT. The gas is piped to terminal or consumers such as EGAT and is resold to different consumers at different prices (Pacudan & Lefevre, 1998).

Provided below are the price-setting frameworks for each economy. Table 19 and Table 20 at the end of this section summarise the producers' and consumers' gas price and taxes for five Southeast Asian economies.

BRUNEI DARUSSALAM

Brunei Darussalam has recently formulated action plans to gradually adopt a market based pricing system, but social equity remains a dominant factor in energy pricing policy. With respect to natural gas development and production, in the past a concession-type contract existed, where the government secure rent, first through signature bonuses – during the transfer of rights; and second through royalties, taxes and rentals during the production phase, but now Brunei Darussalam has currently adopted a competitive bidding arrangement for oil and gas exploration. Some petroleum products are already priced according to market levels. Domestic gas prices are highly subsidised and price levels are determined according to what the government believes is equitable to its citizens. Producers are partly involved in gas transmission and distribution and thus, consumer prices (i.e. the price of gas at the city gate) are the most important parameters in determining financial benefits for gas production (as wellhead price can then be calculated by subtracting transmission cost).

INDONESIA

Production gas prices are negotiated on a field-by-field basis and based mainly on the economics of gas field development. In most cases prices are agreed based on the production cost and market prices of substitute fuels. There is a regulated and subsidised gas pricing system now with different prices set according to types of users. Prices for large-scale users such as power plants operated by the IPPs are negotiated directly between the suppliers and the buyers. The gas price to fertiliser manufacturers is heavily subsidised as a result of a policy to provide Indonesia's lower income farmers with inexpensive fertiliser. The gas price to other industries is pegged to residual fuel oil prices. The transmission charges for gas pipeline operators are also negotiated between the pipeline operators and users.

Gas prices in the residential and transportation sectors, which are small in scale, are subsidised. For the residential sector the gas price is set based on the kerosene price, and for the transportation sector a promotional price is set at half the price of gasoline to encourage motorists to use CNG for their vehicles.

MALAYSIA

PETRONAS retains the controlling stake in any production-sharing contract. The gas project sharing contract (PSC) terms are similar to that of oil, except that the division of profits is made based on gas sales rather than production. Under the current terms, gas sales under 58.8 BCM will be shared 50:50 with the contractor, and above 58.8 BCM the profit is split 70:30 with PETRONAS enjoying the 70 percent and its PSC partner 30 percent. New terms are being introduced for higher risk areas with the PSC including revenue-over-cost terms. Gas prices for power generation in Malaysia are pegged to medium fuel oil prices ex-Singapore. For industrial consumption, gas prices are pegged to LPG and diesel prices and negotiated between the supplier and PETRONAS. For the gas produced in Sabah, their prices are determined by a netback analysis. In the residential and the commercial sectors gas prices are competitive with LPG, diesel and fuel oil prices.

THE PHILIPPINES

The Energy Regulatory Board regulates energy prices. Since natural gas production is not yet on line, there is no specific regulatory framework established currently for natural gas.

THAILAND

Producer prices are based on negotiation between PTT and the producers. The price formula is linked to 5 parameters: the wholesale price index; the price of medium-fuel oil (MFO) ex-Singapore; the US index of export prices; the US producer price index for oil field machinery and tools; and the exchange rate of Thailand's Baht vs the US dollar. Consumer price is based on producer prices plus cost of transmission and value-added-tax (VAT) at 7 percent. This price was of the order of US$2.80 per MMBTU in 1993 (IEA, 1996). In mid 1992, the wellhead price for gas from the Gulf of Thailand was reported to be around US$2.15 per MMBTU. The border price for natural gas imported from Myanmar is expected to be higher (EGAT website).

In future, after gas sector deregulation, parties involved in third party access (TPA) will be able to negotiate the price directly with end users; therefore, the gas price is expected to be more competitive. In addition, an independent regulator will be established to ensure a fair transmission cost and to allow even more competitive gas prices to end-users.

Table 19 Producer gas prices and taxes

	Brunei Darussalam (1994)	Indonesia (1995)	Malaysia (1994)	Thailand (1991)	Philippines
Producers' price	-	Case-to-case basis, based on the economics of the gas fields	45% of medium fuel-oil price ex-Singapore	Pricing formula linked to 5 parameters: wholesale price index (25-30%), price of MFO ex-Singapore (15-40%), US index of export prices (20-30%), US producer price index for oil field machinery and tools (20-35%), exchange rate of Baht to US dollar	-
Producers' tax	55% petroleum income tax	48% corporate income tax	40% petroleum income tax	50% income tax plus SRB[c]	None
Royalty	12.5%, 10%, 8%[a]	No royalty on PSC[b]	10% gross production	5-15%	FPIA[d]
Signature bonuses	Negotiable	Several variations	None at present, older contracts have bonuses	$2-$5 million	Negotiable
Production bonuses	-	Several variations	Same as above	None	-
Rentals	B$ 15/km^2 first 4 yrs; $B 45/$km^2$ thereafter	-	-	-	-
Production sharing (profit gas spilt)	-	42.3077/57.6923 in favour of contractor	First 56 BCM 50/50, after 56 BCM 70/30, in favour of contractor	-	Profit oil split 60/40 in favour of government

Notes [a] Onshore, close to shore and remote offshore areas, respectively.

[b] PSC – Production Sharing Contract

[c] SRB – Special Remunatory Benefit is a form of profit tax (rate can vary from zero to 75%)

[d] Filipino Participation Incentive Allowance

Source: Pacudan, 1998

VIET NAM

The pricing framework was developed in 1995. The producer prices are based on negotiation between the state owned utilities, PetroVietnam and EVN. However, this does not reflect the real market costs. PetroVietnam sets the associated gas price for the power sector to be higher than for manufacturing use in urea and methanol production.

Table 20 Consumer gas prices and taxes

	Brunei Darussalam	Indonesia	Malaysia	Thailand	Philippines
Consumers' price	US$/MMBtu	US$/MMBtu	US$/MMBtu	US$/MMBtu	-
Power generation	0.33	2.5-3.0	3.4	2.69	-
Residential	0.17	3.46	6.8	-	-
Commercial	0.30	3.46	6.4	-	-
Industry:	-	-	4.3	-	-
- Fertiliser	-	1.0-1.5	-	2.69	-
- Petrochemical	-	2.0	-	2.69	-
- Steel	-	0.65-2.0	-	-	-
- Cement	-	3.0	-	3.17	-
- Ceramic	-	-	-	4.91	-
- Others	-	-	-	4.22	-
Consumers' taxes	No taxes on gas sales	No tax on gas sales	No tax on gas sales	VAT of 7%	-

Source: Pacudan, 1998

GAS AGREEMENTS IN SOUTHEAST ASIA

CONTRACTS FOR GAS EXPLORATION AND DEVELOPMENT

For gas production, three different types of contract arrangements are made between producers and governments or their NOGCs. They are: concession, production sharing, and service contracts. The types and terms for exploration and production are discussed below at economy level.

BRUNEI DARUSSALAM

Foreign participation in gas exploration and development is permitted by bid. The government owns 50 percent of Brunei Shell Petroleum Sdn Bhd (BSP). Brunei LNG Sdn Bhd (BLNG) is also 50 percent owned by the government, with the balance owned by the Royal Dutch Shell Group of Companies and the Mitsubishi Corporation of Japan, each owning a 25 percent share. BLNG buys the gas produced by BSP and pipes it to the liquefaction plant in Lumut, where the gas is transformed into LNG for export. Table 21 indicates the fiscal regime of natural gas production in Brunei Darussalam.

Table 21 Fiscal regime for gas production in Brunei Darussalam

Corporate Income Tax	30 %
Gas Sales Tax	-
Royalties	8-12.5%
Special Petroleum Tax	25 %

INDONESIA

According to the Oil and Gas Mining Law and the State Oil and Natural Gas Mining Enterprise Law of 1971 or the PERTAMINA Act of 1971, all activities in the petroleum sector are vested in PERTAMINA. This state-owned oil and gas company is entitled to act on behalf of the government in the negotiation and implementation of contracts in the oil and gas sector. PERTAMINA offers various types of contractual agreements: Contract of Work (COW), Production Sharing Contract (PSC), Technical Assistance Contract (TAC), Joint Operation Agreement (JOA), Loan Agreement (LA), and Enhanced Oil Recovery Contract (EOR). Since the mid 1980's the government has no longer offered the COW contract.

Within the present legal framework, there are PERTAMINA's own operations and PSC contracts. Most large-scale oil and gas exploration and development is carried out under the PSC system. Under this contract, PERTAMINA controls the activities of foreign contractors who explore and produce oil in preset zones. After deducting costs, the oil is shared on a basis of 15:85. Table 22shows the highlights of a PSC.

Table 22 Production sharing contracts in Indonesia

Management	PERTAMINA
Operator	Contractor
Investment	Contractor
Production period	30 years
Initial phase	Exploration (Seismic + 1 Exploration Drilling)
Commerciality of discovery	PERTAMINA/Contractor Declaration of Commercial Viability of the Project
Proceeds (Oil)	After cost recovery and tax 85/15 PERTAMINA/Contractor
Corporate taxes	44%
Cost recovery	Full recovery/Depreciation
Investment credit	17%
Gas	Entitled, after cost recovery and tax 70/30 PERTAMINA/Contractor
Domestic market obligation	10% of export price after 5 years
Relinquishment	Gradually, year 3 = 25%; year 6 = 25% and year 10 = 30%

MALAYSIA

Under the Petroleum Development Act of 1974, oil and gas exploration, exploitation, and production in Malaysia is carried out by PETRONAS-Carigali Sdn Bhd (PCSB) or through production sharing contracts between PETRONAS and the operators. The pipelines from the fields to the distribution network fall under the Petroleum Development Act of 1974. The standards and regulatory framework for the gas distribution system, the gas supply equipment and the use of gas in industry from the city gate to the end consumers are governed by the Gas Supply Act of 1993. The Department of Electricity and Gas Supply in the Ministry of Energy, Communications and Multimedia, Malaysia is responsible for the enforcement of the dispositions laid down in the Gas Supply Act.

Table 23 Summary of fiscal regime in Malaysian production sharing contract

Gross Revenue	100%
State Participation	X = 50% up to 56 BCM, 70% above 56 BCM
Contractor's share	100 – X
Royalty	10% of contractor's share
Cost Recovery	Y
Profit oil /gas	(100-X) x 90% -Y
State's share	State participation + royalty+ income tax + CESS (research & development)tax
Company's share	Cost Recovery + Profit oil/gas – Income tax – CESS tax – Company's share of capital and operational expenditures

MYANMAR

No information is available on Myanmar regulatory mechanisms pertaining to oil and natural gas. However, the fact that the Yadana-Ratchaburi pipeline can be operated by a foreign company (Total) is an indication that Myanmar is opening up its natural gas industry to foreign investors and private operators. In fact, in 1988 the government passed the Foreign Investment Law providing guidelines for investment in Myanmar. UNOCAL has become the major player in the development of the Yadana and Yetagun natural gas fields, together with other foreign stakeholders, such as Total, PTT, and PETRONAS.

PHILIPPINES

The Oil Exploration and Development Act of 1972 established the rules under which the government may explore for and produce indigenous petroleum either directly or through service contracts. In a service contract, the contractor finances the exploration and development of the project, provides service technology, receives a share from the net proceeds, and recovers all the operation expenses provided the amount so recovered shall not exceed 70 percent of the gross proceeds. The contractor sells the petroleum produced either in the domestic or export market.

Table 24 Service contract terms in the Philippines

Filipino Participation Incentive Allowance (FPIA)	At least 15% Filipino participation = 7.5% of gross proceeds
Cost Recovery	70% of gross proceeds
Profit Sharing	40% of the net proceeds for contractor
Production bonus	Additional payment if production meets specified level in the contract
Income tax of Contractor	32% of the grossed-up contractor's share

THAILAND

According to the Petroleum Acts of 1971, the government owns all the economy's oil and gas resources and it can award concessions and other rights for exploration and production to qualified bidders that seek to invest in oil and gas exploration. If commercial quantities of natural gas are discovered, the concessionaire will negotiate a long-term or life-of-field contract to sell the gas to the Petroleum Authority of Thailand. Three Petroleum Acts, as shown in Table 25 have been enforced.

Table 25 Petroleum Acts of Thailand

	Act I	Act II	Act III
Phase Period	1971-1989	1982-1989	1990-present
Royalty	12.5% of sales	12.5% of sales	5-15% of sales
Petroleum Tax	50% of net profit from petroleum operation	50% of net profit from petroleum operation	50% of net profit from petroleum operation
Special Remuneration		Annual Bonus	Annual Bonus
Exploration Period	Eight years with a four-year option	Eight years with a four-year option	Six years with a three-year option
Production Period	Within 30 years after exploration completed; includes a 10-year option	Within 30 years after exploration completed; includes a 10-year option	Within 30 years after exploration completed; includes a 10-year option
Concession Acreage	Less than 10,000 km per block, maximum of five blocks	Less than 10,000 km per block, maximum of five blocks	Less than 10,000 km per block, maximum of five blocks

MALAYSIA-THAILAND JOINT DEVELOPMENT AREA

The Malaysia-Thailand Joint Authority (MTJA) was established in 1992 to assume the exploration and exploitation of petroleum resources in the offshore area claimed by both economies and called the Joint Development Area (JDA). Production sharing contracts were signed for three blocks on April 21, 1994, with terms as summarised below in Table 26.

Table 26 Terms of production sharing contract for Malaysia-Thailand JDA

Royalty	10% of production to both Thailand and Malaysia
Cost Recovery Ceiling	50% of production
Profit Split	50 /50 between MTJA and contractors
Research Levy	0.5% of contractors cost recovery and profit
Export Duty	10% of profit oil sold outside Malaysia and Thailand
Petroleum Income Tax	First 8 years of production 10% of taxable income for the next 7 years 20% in subsequent years
Contract Period	35-40 years split 5 years for exploration 5 years for development 5 year for holding 25 years for production

Source : AEEMTRC, 1996

PRIVATE SECTOR PARTICIPATION AND FINANCING

Southeast Asian economies have gone through different levels of privatisation and liberalisation in their energy industries, the most advanced of which are the electricity industries. With the huge upfront investment costs required for the construction of pipeline infrastructures, it is obvious that Southeast Asian economies can no longer afford nor wish to invest government funds for the construction of such projects. Governments would remain as regulators to ensure a level playing field in the natural gas industry so that the interests of all parties involved, including producers, gas transporters, pipeline owners and investors are taken care of.

Investors do not invest in an economy unless they are confident of making reasonable returns on their investments. To achieve this, clearly transparent domestic rules, regulations and institutions in the energy sector as a whole, and the gas industry in particular, largely help in encouraging the private sector to invest and operate in the area. Changing policy stances with respect to privatisation and liberalisation in most Southeast Asian economies is an encouraging sign from the perspective of private sector involvement in the creation of new energy markets, and the strengthening of those in existence.

The Asian Development Bank (ADB) has played a major role in financing energy related projects in Asia. Cumulative ADB lending through 1997 amounted to US$71.6 billion (for 1,448 projects), and 23 percent of this amount was loaned to the energy sector. Of this 15 percent represents natural gas – mostly field development, gas processing, transmission, and distribution. ADB envisions that pipeline construction in Asia over the next decade will amount to about 300,000 km costing roughly US$30 billion, which is an average US$1 million per km of pipeline. Construction of large diameter cross-border pipelines however will cost about US$1.5 million per km (Akhmed, 1998).

Many requirements have to be met to obtain financing for cross-border/international pipelines. First and foremost, markets have to be available and the gas reserves which supply gas to these markets must be adequate to last at least through the loan period, which sometimes stretch over 20-years. Developers will want gas reserves to last much longer than the loan payback period, because pipeline life expectancies are usually quite long. Political stability and international acceptance of the project, as well as high level cooperation and cross-country guarantees are also important to ensure that project risks are minimised during construction and operation.

The financier will also look at other details before giving the green light. The technical viability of the project is certainly important – and technical problems with respect to deep-sea gas production drilling (such as in the Philippines' Camago-Malampaya gas field) and laying of deep offshore pipelines must also be anticipated to avoid high cost variations later. The project must have the ability to mobilise large amounts of investment capital – in other words there is need for innovative financing with a high dependence on capital markets. Most importantly, the contractor must have adequate experience in the construction, operation and maintenance of pipelines. Another important criteria that financiers look for is the probable market price for the gas (usually meaning elimination of subsidies to consumers).

CHAPTER 6

INTERCONNECTION ISSUES AND BARRIERS

This chapter briefly attempts to highlight some issues and barriers with respect to the development of a regional pipeline network, or the integration of cross-border pipelines. As noted in earlier chapters the development of a Southeast Asia regional pipeline network will require step-by-step formation through the integration of domestic and cross-border pipelines as determined by demand and supply availability, in a similar manner to the development of gas pipeline interconnections in North America and Europe.

The natural gas transmission and delivery network in North America developed first within regional markets in individual economies, with each region varying in climate, underground storage capacity, number of pipeline companies and availability of local production. Additionally, the varying demographics of each region dictated different patterns of gas use and potential for growth. Growing US demand for Canadian natural gas has been the dominant factor underlying the interconnections between the two economies (DOE/EIA, 1999). Similarly, in the European Union the 1.1 million kilometres of regional and local lines linking nearly all of the fifteen member states have developed step-by-step over the last thirty years.

As illustrated in the previous chapter, more pipeline interconnections are being developed in Southeast Asia, enabling an increase in natural gas trade between neighbouring economies. The integration is supported by governments, NOGCs and other relevant regional and multilateral agencies, and the TAGP concept endorsed by ministers and leaders has further accelerated such initiatives. Nevertheless, some issues and potential barriers still exist that need to be addressed in enhancing further gas trading through the development of cross-border pipelines in the region.

POLICY BARRIER (AND NATIONAL PRIORITIES)

- During the late 1980s and early 1990s, Southeast Asian economies primarily focused on institutional development and strengthening of their domestic natural gas infrastructures. Although there are only two cross-border pipelines now existing in the region (as discussed in Chapter 4), the prospect of cross-border pipeline links had been very positive, at least until the financial crisis in 1997, after which some planned pipelines had to be postponed or cancelled.

- More than half of Southeast Asia's total gas production is exported as LNG. These large export projects have committed many of the larger and most productive gas reserves to long term export contracts, leaving many smaller fields undeveloped – due to relatively high development costs and lack of domestic markets. However, with gas markets now emerging domestically these smaller fields will be in high demand.

- The financial crisis that started in 1997 adversely effected the energy infrastructure development of three Southeast Asian economies, namely Indonesia, Thailand and Malaysia. Other economies were also affected but with less impact. It has become a matter of highest priority for the most affected economies to revise their development and financial policies with respect to all infrastructure projects, including natural gas development. Consequently, most uncommitted high-cost infrastructure projects have been either postponed or cancelled.

TECHNICAL BARRIER

- There are both actual and potential technical barriers to developing regional trade. The most obvious is a lack of transmission facilities to connect economies. Steps should be taken to bring together the various national plans so as to offer a coherent picture of possible developments.

- To develop a robust market in PNG trading, physical facilities must be in place. Moreover, a network of facilities is needed, rather than point-to-point links for delivering the output of specific producing plants to specific consumers. A network would provide parallel facilities to ensure delivery of gas in the event of scheduled or unscheduled outages. If the network were extensive, this would allow buyers of natural gas to shop between competing producers. At present, no such regional network exists.

- To avoid escalating the costs, domestic pipelines were or are being built to fulfil short and medium term plans, rather than long-term plans. Pipeline diameters are sized and operating parameters designed to fulfil short-and-medium term requirements, and follow national design specifications that vary from one economy to another. The integration of domestic pipelines into a cross-border network at a later stage, while possible, will not be without technical difficulties.

FINANCING

- As emphasized in this report, many opportunities exist for developing natural gas infrastructure for export within the region. Economically viable projects appear to be numerous and private investors are ready to face this challenge. Nevertheless, funding may be hampered by perceptions of risk related to economy specific issues and/or the multinational character of projects oriented towards regional markets. Although the nature and degree of the risks vary from economy to economy, the more common are the financial weakness of buying utilities, foreign exchange convertibility, cautious government policies, and the potential for breach of contract or concession agreements. These can adversely affect the financial viability of projects and, hence, make financial closure more difficult.

- The Asian financial crisis has devalued domestic currencies, expanded interest rates and increased interest servicing on previous borrowings, dramatically reduced purchasing power, and left many energy corporations in the region suffering huge losses. The financial crisis has further aggravated the above situation.

ENVIRONMENTAL IMPACT

- There is a lack of coordinated effort to address the potential social and environmental impacts of fossil fuel development as discussed in Chapter 2 (Jensen, 1998). Considerable strengthening of environmental organisations needs to be undertaken in most of the sub-regional economies both at the ministerial and line agency levels with regard to environmental management.

In addition to the issues raised by the above study, the Masterplan on Natural Gas Development and Utilisation in ASEAN (AEEMTRC, 1996) raised five issues to be resolved as pre-requisites for the development of PNG in the region. The third and fifth points, in particular, are important to the development of cross-border pipeline networks in Southeast Asia

- Pipeline construction - Laying of onshore pipelines is subject to license for rights of way or approval as regards to economy planning, environmental or safety regulations. A proposal to build a pipeline must be submitted to the responsible authorities to get approval or recommendations to modify the construction. Laying of offshore pipelines by foreign companies is required to meet requirements by international law from sovereign state (1958 Convention of the High Seas and Convention on the continental Shelf, United Nations Convention of 1982).

- Gas transit – According to the General Agreement on Tariffs and Trade (GATT), gas is considered as a good and free to transit through the territory of each contracting party. However, the transit must include directives and rules, obligations to member states, and conciliation procedures. The Energy Charter Treaty prescribes that transit should be allowed on a non-discriminatory basis, and transit fees should cover the costs of transportation and effective services.

- Sales and purchase agreements – Long term agreements with a duration of 20 years or more are necessary to build the trans-national grid. The contract structure must consider the following terms; quantities of supply and consumption flexibility, force majeure, take or pay clauses, quality of gas (chemical components, sulphur content, heat value, due point, pressure and temperature), point of delivery, metering, pricing, price revision, billings, payment term, settlement of disputes and etc.

- Arrangements for the construction and operation of long distance pipelines – This should be structured according to the financing requirements and must include the rights of the finance company and guarantees to the lenders.

- Transmission tariffs – This tariff must determine operating cost, a reasonable rate of return, capital base, rate of depreciation. The allocation and tariff cost determination can be recovered through rates and charges referred to as tariffs.

The cost of PNG system is still rather speculative, but some may be feasible under longer-term contract arrangements. Long-term contracts or tariff certainty is necessary to cover fixed investment cost of transmission. However, transmission tariffs have not yet been developed within the region.

Pricing and tariff have become a primary focus of governments in the process of natural gas pipelines development. Pricing of gas is of concern to business sector investors, particularly as heavy subsidisation of domestic gas process in some of member economies can make tariff politically unsustainable. It is important to carry out a series of studies on tariff structure, which in turn will facilitate business sector investment.

To facilitate and enable natural gas pipeline trading among the ASEAN economies, issues and existing policy, technical, financing and environmental impact barrier to cross-border trading would need to overcome.

POLICY MEASURE (REGIONAL COORDINATION)

- A formal regional cooperation agreement for coordination of planning, development, and operation should be established.

- Governments in the region should develop a protocol with recognises the long-term benefits of regional trading and encourage each of the economies to plan and develop PNG jointly. In addition, it should promote opportunity trading for the mutual benefit of the parties.

- A master plan for PNG infrastructure to guide investment decisions should be developed. Development of a plan might be difficult because there is significant uncertainty with regards to many proposed PNG projects. Decision analysis techniques should, therefore, be applied establishing a clear picture of a spectrum of possible transmission system configurations with a ranking of the possible plans according to the most probable ones.

Jensen, in his paper on Natural Gas Policy Issues for the Asian Region [Jensen, 1998], had also elaborately touched on each of the above issues and went further to discuss issues related to the specific characteristics of the natural gas industry in Asia, in particular the Southeast Asian region, concerning the development and integration of cross-border pipelines. His views represent broadly the views of investors and the private sector who would look forward to a very conducive investment environment in the region. The governments, however, while trying to set up the necessary investment climate to encourage more investors in both upstream and downstream parts of the gas industry, also have other interests to take care of. Pricing subsidies or social objectives, for example, that underline the gas policies of some economies cannot just be easily removed without causing some impact on the socio-economic or even political stability.

Southeast Asian economies have high diversities in terms of their resources, economic development, and political and socio-economic structure – situations which indulge each economy seek to resolve only through their own ways. It has been the goal of these economies through the ASEAN cooperation framework to seek more coherence in their national development plans.

CHAPTER 7

CONCLUSIONS AND POLICY IMPLICATIONS

CONCLUSIONS

NATURAL GAS IS AN IMPORTANT ENERGY COMMODITY IN SOUTHEAST ASIA

Natural gas is an important commodity in Southeast Asia. For Southeast Asian economies that have for many years been overly dependent on oil and coal as their main energy source, natural gas use, due to its abundance and inherent qualities as an environmentally-friendly fossil fuel, has significantly increased as these economies pursue energy policies that place high priority on energy diversification, security in supplies, and environmental protection. Even during the economic crisis that hit some Southeast Asian gas exporting and consuming economies hard, the growth rate in gas demand continued to remain high.

Natural gas is also an important export commodity, earning substantial foreign exchange necessary for general economic development.

THE REGION HAS ADEQUATE RESERVES FOR LOCAL CONSUMPTION AND EXPORT

Southeast Asia is endowed with current proven reserves adequate to meet demand for 42 – 57 years, based on current production rates. With the available resources, the region is not only able to make natural gas the obvious alternative for oil diversification programmes, but also maintain export commitments. Proven reserves are likely to increase in the future.

USE OF NATURAL GAS IN THE NON-ELECTRICITY SECTOR

The demand for natural gas will continue to grow in the future, and while the electricity sector will continue to dominate domestic gas utilisation, Southeast Asia is facing the challenge of encouraging more use in the industrial, residential-commercial, and transportation sectors. A more comprehensive domestic pipeline network is a pre-requisite to wider distribution of gas across a range of sectors.

INTRA-TRADING OF NATURAL GAS WITHIN THE REGION IS STILL LOW

Based on 1998 export figures, only 2.3 percent of gas exports originating from Southeast Asia was traded within the region - the rest was exported to Northeast Asia, enhancing the security of energy supply of this region. As LNG exports are not economically practical for short distances, further intra-trading of gas is only possible with the development of a more integrated cross-border pipeline network.

THE TRANS-ASEAN GAS PIPELINE CONCEPT

The TAGP network connecting six ASEAN members (as conceived in mid-1996 after a study conducted by a consortium of European gas companies, supervised by ASCOPE and endorsed by the ASEAN energy ministers), will not be constructed as a mega joint-venture project between member economies but rather realised in stages through the development of discrete cross-border pipelines. The TAGP network is developing – but its exact routing will be determined by market requirements and supply availability, with private sector funding and multi-national oil and gas company involvement.

THE DEVELOPMENT OF A TRANS-ASEAN GAS PIPELINE NETWORK

Currently Malaysia-Singapore and Myanmar-Thailand are interconnected with cross-border pipelines stretching a total of 1,379 kilometres. By the year 2005, five of the six Southeast Asian economies will be interconnected by cross-border pipelines, namely: Malaysia–Singapore, Myanmar–Thailand, Indonesia–Singapore, and Thailand–Malaysia, with a total length of almost 3,000 kilometres. By the year 2020 or earlier, most, if not all, Southeast Asian economies will be interconnected by major trunk lines.

With the existence of cross-border trunk pipelines traversing between supply points and major markets, existing domestic pipelines will provide a branching network and act as a link between major cross-border pipelines. By the year 2005, the total distance of such lateral lines could reach 10,000 kilometres. Hence by the year 2005 the total pipeline length in Southeast Asia will be about 13,000 km, with total trans-border gas transportation capacity of about 260 MMCMD.

THE ROLE OF THE PRIVATE SECTOR AS PRIME MOVER

The private sector, together with the national oil and gas companies (NOGC), will continue to play the key role in pursuing the development of cross-border pipeline projects. One of the APEC Energy Working Group's recommendations in the *Natural Gas Initiative*, states: "Today, however, governments are experiencing growing demands on constrained resources, while numerous projects compete for scarce funds of the development banks. Consequently, the private sector increasingly will provide the capital necessary to develop new natural gas supplies, infrastructure projects and trading networks in the APEC region".

The capital costs of natural gas infrastructure development in Southeast Asia region will be very high. National development regulations should therefore allow private ownership of natural gas facilities and the assignment of security interests in assets.

THE ROLE OF NATIONAL OIL AND GAS COMPANIES (NOGCS)

In all Southeast Asian economies the responsibility of developing natural gas resources has been entrusted to the NOGCs. The operations of these NOGCs vary from one economy to another, from providing concession agreements to being full operating partners, and from being a fund-borrower to being self-funding in their joint-venture projects. A stronger co-operation among NOGCs is encouraged in pursuing projects that have regional benefits as much as national benefits.

THE ROLE OF GOVERNMENTS

Governments have their own important roles to play to encourage the development of natural gas supply and transportation infrastructure across borders. The governments involved would need to establish an autonomous regulator with technical capacity, independent decision-making powers and power to enforce regulations to regulate the natural gas sector and ensure that private and public participants are treated on a fair basis.

POLICY IMPLICATIONS

FULL RECOVERY FROM THE FINANCIAL CRISIS

Southeast Asian economies will need to make a concerted effort to fully recover from the current economic downturn. The economic crisis has greatly weakened the financial strength of some of these economies and has become a major hurdle in continuing many energy infrastructure projects, including gas pipeline projects, some which have been cancelled or postponed.

SECURING SUPPLY CAPACITY

Estimated potential reserves suggest a substantial amount of natural gas availability yet to be proven. However, governments may need to encourage further exploration to enhance supply security. Attractive project-sharing contracts with NOGCs would attract more international players in joint-venture exploration in the region. Against the background of the economic crisis, which has delayed or stalled some natural gas projects, the resources of developed economies and the international financing organisations may need to be called upon to finance natural gas supplies and infrastructure projects.

MARKET DEMAND CREATION FOR PIPELINE PROJECTS

It is important to stimulate the development of natural gas markets and related infrastructure including the development of local infrastructure and domestic trunk pipelines, and the expanded use of natural gas across sectors. While use of natural gas has been very attractive to the power generation sector, the government has to create policies to encourage wider use of natural gas in the industrial, residential-commercial and transportation sectors.

Government level commitment for the export or purchase of natural gas is essential to attracting substantial capital investment for the development of natural gas supplies and infrastructure projects to enhance domestic markets.

POLITICAL SUPPORT FROM GOVERNMENTS

Strong political support from the governments is necessary to expedite the development of the TAGP network. The government could consider, 1) general policies to promote investment and financing of natural gas projects, 2) policies to promote development of natural gas supplies, 3) policies to facilitate the development of markets for natural gas and natural gas-related products and services, 4) policies to facilitate construction of natural gas infrastructure, and 5) policies to facilitate development of domestic and cross-border trading networks for natural gas and natural gas-related products and services.

PROMOTING PRIVATE SECTOR INVOLVEMENT

Private sector participation in the area of natural gas supplies, infrastructure and trading network should be promoted in an environment of transparency and competitiveness. Private investors and project sponsors require assurance that their investments are protected and that the agreements they reach with partners, either private or government-owned, will be honoured and enforced by the government, including provisions establishing mechanisms for dispute resolution, such as international arbitration.

REFERENCES

A. Rahim, A. Bakar. (1998). The Gas Industry in Malaysia, GASEX ‘98, Conference Papers, Seoul, Korea, September 7-10.

ACE. (1999). ASEAN Energy Bulletin. ASEAN Centre for Energy. 3rd Quarter. Vol. 3. No. 3. October.

AEEMTRC. (1998). ASEAN Energy Review. ASEAN-EC Energy Management Training and Research Centre.

AEEMTRC. (1997). ASEAN Energy Journal. ASEAN-EC Energy Management Training and Research Centre.

AEEMTRC. (1996). Masterplan in Natural Gas Development and Utilisation in ASEAN. Vol. 4 – Institutional Issues. ASEAN-EC Energy Management Training and Research Centre. June.

Akhmed, Mukhtar. (1998). Gas Infrastructure Development – Asian Development Bank. Natural Gas in Asia – Facts and Fiction. PECC Energy Forum.

APERC. (1998). Natural Gas Pipeline Development in Northeast Asia. Interim Report. Asia Pacific Energy Research Centre. Tokyo, March.

APERC. (1999). APEC Energy Demand And Supply Outlook. Energy Balance Tables. Asia Pacific Energy Research Centre. Tokyo. February.

ASEAN Secretariat Website: www.aseansec.or.

BP Amoco. (1999). Statistical Review of World Energy. June.

Carson, Margaret (1998). Gas and Power Challenges in Asia-Pacific Rim Markets. Hydrocarbon Asia. Nov/Dec. pp. 38-43.

CEDIGAZ. (1999). Natural Gas in the World. 1999 Survey. Cenetre International d’Information sur le Gaz Naturel et tous Hydrocarbures Gazeux . Paris, October.

CEERD. (1999). Coal and Natural Gas Competition in APEC Economies. Center for Energy-Environment Research & Development. Asian Institute of Technology. Bangkok, August.

CERA. (1997). Natural Gas in Southeast Asia: Scenarios for the Future of Gas Investment. Infrastructure Development, and the Competitive Dynamics of the Energy Marketplace. CERA Workshop. Bangkok, 13 – 14 May.

CERA. (1997). Special Report – The Role of Natural Gas in Thailand’s Energy Future. CERA Workshop. Bangkok, 13 – 14 May.

Chua, Susana E. (1998). The Emergence of Natural Gas as a New Energy Source in the Philippines. GASEX ‘98. Conference Papers. Seoul, Korea, September 7-10.

Damit, Mohamad Awang. (1998). Brunei Darussalam Natural Gas Industry. GASEX ’98 Conference Papers. Seoul, Korea, September 7-10.

DOE/EIA. (1999). International Energy Outlook 1999 – With Projections to 2020. March.

Financial Times. (1999). Asia Gas Report. March.

Financial Times. (2000). International Gas Report. 21 January.

Financial Times. (2000). International Gas Report. 7 January.

GASEX. (1998). Conference Papers. Seoul. Korea. September 7-10.

Guillot. C. (1999) Planning and Implementation of a Gas Network – The European Experience. Forum on Trans-ASEAN Gas Pipeline and Power Grids. Kuala Lumpur, 5 – 7 October.

Hamzah Bakar. (1999). Strategies Towards Regional Cooperation: Gas and Power Interconnections. Proceedings of the ASCOPE Forum On Trans-ASEAN Gas Pipeline and Power Grids. Kuala Lumpur, 5 –7 October.

Hopper, Ronald. (1999). Third Party Access and Tariff Structure. Proceedings of the ASCOPE Forum On Trans-ASEAN Gas Pipeline and Power Grids. Kuala Lumpur, 5 –7 October.

Hydrocarbon Asia. (1999). An Asia Pacific Energy Publication. Vol. 9 No. 6. September.

IEA. (1996). South-East Asia Gas Study. International Energy Agency. Paris.

IEA. (1999). South-East Asia Gas Study. International Energy Agency. Paris.

IEA. (1997). Energy and Climate Change – an IEA Source-Book for Kyoto and Beyond. International Energy Agency. Paris.

Takhyan, Iin Arifin. (1999). Ministry of Mines and Energy. APEC Oil Supply and Demand Security Seminar. 4 - 5 November.

Jensen, T. James. (1998). Natural Gas Policy Issues for the Asian Region. Natural Gas in Asia – Facts and Fiction. PECC Energy Forum.

Khin, J. A. (1999). Natural Gas Markets in Asia. Hydrocarbon Asia. Vol. 9 No. 6. September.

NECB. (1998). National Energy Coordinating Board. Indonesia. General Energy Policy. February.

Nguyen Minh Ngoc. (1998). Natural Gas: Supply and Demand in Viet Nam. GASEX '98. Conference Papers. Seoul, Korea, September 7-10.

Pacudan, R. B. (1998). Natural Gas Pricing Policies in Southeast Asia. Natural Resources Forum. Vol. 22. No. 1. pp. 27-36. 1998. Elshevier Science Ltd.

Pacudan, R. B., Lefevre, T. (1998). An Overview of Natural Gas Pricing Policies in the ASEAN Countries. ASEAN Energy Journal. ASEAN-EC Energy Management Training and Research Centre. Vol. 1. No. 2.

PETRONAS Website: www.petronas.com.my.

Ripple, Ronald D. (1998). The Maturing of Southeast Asia's Natural Gas Sector and the Growing Role of Gas in the Power Sector. Natural Gas in Asia – Facts and Fiction. PECC Energy Forum.

Suharno, Isworo. (1998). The Archipelago Effect on the Indonesian Gas Infrastructure. GASEX '98. Conference Papers. Seoul, Korea, September 7-10.

Sjahrial, Daud. (1998). Tangguh: A New Centre of Indonesian LNG. GASEX '98. Conference Papers. Seoul, Korea, September 7-10.

Symon, A. (1997). Energy In Indonesia. Financial Times Energy Publishing Asia Pacific. Singapore.

Tanimizu, Seiichi. (1999). Demand and Supply of LNG in Asia and Energy Security. Asia Energy Security Roundtable. Tokyo, 27 – 28 May.

Tay, J. Baptist. (1998). Singapore Gas Industry. GASEX '98. Conference Papers. Seoul, Korea, September 7-10.

Tu Cuong. (1998). Gas Industry in Viet Nam – Current Situation and Plan. GASEX '98. Conference Papers. Seoul, Korea, September 7-10.

Van Vactor, Samuel A. (1998). Enhancing Private Investment in the Natural Gas Industry in Asia. Natural Gas in Asia – Facts and Fiction. PECC Energy Forum.

Yamboonruang, Sonchai. (1998). New Gas Market in Thailand. GASEX '98. Conference Papers. Seoul, Korea, September 7-10.

Yamboonruang, Vichit. (1998). Gas Industry in Thailand. GASEX '98. Conference Papers. Seoul, Korea, September 7-10.

APPENDIX I

SOCIO-ECONOMIC AND TECHNICAL INDICATORS
(FOR SELECTED APEC ECONOMIES)

BRUNEI DARUSSALAM

Area	5,765 sq km	Primary Energy Production (97)	
Population (97)	305,000	Crude Oil	160 KBD
GDP (97)	US$4,815 million	Natural Gas	11.3 BCM
GDP per capita (97)	US$15,782	Coal and Lignite	-
Population Electrified	100%	Energy Consumption (97)	
Gross Generation (98)	2,700 Gwh	Oil	0.74 Mtoe
Installed Electricity Capacity (98)	770.2 MW	Natural Gas	0.695 Mtoe ('96)
		Coal and Lignite	-
		Hydroelectricity	-

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998; The Association of the Electricity Supply Industry of East Asia and the Western Pacific, AESIEAP 2000 Goldbook; ASEAN Energy Review, 1998, AEEMTRC; http://www.eia.doe.gov

INDONESIA

Area	1,919,440 sq km	Primary Energy Production (98)	
Population (98)	212.94 million	Crude Oil	1,525 KBD
GDP (98)	US$94.2 billion	Natural Gas	68.4 BCM
GDP per capita (98)	US$442	Coal and Lignite	37.1 Mtoe
Population Electrified	55%	Energy Consumption (98)	
Gross Generation (98)	75,030 GWh	Oil	43.7 Mtoe
Installed Electricity Capacity (98)	21,312 MW	Natural Gas	28.7 Mtoe
		Coal and Lignite	7.6 Mtoe
		Hydroelectricity	0.8 Mtoe

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998; Statistic Indonesia of the Badan Pusat Statistic (BPS), Republic of Indonesia.;
The Association of the Electricity Supply Industry of East Asia and the Western Pacific, AESIEAP 2000 Goldbook; ASEAN Energy Review, 1998, AEEMTRC; BP Amoco Statistical Review of World Energy June 1999.

MALAYSIA

Area	329,733 sq km	Primary Energy Production (98)	
Population (98)	20.93 million	Crude Oil	745 KBD
GDP (97)	US$227 billion	Natural Gas	41.3 Mtoe
GDP per capita (97)	US$11,000	Coal and Lignite	-
Population Electrified:		Energy Consumption (98)	
- Peninsula	99%	Oil	19 Mtoe
- Sabah / Sarawak	75%	Natural Gas	18.4 Mtoe
Gross Generation(98)	60,593GWh	Coal and Lignite	1.5 Mtoe
Installed Electricity Capacity(98)	13,781.6MW	Hydroelectricity	0.4 Mtoe

Source: National Energy Balance, Malaysia 1997, Ministry of Energy, Communication and Multimedia, Malaysia;
The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Goldbook);
Country Paper, the 11th Meeting of ASEAN Power Utilities, 23-26 March 1999, Hanoi, Viet Nam;
ASEAN Energy Review, 1998, AEEMTRC.

PHILIPPINES

Area	300,000 sq km	Primary Energy Production (98)	
Population (98)	75.53 million	Crude Oil	1 KBD
GDP	US$82,51 billion	Natural Gas	0.0092 BCM
GDP per capita	US$1,122.1	Coal and Lignite	1028 Ktoe
Population Electrified	73.4%	Energy Consumption (98)	
Gross Generation (98)	39,827GWh	Oil	18.2 Mtoe
Installed Electricity Capacity (98)	11,427 MW	Natural Gas	0.0052 Mtoe
		Coal and Lignite	2.7 Mtoe
		Hydroelectricity	0.4 Mtoe

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan “APEC Energy Database” 1998;
Country Paper, the 11th Meeting of ASEAN Power Utilities, 23-26 March 1999, Hanoi, Viet Nam;
ASEAN Energy Review, 1998, AEEMTRC.

SINGAPORE

Area	646 sq km	Primary Energy Production (98)	
Population (98)	3.87 million	Crude Oil	-
GDP (97)	US$ 79.5 billion	Natural Gas	-
GDP per capita	US$ 20,452	Coal and Lignite	-
Population Electrified	100%	Energy Consumption (98)	
Gross Generation (98)	28,200 GWh	Oil	29.2 Mtoe
Installed Electricity Capacity (98)	5,521 MW	Natural Gas	1.4 Mtoe
		Coal and Lignite	-
		Hydroelectricity	-

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan “APEC Energy Database” 1998;
The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Goldbook);

ASEAN Energy Review, 1998, AEEMTRC.

THAILAND

Area	514,000 sq km	Primary Energy Production (98)	
Population (98)	61 million	Crude Oil	29.42 KBD
GDP (97)	US$ 176.65 billion	Natural Gas	14.9 BCM
GDP per capita (97)	US$ 2915	Coal and Lignite	6.87 Mtoe
Population Electrified	82%	Energy Consumption (98)	
Gross Generation (98)	93,134 Gwh	Oil	34.5 Mtoe
Installed Electricity Capacity (98)	17,261 MW	Natural Gas	8.47 Mtoe
		Coal and Lignite	7.3 Mtoe
		Hydroelectricity	0.4 Mtoe

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998; The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Goldbook); Country Paper, the 11th Meeting of ASEAN Power Utilities, 23-26 March 1999, Hanoi, Viet Nam; Department of Energy Development and Promotion, Ministry of Science, Technology, and Environment, Thailand.

VIET NAM

Area	329,560 sq km	Primary Energy Production (97)	
Population (98)	77.0 million	Crude Oil	191 KBD
GDP (97)	US$ 24.5 billion	Natural Gas	0.02 BCM
GDP per capita (97)	US$ 318	Coal and Lignite	12.5 Mtoe
Population Electrified	71%	Energy Consumption (97)	
Gross Generation (98)	21,654 GWh	Oil	7.34 Mtoe
Installed Electricity Capacity (99)	5,559 MW	Natural Gas	0.25 Mtoe
		Coal and Lignite	8.6 Mtoe
		Hydroelectricity	N.A.

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998; The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Goldbook); Institute of Energy, Viet Nam, 1999, IE-Viet Nam; http://www.eia.doe.gov

CAMBODIA

Area	181,040 sq km	Primary Energy Production (97)	
Population (98)	11.34 million	Crude Oil	-
GDP (97)	US$ 7.7 Billion	Natural Gas	-
GDP per capita (97)	US$ 715	Coal and Lignite	N.A.
Population Electrified (97)	5 %	Energy Consumption (97)	
Gross Generation (97)	364.56 GWh	Oil	3.37 KBD
Installed Electricity Capacity (97)	94.62 MW	Natural Gas	N.A.
		Coal and Lignite	N.A
		Hydroelectricity	N.A

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998; The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Goldbook); http://www.eia.doe.gov,

LAO PDR

Area	236,800 sq km	Primary Energy Production (97)	
Population (97)	4.8 million	Crude Oil	-
GDP (97)	US$ 1.8 billion	Natural Gas	-
GDP per capita (97)	N.A.	Coal and Lignite	4 Ktoe
Population Electrified	N.A.	Energy Consumption (97)	
Gross Generation (97)	1,260 GWh	Oil	-
Installed Electricity Capacity (97)	256 MW	Natural Gas	-
		Coal and Lignite	4 Ktoe
		Hydroelectricity	N.A.

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998; The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Goldbook); http://www.odci.gov ; http://www.eia.doe.gov,

UNION OF MYANMAR

Area	678,500 sq km	Primary Energy Production (97)	
Population (97)	43.9 million	Crude Oil	9 KBD
GDP (97)	US$ 35.2 billion	Natural Gas	1.3 BCM
GDP per capita (97)	US$ 1,200	Coal and Lignite	85 Ktoe
Population Electrified	N.A.	Energy Consumption (97)	
Gross Generation (98)	4,035 Gwh	Oil	-
Installed Electricity Capacity (97)	1,393 MW	Natural Gas	1.17 Mtoe
		Coal and Lignite	99 Ktoe
		Hydroelectricity	N.A.

Source: The Energy Data Modelling Centre, The Institute of Energy Economics, Japan "APEC Energy Database" 1998; The Association of the Electricity Supply Industry of East Asia and the Western Pacific (AESIEAP 2000 Goldbook); South East Asia Gas Study, 1999, IEA; ASEAN Energy Review, AEEMTRC;
http://www.odci.gov; http://www.eia.doe.gov,

APPENDIX II

THE TRANS-ASEAN GAS PIPELINE NETWORK CONCEPT

Towards the end of the 1980's, a number of efforts were made to promote further development of natural gas utilisation in the ASEAN region, including a proposal for a trans-ASEAN gas pipeline network. In 1989, Italy's Ente Nazionale Idrocarburi (ENI) presented a regional pipeline concept to senior officials from government energy organisations and the national oil companies in the region. The trans-ASEAN gas pipeline network concept was then found to be too ambitious and eventually the concept developed into a more pragmatic study proposal called the Masterplan on Natural Gas Development and Utilisation in the ASEAN Region.

The study was conducted by consultants from John R. Lacey, and gas experts from a consortium of gas companies in the European Union, namely: Snam, Gas de France, and Trans Energy. It was coordinated by the Jakarta-based ASEAN-EC Energy Management Training and Research Centre (AEEMTRC), supervised by representatives of the ASEAN Council Petroleum (ASCOPE), and financed by the European Union. This comprehensive study consisted of seven parts, called tasks, namely:

Task 1: Forecast of Potential Demand for Natural Gas

Task 2: Forecast of Potential Supply of Natural Gas

Task 3: Analysis of Institutional Arrangements

Task 4: Analysis of Existing and Potential Gas Trading Arrangements

Task 5: Technical Analysis

Task 6: Pricing Policies Analysis

Task 7: Analysis of Possible Gas line Linkages

Based on the results and findings of Task 1 to Task 6, the consultants came up with a map of a trans-ASEAN gas pipeline connecting the six ASEAN economies of Brunei Darussalam, Indonesia, Malaysia, Philippines, Singapore and Thailand. Two major assumptions were made in determining the routes of the different legs of the regional pipeline. The first assumption was that the major source of natural gas would be from the Natuna field – despite the very high cost of development due to its high carbon dioxide content. Because of its size, the Natuna field would act as the hub of the system. The second assumption, backed by technical analysis, was that existing domestic pipelines were designed to meet domestic requirements only and as such would not be able to take the high volume flow rates and pressures required for the long-distance transmission of the commodity – hence, new major main trunk pipelines would have to be constructed.

The figure below shows the regional gas inter-connection proposed by the study. The capacity of each leg of the trans-ASEAN gas transmission system was determined by the combination of the demand required for each of the identified regions, availability of resources based on the perceived lifetime of the pipeline and the existing conditions of local transmission systems. The existing transmission systems in place or those being planned have been studied. As the period in which demand will be sufficient to justify a major transmission system go beyond the horizon period of 2020, it was deemed desirable that the existing transmission system would act as a parallel or loop line for the new transmission line. The development of a national integrated pipeline network currently planned or undertaken in Malaysia, Thailand and also Indonesia would be a prelude to the development of the TAGP. The domestic networks in place would also become arterial pipelines linking cross-border pipelines, widening the market further by encouraging more economic activities along the domestic networks.

Following a review of the then existing contractual commitments and remaining reserves in the region, it was concluded that the Natuna field would be critical for the TAGP network to materialise. Natuna gas will flow in both directions - northwards to Thailand either via Peninsular Malaysia or directly to the Bongkot fields - and southwards, connecting the island of Batam with a spur connecting to Singapore, Sumatra and then to Jakarta. The other transmission line would connect the fields at Samarinda with Eastern Java (see Figure A1 below).

Figure A1 Proposed Trans-ASEAN gas pipeline network (1996)

The Java-Bali regional demand is estimated to increase to between 10-12 BCM per year by 2000, 18-27 BCM per year by 2010 and to 33 – 56 BCM per year by the year 2020. The present capacity and the proposed transmission from the Trans-Java pipeline project utilising reserves close to the island will be sufficient to cater for demand until the year 2010.

This would create additional import opportunities before the year 2010. The shortfall would ideally be imported from gas fields near Samarinda. The ideal capacity of the pipeline between Samarinda and the landing point in East Java will be dependent on the demand for gas in East Java and the capacity of the trans-Java pipeline. Assuming that West Java demand cannot be met by domestic gas potential production by the year 2010, a pipeline with a flow rate of 10 BCM per year rising to 15 BCM per year would have to be completed before the year 2006. The capital investment costs of constructing a pipeline from Samarinda to Surabaya have been estimated at around US$1.76 billion. A further investment of US$0.64 billion would be required to construct a pipeline with 8 BCM per year capacity from Surabaya to Jakarta.

Significant volumes of gas would be required to supplement the gas from Samarinda by the year 2020. Unless significant discoveries are made near the Java island, it would seem logical that the supply of gas should be sourced from the Natuna field. Due to the high development costs of the field, economies of scale would be achieved if large demand can be developed simultaneously.

Economic analysis has shown the following option being the most attractive:

By the year 2000, the proposed Asamera (in Sumarta) – Batam pipeline would have been completed. A feeder line from Batam to Singapore should be constructed to meet up with the demand deficit for Singapore. The ideal capacity for this pipeline would be in the order of 6 BCM per year.

By the year 2020, a 28 BCM per year trunk line from Natuna to Batam would be required. Between Batam and Asmera, the 6 BCM per year line will then be reversed operating together with a new 16 BCM per year line delivering 15 BCM per year of gas to Jakarta. Total investment costs for this option is estimated at US$3.9 billion. The transmission cost for this option to Jakarta is estimated at US$0.57 cents/MMBtu discounted at 10 percent before tax for an operating period of 20 years.

The trans-ASEAN gas pipeline network concept has been given high priority by the governments of Southeast Asia. One of the resolutions agreed by the ASEAN Heads of State in the Second ASEAN Informal Meeting of Heads of State/Government in Kuala Lumpur on 15 December 1997 is ASEAN Vision 2020, which among other strategies stipulates: "*establish interconnecting arrangements in the field of energy and utilities for electricity, natural gas and water within ASEAN through the ASEAN Power Grid and a Trans-ASEAN Gas Pipeline and water pipeline, and promote cooperation in energy efficiency and conservation, as well as the development of new and renewable energy sources*".

When the ASEAN Vision 2020 was declared three of Southeast Asia's fastest growing economies, namely: Indonesia, Malaysia and Thailand were deep in an economic downturn and suffered from negative GDP growth in 1997 and 1998. The so-called "Asian Economic Crisis" had affected other Asian economies in varying degree, and in general the economic performance of other Southeast Asian economies have slowed down too. Several big and high-cost infrastructure projects, including energy projects, were either cancelled or postponed during the crisis. In general, energy infrastructure projects that continued were those that were under construction or those that were already being committed. Towards the later half of 1999 signs were showing that the worst of the economic crisis could possibly be over, and it is anticipated that the ASEAN Vision 2020 declaration may soon receive more positive response by the private sector.

In November 1998, a special Task Force was formed by the ASEAN member economies, within the framework of the ASEAN Council On Petroleum (ASCOPE), with members made up of representatives of each of the state-owned oil and gas companies, to make initiatives for the realisation of the ASEAN pipeline interconnection, and to look into the various legal, regulatory and financial issues as elements of importance in a cross-border pipeline interconnection. This group led by PETRONAS of Malaysia had also been requested to revise the pipeline routing based on latest existing and planned development of cross-border pipelines, newly discovered reserves, and new members of Southeast Asian economies that have now become members of ASEAN.

APPENDIX III

RATIONALE FOR THE STUDY

This study is a timely project initiated by APERC. It is conducted with the following background and rationale:

- Natural gas demand for the APEC region is rising rapidly with economic growth and income level. While the primary energy supply for natural gas is anticipated to increase by an annual average growth rate (AAGR) of 3.2 percent between 2000 and 2010 for the whole APEC region, the increase for Southeast Asia is expected to be even higher, at 4.9 percent. Even during the economic crisis, when overall demand growth for energy was negative, natural gas demand recorded a positive 9 percent growth from 1997 to 1998;

- Southeast Asian economies are endowed with abundant hydrocarbon deposits. Proven natural gas reserves have continued to increase over the years, in spite of the fact that production rates have also increased. In comparison with the ongoing discovery of new gas reserves, oil and coal reserves have remained static;

- Domestic pipeline networks in some Southeast Asian economies are increasing rapidly to provide the infrastructure for wider domestic utilisation of natural gas. More cross-border pipelines are either under construction or being planned. The so-called Trans-ASEAN gas pipeline network are actually in the process of development. Environment and technology factors are likely to facilitate further natural gas pipeline development in Southeast Asian economies.

This study is also initiated in support of various policy decisions made at APEC ministerial and Energy Working Group meetings. Specifically, these policy decisions are:

- APEC Ministers Declaration of Okinawa Meeting held in 1998 (Paragraphs 17 and 18)

> *Driven by the goals of promoting economic development and growth, increasing energy security and improving the environment, demand for natural gas in APEC is expected to grow significantly over the next 20 years. Meeting this demand will require increased natural gas production and significant new infrastructure development;*
>
> *Natural gas trading networks comprised of internal and cross-border pipelines, LNG terminals and distribution systems would promote economic development within economies and further cooperation and trade between the APEC economies. Feasibility studies on pipeline projects in this region should be conducted.*

- APEC Non-Binding Energy Policy Principles (Articles 1 and 2)

> *Emphasize the need to ensure energy issues are addressed in a manner which gives full consideration to harmonisation of economic development, security and environmental factors,*
>
> *Pursue policies for enhancing the efficient production, distribution and consumption of energy.*

This project is also in support of the related EWG Activity: APEC Natural Gas Initiative: Accelerating Investment in Natural Gas Supplies, Infrastructure and Trading Networks in the APEC Region.

At the ASEAN level, at the 14th ASEAN Summit, on ASEAN Vision 2020, in December 1997, Kuala Lumpur, the ASEAN Heads of Governments specifically expressed the need for the ten Southeast Asian economies to be interconnected in their energy infrastructure, as follows:

> *… establish interconnecting arrangements in the field of energy and utilities for electricity, natural gas and water within ASEAN through the ASEAN Power Grid and a Trans-ASEAN Gas pipeline, and promote co-operation in energy efficiency and conservation, as well as the development of new and renewable sources of energy.*

STUDY OBJECTIVES

With concerns for energy supply security and the environment now high in Southeast Asia, member economies are pursuing natural gas as one alternative to diversify their fuel sources. Coal is another fuel getting wider application in the coal producing member economies as part of their fuel diversification policies - reducing over-dependence on oil. However, the environmental impacts of large-scale coal utilisation has made it less attractive than natural gas; unless mitigation measures are incorporated in coal power plants, which incur higher up-front costs in construction. Natural gas is an attractive alternative, but while the region is endowed with sufficient gas reserves, bringing the gas to market by long-distance pipelines is a challenging task, with a multitude of issues to be addressed domestically as well as regionally (this is discussed in further detail in the next chapter).

The general objective of this report is therefore to provide policy makers with information that can be used to support decision making, to further encourage the development of cross-border pipeline infrastructure in the region.

The specific objectives of the study are as follows:

- To assess the latest gas reserves and provide Southeast Asian member economies the latest scenarios on natural gas infrastructure development in the region;

- To highlight the institutional and regulatory issues in connection with the natural gas industry in Southeast Asia; and

- To explore the development of the TAGP network, being formed in stages with the construction of cross-border pipelines, with the full network established by the linking of these main trunk lines by lateral pipelines.

Trading of natural gas amongst Southeast Asia economies exists currently but is still in its infancy, at 2.4 percent of total exports outside the region. It is also the overall objective of this study to provide information to further promote trading of natural gas amongst Southeast Asian member economies, especially by pipelines as their existence will speed up economic development in general, and more specifically enhance development and economic activities along the pipeline routes.

This study by no means intends to revise or update the comprehensively completed Masterplan on Natural Gas Development and Utilisation in ASEAN (please see Appendix II), endorsed by the ASEAN energy ministers in 1997. This study rather, would complement further the Masterplan

Study by assessing the latest scenarios in natural gas supply, consumption and future outlook that seems necessary now for three reasons. Firstly, ASEAN is now comprised of ten economies in Southeast Asia – when the Masterplan Study was undertaken only six economies of ASEAN (ASEAN-6) were incorporated. Secondly, the financial and economic crisis that is entering now into its third year has turned around drastically the development picture of the member economies, at least in the short-term. Thirdly, while a complete regional interconnection proposed in the earlier study is far from being realised, we are now witnessing a number of cross-border interconnections taking place.

SCOPE

This study investigates the current natural-gas scenario in each of the Southeast Asian economies, by looking first at the region's potential supply. The latest reserves are assessed including analysis of the latest plans for the bulk transportation of natural gas within the region for domestic consumption.

The study includes a review of the projections for natural gas development in Southeast Asia – in particular the potential for trading of gas amongst Southeast Asian economies. With four of the economies having export capabilities (Indonesia, Malaysia, Brunei Darussalam and Myanmar), and two economies in demand of natural gas (Singapore and Thailand), it is rational to assume that member economies will place high priority in the intra-trading of natural gas within the region, in the spirit of cooperation that bonds ASEAN politically and economically.

Chapter 1 of the report provides a brief background of Southeast Asian economies and the natural gas scenario in this region.

Chapter 2 highlights the benefits of using natural gas and of having gas pipelines interconnections. The environmentally benign characteristics of natural gas are particularly noted in this chapter.

Chapter 3 looks at the market potential by analysing natural gas reserves and production, consumption trends, and supply and demand projections until the year 2010. It provides information on the supply potential of the gas reserves in Indonesia, Malaysia, Brunei Darussalam, and Myanmar (natural gas exporting economies), as well as Thailand, Viet Nam and the Philippines (which produce gas for their own domestic consumption). This chapter also reviews current trends in natural gas consumption in Southeast Asia. APEC Energy Balance data is widely used in this analysis, supplemented with data obtained directly from the member economies and from other reliable sources. Southeast Asia's outlook for natural gas demand until the year 2010 relies on the APEC Energy Demand and Supply Outlook, updated by APERC in September 1998.

Chapter 4 focuses on existing and planned domestic pipeline projects. Domestic pipelines can be considered to serve a double role. Currently, domestic pipelines serve to transport natural gas from gas fields to markets, with the power sector being the major consumer. In the near future, the development of cross-border pipelines will connect these domestic pipelines together, upgrading them into lateral or arterial pipelines.

Chapter 4 also examines cross-border pipelines as a natural development in the formation of the TAGP network. The much discussed regional pipeline will not be realised as a joint inter-governmental project involving most if not all economies, but rather initiated bilaterally between economies by the private sector driven by supply and demand, with the exact route determined by the shortest link from gas fields to markets.

Chapter 5 provides an overview of the institutional and regulatory structure related to the natural gas industry. An understanding of the institutional and regulatory mechanisms that are transparent in nature would attract investors and international gas contractors to be involved in the development of natural gas supplies and transmission projects in the region. Natural gas pricing and taxing practices in Southeast Asia are included in this chapter.

Chapter 6 discusses some of the pipeline interconnection issues and barriers, and finally Chapter 7 provides the conclusions of the study as well as policy implications related to the development and acceleration of natural gas infrastructure in the region.

The impact of the Asian financial crisis on energy demand and supply growth, and in causing various impediments and delays to the infrastructure development plan in the region is touched at the relevant topics of discussion in this report.

Although Myanmar is not a member economy of APEC, it is not excluded from this study. This is because Myanmar, since 1999, had become a natural gas exporter in the region, and in the year 2000 will become the biggest pipeline natural gas supplier in the region, exporting gas to an APEC economy. Hence any discussion on natural gas development in Southeast Asia would not be complete without including Myanmar.