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INDUSTRIAL SECTOR NATURAL GAS USE

A STUDY OF NATURAL GAS USE IN INDUSTRIAL SECTOR IN APEC ECONOMIES

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FOREWORD

I am pleased to present the final report of the study, Industrial Sector Natural Gas Use in the APEC Region. The study is one of five new research projects commenced in mid-2001, and is the third in a series of natural gas studies conducted by APERC since 1999.

The objective of the study is to investigate the penetration of natural gas in the industrial sector for selected economies, with the aim of providing some insights for other economies that have plans to promote the use of natural gas in the industrial sector after successfully utilising the fuel in the power sector. This study also provides a complementary analysis to the natural gas projection conducted in the APEC Energy Demand and Supply Outlook 2002.

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

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

Tatsuo Masuda
President
Asia Pacific Energy Research Centre

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LIST OF ABBREVIATIONS

APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ATR	Autothermal reforming (in GTL process)
ASEAN	Association of Southeast Asian Nations
BAU	business-as-usual
BCM	billion cubic metres
CCGT	combined cycle gas turbine
CH_4	methane
CIS	Commonwealth of Independent States
CHP	combined heat and power
CNG	compressed natural gas
CNPC	China National Petroleum Corporation
CO_2	carbon dioxide
DME	dimethyl ether
DRI	direct reduced iron (in steel making)
EAF	electric arc furnace
EDMC	Energy Data and Modelling Center (Japan)
EIA	Energy Information Administration (USA)
EWG	Energy Working Group (APEC)
FGD	flue-gas de-sulphurisation
GDP	gross domestic product
GHG	greenhouse gases
GPA	gas purchase agreements
GTL	gas to liquids
GW	gigawatt (10^9 watts)
GWh	gigawatt hour (one million kilowatt hours)
HBI	hot briquetted iron (in steel making)
HRSG	heat-recovery steam generator
HSFO	high sulphur fuel oil
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
IPPs	independent power producers
kcal	kilo calories
ktoe	kilo tonnes of oil equivalent
kTY	kilo tonnes per year
kW	kilowatt (= 1,000 watts)
kWh	kilowatt hour (= 1,000 watt hours)
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LRMC	long run marginal cost
MCF	thousand cubic feet
MCFD	thousand cubic feet per day
MCMD	thousand cubic metres per day
MCM	thousand cubic metres
MMBTU	million British thermal units
MMCM	million cubic metres
MMCMD	million cubic metres per day
Mt	million tonnes
MtC	million tonnes of carbon
Mtoe	million tonnes of oil equivalent

MTBE	methyl tertiary butyl ether
MW	megawatts (= 1,000 kilowatts)
MWh	megawatts hour (= 1,000 kilowatt hours)
NO_X	nitrogen oxides
NUG	non-utility generation
PNG	Papua New Guinea
POX	partial oxidation (in GTL process)
SINOPEC	China Petrochemical Corporation
SO_X	sulphur oxides
SRMC	short run marginal cost
TCF	trillion cubic feet
TCM	trillion cubic metres
TPEC	total primary energy consumption (supply)
TWh	terawatt hour
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
US	United States (of America)
US DOE	United States Department of Energy

EXECUTIVE SUMMARY

BACKGROUND

The objective of the study is to investigate the penetration of natural gas in the industrial sector for selected economies, with the aim of providing some insights for other economies that have plans to promote the use of natural gas in the industrial sector, after successfully utilising the fuel in the power sector. This study also provides a supplementary analysis to the natural gas projection conducted in the APEC Energy Demand and Supply Outlook 2002.

NATURAL GAS USE HIGHLIGHTS

In Northeast Asia and Southeast Asia, most of the natural gas available in the market is utilised in the power generation sector. The prospects for increased consumption in other sectors, especially the industrial sector and residential/commercial sector, remain modest due to lack of infrastructure and lack of high-volume consumption.

Gas producing economies, on the other hand, are placing greater emphasis on wider utilisation of natural gas to contribute to fuel diversification and reduce the environmental impact of energy consumption. The use of natural gas is more diversified in the more developed APEC economies. Natural gas is predominantly used in the industrial sector, with the power and residential sectors taking lesser shares. This diversified use is driven by a more balanced fuel share, as outlined by the economies' energy policy, and the availability of domestic reserves.

The liberalised natural gas industry in developed economies has also enabled the private sector to invest in a comprehensive and intricate network of gas pipelines and numerous storage facilities located at gas centres.

The United States and Canada are an example of where natural gas utilisation is more diversified. The United States has the longest history of using natural gas among APEC economies. Natural gas, which is produced domestically, is mostly consumed in the industrial sector. The supply and availability of natural gas in the two economies are also reinforced in a way because the two economies are interconnected by cross-border pipelines with import and export activities going on simultaneously on different pipelines in different regions, and with a net flow occurring from Canada to the United States. There is also a net flow of natural gas from Mexico to the United States.

With the exception of Indonesia, gas producing economies such as Brunei Darussalam, Malaysia and Thailand have made natural gas the dominant fuel for power generation. Malaysia, however, is keen to utilise more natural gas for the industrial sector, requiring the existing trunk pipeline to be further developed with distribution pipelines to prospective industries. Malaysia is also keen to make itself the hub of a gas-based petrochemical industry in Southeast Asia.

Some good examples are to be found in China and Chile. In China, natural gas is primarily consumed by the industrial sector and as feedstock in fertiliser plants. In 1999, 6,351 ktoe (24.4 percent) was consumed as fuel for the industrial sector and an additional 4,466 ktoe (17.1 percent) as feedstock in fertiliser plants. The power sector consumed only 2,280 ktoe (8.7 percent). The residential/commercial sector consumed 4,849 ktoe (18.6 percent). In Chile, industrial use of natural gas in 1999 was 345 ktoe or 7.1 percent while its residential/commercial sector and electricity sector accounted for 4.7 and 23.6 percent, respectively.

With the advent of natural gas as a major energy source and the emphasis placed on it in many international meetings, it is likely to continue increasing its significance as it is propelled into the spotlight as the fuel for the new millennium. This is due to its many advantages, including its attractiveness as a clean fuel.

REPORT CONTENT

Chapter 1 introduces the objectives and scope of the study. Two distinct features are worth mentioning:

- In developed economies, there is widespread use of natural gas in the various sectors and adequate infrastructure is in place; and
- In developing economies, natural gas is used more as fuel for electricity generation and chemical and petrochemical industries, and there is a lack of infrastructure to use it. This is mainly because of lack of capital and individual national policies and interests.

Chapter 2 discusses consumption levels in more depth at the regional level, such as in North America, Southeast Asia, Northeast Asia, Latin America and Oceania within APEC. Chapter 3 discusses issues pertaining to the North American experience, while Chapter 4 explores natural gas use in the industrial sectors of selected economies.

Chapter 5 presents independent projections of natural gas use in industries for selected economies and looks at how they compare with those in the APEC Energy Demand and Supply Outlook 2002. The primary importance of this work is that the methodology used in this project is the same as that used for the APEC Energy Demand and Supply Outlook 2002. Chapter 6 discusses conclusions and recommendations.

The Appendix describes the GTL or gas to liquids process. This may be seen by oil-producing economies as a system in competition with oil.

CONCLUSIONS AND POLICY IMPLICATIONS

Most developed APEC economies have their own indigenous natural gas resources and have been able to utilise natural gas widely across sectors, namely the power sector, the industrial sector and the residential and commercial sector. Because of the wide availability of natural gas in Canada and the United States, North America has become a region in APEC where natural gas is more versatile in its use. Australia has a similar situation to North America.

However, in the developing and gas-producing economies (especially Malaysia, Indonesia and Thailand) the greatest use of natural gas is for the power sector. The amount used in the residential/commercial and transport sectors is small to the point of being almost insignificant. The gas used in the industrial sector is mainly concentrated in the chemical and petrochemical industries, including fertiliser manufacture, although some gas is being used in industries such as iron and steel (for Indonesia and Malaysia), and cement (for Indonesia).

Lack of an infrastructure network is one of the main reasons why, in developing economies where indigenous gas is available, natural gas is not being widely utilised in the industrial sector. Governments could encourage further utilisation of natural gas in the industrial sector through policies and strategies that would make it more accessible in the market.

CHAPTER 1

INTRODUCTION

OVERVIEW

In Northeast and Southeast Asia, a major part of gas consumption is as fuel for power generation. Natural gas is used for power generation because it is cleaner than coal and oil. Because the price of gas per energy unit in importing economies tends to be higher than that of other hydrocarbon fuels, prospects for increased consumption in other sectors remain modest.

Gas-producing economies, on the other hand, are placing greater emphasis on wider utilisation of natural gas to contribute to fuel diversification and reduce the environmental impact of energy consumption. However, various constraints have to be overcome before natural gas plans can be fully realised.

An analysis of natural gas consumption in more developed economies (such as the US, Canada and Western Europe), where gas pipeline infrastructure is well-developed, shows that the industrial sector represents a larger share of total consumption than for developing economies.

The main reason natural gas is not used extensively in sectors other than for electricity generation in Northeast and Southeast Asia is the lack of pipeline infrastructure. Except for a few specific energy-intensive industries, demand tends to be insufficient to justify the cost of building a network. Hence, in economies where the supply infrastructure is not well-developed, gas customers are usually located close to the main trunk gas line.

In this study, Northeast Asia covers China, Japan, Korea and Russia. Southeast Asia predominantly covers the APEC members of the Association of South East Asian Nations (ASEAN) which comprises Brunei Darussalam, Indonesia, Malaysia, Philippines, Singapore, Thailand and Viet Nam. North America includes Canada, Mexico and the US, Latin America is Chile and Peru and Oceania is Australia, New Zealand and Papua New Guinea.

OBJECTIVE OF THE STUDY

Natural gas is currently the fastest-growing primary energy source. Technological changes and market developments in power generation and industrial gas utilisation are helping to drive this demand for natural gas. Fuel diversification policies and environmental concerns are also prime drivers, as long as gas competes on favourable terms with other fuels such as fuel oil and coal.

The objective of the study is to investigate the penetration of natural gas in the industrial sector for selected economies with the aim of providing some insights for other economies that have plans to promote the use of natural gas in the industrial sector, after successfully utilising the fuel in the power sector.

This study also provides a supplementary analysis to the natural gas projection conducted in the APEC Energy Demand and Supply Outlook 2002.

It provides a comparison between natural gas consumption patterns in developed economies and consumption patterns in developing APEC economies. The key difference is in the extent of penetration of gas in various sectors of the economy.

Demand for gas pipeline infrastructure is also different. Natural gas consumption for industry requires a more intricate network of smaller pipelines, and sufficient storage facilities. The role of the gas regulatory body also needs to expand to cater for such requirements.

SCOPE OF THE STUDY

Industrial use of natural gas covered in this study is that for thermal/heating (such as for furnaces in iron and steel companies and for boilers), for cogeneration or non-utility generation (NUG), or for combined heat and power (CHP) generation for company use. It also covers the use of natural gas as a feedstock to both the petrochemical and fertiliser industries. As for cogeneration, although it is understood primarily to be a technology for power generation, in this context cogeneration is regarded as an industrial application, with the power generation confined to immediate use of the industry and the heat generation consumed directly in the industrial process.

The study does not include the use of gas for air-conditioning for large industrial or commercial complexes, which has recently become popular, nor does it include the use of natural gas for industrial transport.

In economies where gas is predominantly used in the electricity generation sector, there is some analysis of the penetration of natural gas in other sectors. For these economies, their natural gas consumption policies are also discussed in order to examine the potential for future expansion of natural gas. Due to time constraints and inadequate data, not all APEC economies are included. Pricing, which is the most important enabling factor in the use of gas as an alternative energy source, is also discussed.

An analysis of natural gas demand projections in industries is attempted at the end of the study. The projections are supplementary to the APEC Energy Supply and Demand Outlook 2002, which formed a major APERC undertaking during the same period that this study was conducted. Using bulk natural gas projection figures for the industrial sector produced by the Outlook 2002, and based on analysis contained in the early part of the study, the later part of the study looks at specific gas-consuming industries of interest to certain economies and projects their gas consumption patterns for the coming two decades.

The study also includes descriptions and analysis of the use of gas for processes and technologies in some of the applications mentioned above. So as not to impede discussion of consumption patterns, the part on processes and technologies is made an annex to the main report.

CHAPTER 2

NATURAL GAS CONSUMPTION IN APEC ECONOMIES

OVERVIEW

Considering forecasts of strong growth in demand and increasing dependence on oil from outside the region, APEC economies have placed high importance on natural gas as an energy source, so as to promote energy diversification and to maintain energy security. Driven by the goals of promoting development and growth, increasing energy security and improving the environment, demand for natural gas in APEC is expected to grow significantly over the next two decades.

The APEC Energy Demand and Supply Outlook 2002 forecasts that natural gas demand of the industrial sector in the APEC region would increase from 236.3 Mtoe in 1999 to 389.7 Mtoe in 2020. This represents an annual average growth of 2.4 percent across the region. In 1999, 38.1 percent (432 Mtoe) of gas demand was for fuel for power generation, while 20.8 percent (236.3 M toe) was for use in industry, both for energy and non-energy purposes. The residential and commercial (ResCom) sector had a share of 24.7 percent (280.2 Mtoe) and petroleum refineries and other consumers accounted for 14.7 percent (166.9 Mtoe).

APERC projects that in 2020, power generation will account for 50.3 percent (980.2 Mtoe) of gas consumption, while 20.0 percent (389.7 Mtoe) will be used by industry. The ResCom sector is forecast to account for 19.4 percent (377.3 Mtoe) and petroleum refineries and others for 10.1 percent (196.6 Mtoe).

One rationale of why the APEC region places high emphasis on increasing natural gas use is the higher availability of natural gas reserves in the APEC economies as compared with oil reserves. Globally, total oil reserves currently amount to 140,400 million tonnes (or more than one trillion barrels). Only 14 percent of the oil reserves are located in APEC member economies. The rest (about 120,000 million tonnes) are located in non-APEC economies, more than three-quarters of which are in the Middle East. Within the APEC region, four economies with the biggest reserves (more than 1,000 Mt) are Russia (six percent, or 6,700 Mt), Mexico (three percent or 4,100 Mt), the US (two percent or 3,500 Mt), and China (two percent or 3,300 Mt, slightly less than the US). Among these four big oil producers, only Russia and Mexico are net oil exporters. Other APEC economies have small reserves of less than 1,000 Mt, with Indonesia, Malaysia and Brunei Darussalam currently being net exporters.

For natural gas, however, 43 percent of the world's supply is found in the APEC region. Supplies outside of APEC amount to about 83,000 BCM, of which 60 percent is in the Middle East. Russia has the biggest reserves (33 percent of the world's reserves at 48,140 BCM), and much of these are untapped and looking for potential buyers, with markets expected especially in the Northeast Asian region - China, Korea and Japan. The US comes next at about three percent or 4,650 BCM. Despite having bigger gas reserves than Canada, the US is a net gas importer from Canada, as we shall see later. Indonesia, Malaysia and Brunei Darussalam in Southeast Asia are among the world's biggest exporters of natural gas. Australia and Mexico are also gas exporters. Other economies such as Thailand and Viet Nam consume what they produce. Papua New Guinea may become an exporter of natural gas to northeast Australia, but due to uncertainty over timing, that project has not being included in the APEC Energy Demand and Supply Outlook 2002.

The use of natural gas is more diversified in the more developed APEC economies, with a more balanced fuel share as outlined by the economies' energy policy, and the availability of domestic reserves. The relatively high fuel percentage of oil and coal use in these economies makes the use of natural gas even more desirable, because of its more environmentally benign benefits. Driven by demand and supply, the liberalised natural gas industry has also enabled the private sector to invest in a comprehensive and intricate network of gas pipelines and numerous storage facilities located at gas centres.

In developing economies, on the other hand, most of the natural gas is utilised for power generation, with other sectors taking much smaller share. The lower capital cost per kWh of installation capacity, the relatively shorter period of plant construction, higher plant efficiency, and the environmental benefits of natural gas have made natural gas-fuelled power generation much desired, especially in the developing economies where the fuel percentage use of coal is high. Advanced technologies in combined cycle gas turbines have made natural gas the fuel of choice for power generation, both for new power plants and for renovating old open-cycle gas turbine plants when their life-cycle is still long. The high volume of natural gas required daily for power plants make investment in supply trunk pipelines highly viable economically. Although these economies, especially natural gas producers, may want to enhance the utilisation of natural gas in other industries, the "chicken-or-egg" problem explains why wider natural gas penetration is hindered. Individually, industries' fuel needs may not be high enough and prospective pipeline owners may not want to invest in pipelines if the demand rate is not economically sufficient. On the other hand, industrial operators will not show any interest in switching to natural gas unless the pipeline infrastructure is already available. They may also lack confidence in it as a secured supply in the future.

The following section briefly looks at natural gas availability and consumption in some APEC economies.

NATURAL GAS CONSUMPTION IN NORTH AMERICA

In the United States and Canada, natural gas utilisation is more diversified. Natural gas, which is produced domestically, is mostly consumed in the industrial sector. The supply and availability of natural gas in the two economies are also reinforced in a way because the two economies are interconnected by cross-border pipelines, with import and export activities going on simultaneously via different pipelines in different regions, and with a net flow occurring from Canada to the United States. There is also a net flow of natural gas from Mexico to the United States. Table 1 gives a summary of sectoral gas consumption, in ktoe, in Canada, Mexico and the United States.

Table 1 Sectoral gas consumption in North America in 1999, ktoe

	Electricity	Industry Sector	Residential and Commercial	Transport Sector	Non-energy (Fertilisers and Petrochemical Feedstocks)	Other	Total Consumption
CDA	5,110 (7.3%)	22,580 (32.1%)	18,165 (25.8%)	5,319 (7.6%)	4,415 (6.3%)	14,636 (20.8%)	70,303 (100%)
MEX	9,283 (30.0%)	10,180 (32.9%)	796 (2.6%)	8 (0.0%)	1,064 (3.4%)	9,622 (31.1%)	30,952 (100%)
USA	141,411 (27.1%)	120,091 (23.0%)	181,003 (34.7%)	17,250 (3.3%)	0 (0.0%)	62,233 (11.9%)	521,987 (100%)

Note: 'Other' includes agriculture and other transformation and statistical discrepancies

Source: IEA (OECD) Energy Balance Tables (2001)

The economy descriptions below provide a short overview of the natural gas industry in North America. More description and analysis on the natural gas industry, in particular the use of gas in the industrial sector, for North America is provided in Chapter 3.

CANADA

Canada is a major gas producer, and proven reserves stood at 1,629 BCM in 1999. With a relatively small population of 30.49 million, Canada looks to the US (population 278.23 million) as a major market for its gas production (144,702 ktoe in 1999, 54 percent of which was exported to the US). Canada is the world's third-largest gas producer after the United States and Russia, and the second-largest gas exporter after Russia. In the 1990s, domestic supply grew at an average rate of 2.9 percent per year.

The Maritimes and Northeast pipeline from the new Sable Island gas field to New England, which went into operation at the end of 1999, has become Canada's main export line to the United States. The completion of new trunk pipelines in 2000, such as the Alliance from Alberta to Chicago, and Vector from Chicago to Southern Ontario, has enhanced and facilitated further exports to the US. Additional capacity to serve and develop domestic markets in Nova Scotia and New Brunswick was expected to go into service in 2001.

Gas interconnections between Canada and the United States have progressed considerably in recent years. The Northern Border Pipeline, an extension of the Nova Pipeline, came on-stream in late 1999 and connects Chicago through the upper Midwest. The Maritimes and Northeast Pipeline came on-stream in January 2000, running from Sable Island to New England. North America's longest pipeline, the Alliance Pipeline, which cost US$2.5 billion to build, is 3,000 km long and is designed to deliver 36.4 million cubic metres per day of gas from western Canada (Fort St. John, British Columbia) to the Chicago area. The pipeline went into commercial service on 1 December 2000. The US utility company Pacific Gas & Electric imports gas from British Columbia. The Millennium Pipeline connects Canadian sources to southern New York and Pennsylvania.

In 1999, 22,580 ktoe (32.1 percent) of natural gas supplies in Canada were consumed in the industrial sector, 4,415 ktoe (6.3 percent) was used as fertiliser and petrochemical feedstock, 18,165 ktoe (25.8 percent) in the residential/commercial sector, and 5,319 ktoe (7.6 percent) in the transport sector. The power sector consumed only 5,110 ktoe (7.3 percent), a very small percentage compared with power sector consumption in other APEC economies. Almost 60 percent of Canada's power generation in 1999 came from hydropower. The sector for 'Other', predominantly oil and gas extraction and petroleum refining, accounted for 14,636 ktoe (20.8 percent).

MEXICO

Mexico is also a natural gas producer, with an indigenous production of 31 Mtoe in 1999. It also imports and exports small amounts of gas to and from the United States. Currently, domestic natural gas demand is growing more quickly than production. However, the better part of the market lies in the north and central part, while most of resources are located in the south.

A major constraint on natural gas development in Mexico has been the lack of pipelines, and lack of investment in this infrastructure, to transport gas over long distances. The demand centre is located more in the north, while the gas fields are in the south (offshore of the Yucatan peninsula). New pipelines are planned, however, especially trans-border connections linking Mexico to the United States.

A consortium of gas and power companies in Mexico and the United States is planning one Mexico-US cross-border pipeline. The pipeline, of 76 mm (30 inches) diameter, 11.2 MCMD, and 340 km, will connect the US and Mexican natural gas grids, beginning with an interconnection with El Paso Natural Gas Company in Arizona, running through southeastern California and northern Baja California to connect with the Rosarito Pipeline, south of Tijuana. This 'North Baja' pipeline will fuel a power plant that is currently powered by oil as well as a suggested gas-fired power station in the region. Baja California currently is experiencing rapid energy demand growth, much of which is served with US gas. The gas pipeline is expected to come on-stream in 2003.

In 1999, Mexico utilised 10,180 ktoe (32.9 percent) of its gas as fuel in the industrial sector. Another 1,064 ktoe (3.4 percent) was used as feedstock in petrochemical industries. The power sector consumed 9,283 ktoe (30.0 percent). The residential/commercial sector also consumed a small amount, 796 ktoe (2.6 percent). The remainder of the gas was consumed by the oil and gas sector.

THE UNITED STATES

The United States is the world's biggest natural gas consumer. Its proven gas reserves (at 4,738 BCM) account for 3.2 percent of the world total and rank it sixth in the world in proven reserves. In 1999, total US gas consumption exceeded its supply by 16 percent, and this shortfall was met almost entirely by Canadian imports. To meet rapid demand, since 1998 there has been a surge in pipeline expansion and construction. The most recent trunk line operating is the Alliance Pipeline, which was completed in December 2000, bringing gas from western Canada to the Chicago area, with a capacity of 36.4 MCMD. (Please refer to APERC report 2001, "Natural Gas Infrastructure Development in the APEC Region" for more information about the gas infrastructure development in the United States).

Recently, gas prices in the US have tended to fluctuate more than in the past. Wellhead gas prices averaged over US$6.00/mcf during the first quarter of 2001, a sharp rise from the US$3.62/mcf average price in 2000, and almost triple the average US$2.08/mcf price in 1999. During winter 2000/2001, natural gas wellhead prices averaged around US$5.74/mcf, spiking to US$10.00/mcf at one point. Several factors, some of them short term, contributed to a sharp reversal of a downward trend in gas prices during the previous decade: 1) gas production in the US fell from 1994 to 1999, partly due to declining prices; 2) demand for gas has increased, especially for power generation; 3) winter gas storage levels were below normal; 4) inevitable delay in response between production and arrival of new supplies to the market.

The consumption of gas in the US is widely diversified. In 1999, the residential/commercial sector consumed 181,003 ktoe (34.7 percent), the industrial sector 120,091 ktoe (23.0 percent), and the power sector 141,411 ktoe (27.1 percent). The transport sector also consumed a small proportion of 17,250 ktoe (3.3 percent). The 'Other' sector is also a large consumer of gas, accounting for 62,233 ktoe (11.9 percent), which was primarily consumed in the oil and gas sector and petroleum refineries.

NATURAL GAS CONSUMPTION IN SOUTHEAST ASIA

In Southeast Asian economies, natural gas has long been identified as an important energy commodity to reduce over-dependence on oil, and also to reduce the environmental impact of energy utilisation. For gas producing economies, efforts to produce and utilise their indigenous resources also adds to the economic value of their gas resources, and enables them to reduce their import and consumption of oil.

With the exception of Indonesia, gas-producing economies such as Brunei Darussalam, Malaysia and Thailand have made natural gas the dominant fuel for power generation. Its lower emission of pollutants, the increasing thermal efficiencies of combined cycle gas turbines, their relatively low initial investment compared with other fossil-fired plants, and their small-scale availability (such as 300 MW capacity) have made natural gas-fired plants a convenient and practical choice in keeping up with annual demand for electricity in these economies. Power generation in Brunei Darussalam is almost entirely dependent on natural gas. Malaysia has completely turned around its power generation scenario, from 70 percent oil-dependent in the mid-1980s to 71 percent gas-dependent in 1999. Thailand, which consumes all of its gas production, has also increased its gas share in the power sector, from 53 percent in the mid-1980s to 61 percent in 1999.[1]

A big challenge lies ahead in these economies that are trying to diversify the use of natural gas to other sectors, especially the industrial sector. Different economies are at different stages in

[1] APEC Energy Overview (2001)

pursuing this strategy, each having their constraints, especially in the current situation where economic uncertainties arise due to the recession that is sweeping across the globe.

Table 2 shows a summary of gas utilisation across sectors in the APEC economies of Southeast Asia. More details of the natural gas situation in Southeast Asia are given below. APERC reports published in March 2000 (Natural Gas Pipeline Development in Southeast Asia) and in March 2001 (Energy Supply Infrastructure Development in the APEC Region) provide fairly detailed scenarios on natural gas development in Southeast Asian economies. Some updates are provided here, with a particular focus on gas consumption.

Table 2 Sectoral gas consumption in Southeast Asia in 1999, ktoe

	Electricity	Industry Sector	Residential and Commercial	Transport Sector	Non-energy (Fertilisers and Petrochemical Feedstocks)	Other	Total Consumption
BD	820 (83.2%)	0	0 (0.0%)	0	0	165 (16.8%)	985 (100%)
INA	5,854 (21.0%)	1,083 (3.9%)	526 (1.9%)	0	5,488 (19.7%)	14,878 (53.5%)	27,829 (100%)
MAS	10,138 (61.1%)	1,701 (10.3%)	12 (0.1%)	0	1,005 (6.1%)	3,727 (22.5%)	16,583 (100%)
RP	6 (100.0%)	0	0	0	0	0	6 (100%)
SIN	1,423 (100.0%)	0	0	0	0	0	1,423 (100%)
THA	11,052 (73.5%)	864 (5.7%)	0	5 (0.0%)	154 (1.0%)	2,953 (19.6%)	15,028 (100%)
VN	743 (80.8%)	0	0	0	0	177 (19.2%)	920 (100%)

Note: 'Other' includes agriculture and other transformation and statistical discrepancies

Source: IEA (Non OECD) Energy Balance Tables (2001)

BRUNEI DARUSSALAM

Brunei Darussalam has 390 BCM of proven gas reserves. In 2000, total gas production was 11.6 BCM, of which 7.71 BCM (66.5 percent) was exported to Japan and 1.08 BCM (9.3 percent) was exported to Korea.[2] Japan, which started to import gas from Brunei Darussalam in 1972, currently takes 88 percent of this economy's LNG exports. This is based on Brunei Darussalam's long-term contract with Japan, which was renewed in 1993. Brunei Darussalam hopes to increase its LNG production and exports to a more significant level in the coming years.

In November 2001, Brunei Darussalam officially established its state-owned oil and gas company entrusted with exclusive ownership, exploration and production rights. Future operations will be in the form of production-sharing contracts (PSC) with other international players, after decades of operations based on concessions.

Long-term prospects for gas development in Brunei Darussalam are good. Brunei LNG (BLNG, a 50-50 joint venture between Mitsubishi and Brunei Shell) hopes to add 322 BCM (11.5 TCF) of gas to meet its expansion plans, including the addition of a new, four-million-tonnes-per-year gas liquefaction train at the Lumut facility by 2008. Brunei Darussalam is planning to expand its current fleet of seven specially designed LNG tankers. Besides exports, this economy has plans to use its natural gas to develop domestic petrochemicals and energy-intensive industries (such as aluminium smelting).

Local consumption in 1999 stood at 985 ktoe, of which 820 ktoe (83.2 percent) is consumed as fuel for electricity generation. In fact, Brunei Darussalam is fully dependent on natural gas for its

[2] BP Statistical Review of World Energy (2001)

electricity, with only one percent of the electricity generated from diesel. The balance (16.8 percent) of gas is used in other sectors.

INDONESIA

Indonesia has the biggest gas resources in the region. Its proven reserves in 1999 were listed at 2,156 BCM, slightly less than the proven reserves of Malaysia (2,430 BCM), but its 'gas resources' were listed at 8,312 BCM.[3] 'Gas resources' here refers to Indonesia's resource estimates, likely to change to 'proven' with more explorations in the future.

Indonesia is a leading exporter of LNG. In 2000, it produced 63.9 BCM of gas, of which 35.7 BCM (55.9 percent) was exported. Out of these exports, 24.25 BCM (68.0 percent) went to Japan, 8.35 BCM (23.4 percent) to Korea and 3.1 BCM (8.6 percent) to Chinese Taipei.

Despite large reserves, domestic gas demand is still limited. A high production-to-reserves ratio, however, has raised concerns that Indonesia is depleting its natural gas resources. The recently developed West Natuna gas field in the South China Sea is thought to hold reserves of 1,303 BCM and improves the gas situation in Indonesia, but the gas production was targeted for export. In January 2001, gas exports via pipeline from West Natuna to Singapore began to flow. The large gas fields in East Natuna (1,260 BCM) and West Irian Jaya (403 BCM) are not yet developed for various reasons. East Natuna gas is costly to develop because of its high carbon dioxide content (about 78 percent), while the Irian Jaya's gas, despite its higher methane content, lies at the extreme end of the Indonesian archipelago, distant from the demand areas.

Domestically, gas is used mostly for electricity generation, and as feedstock in petrochemical and fertiliser plants. Gas pipelines are available, but are mostly limited to short distances from gas fields to direct consumers. More integrated trans-island pipelines, such as connecting Sumatra to Java, Kalimantan to Java, and Java to Bali, are planned but their implementation has been delayed due to economic difficulties since the 1997-98 financial crisis.

MALAYSIA

Malaysia possessed 2,430 BCM of proven natural gas reserves in 1999.[4] Its production has been rising steadily over the last decade, reaching 32,942 ktoe in 1999, double that in 1989. Of this production, 15,485 ktoe (47 percent) was exported to Japan, Korea and Chinese Taipei, in the form of LNG, with Japan taking about 70 percent. Exports dipped slightly in 1998 as a result of the Asian financial crisis, but began to climb again in 1999. Since 1992, with the completion of the second phase of the Peninsular Gas Pipeline (PGUII), Malaysia began exporting natural gas to Singapore at a maximum daily rate of 150 MMCFD.

Malaysia accounted for approximately 17 percent of the world's total LNG exports in 1999, third after Indonesia (26 percent) and Algeria (19 percent). PETRONAS is proceeding with a long-planned expansion of its Bintulu LNG complex in Sarawak. Financing for the MLNG Tiga facility was completed in April 2001, and it is expected to begin operations in 2003. Letters of intent have been signed for output from the MLNG Tiga plant with several Japanese utilities. Though Malaysia is not a major supplier of LNG to the United States, occasional spot cargoes have been contracted by United States buyers.[5]

Malaysia may soon become an importer of gas from Indonesia. PETRONAS signed an agreement in April 2001 with Indonesian state oil and gas company PERTAMINA for the import of gas from Conoco's West Natuna offshore field in Indonesian waters. The move is being seen as another step towards Malaysia's strategy to become a hub for Southeast Asian natural gas integration. Deliveries are scheduled to begin once pipeline construction is complete in August

[3] APEC Energy Overview (2001)

[4] APEC Energy Overview (2001)

[5] EIA – USA DOE Annual Energy Review 2000

2002. The pipeline will connect to an existing pipeline from the shore to Malaysia's offshore Duyong field, which will help minimise construction costs. Negotiations are also taking place between PETRONAS and PERTAMINA for a possible pipeline gas supply from Sumatra to Peninsular Malaysia.

Domestically, gas is mostly used for power generation. The government is encouraging wider use of natural gas in all sectors, especially in the industrial sector. Currently, some gas is used as feedstock in petrochemical and fertiliser plants, and as fuel for natural gas vehicles. New big complexes (PETRONAS Twin Tower complex and the new KLIA airport) are also consuming natural gas for cogeneration systems, with the exhaust heat utilised for absorption-cycle central air-conditioning systems.

In 1999, Malaysia's natural gas consumption as fuel for the industrial sector was 1,701 ktoe, which was 10.3 percent of the total gas consumption. An additional 1,005 ktoe (6.1 percent) was used in industry as feedstock to petrochemical and fertiliser plants. The power sector consumed most of the gas, 10,138 ktoe (61.1 percent). A small amount of gas, 12 ktoe (0.1 percent) was used in the residential/commercial sector. Malaysia also uses significant amounts in LNG plants.

SINGAPORE

Singapore is the only economy in Southeast Asia that does not have its own indigenous energy resources. All its energy requirements are imported. The economy is heavily dependent on oil, and the government is actively working to diversify energy supply. Since 1992, piped gas from Peninsular Malaysia has been used for electricity generation as a first step towards energy supply diversification.

Gas imports from Indonesia were introduced in January 2001, after a 656-km pipeline from Indonesia's West Natuna gas field was completed in December 2000. The contract volume agreed between Indonesia and Singapore delivered by this pipeline was 9.1 MCMD. The pipeline was designed for a flow capacity of 19.6 MCMD and maximum capacity of 28 MCMD (with an upgrade), suggesting Singapore may import more gas from Indonesia in future with this pipeline.

In September 1999, Singapore Power (SP) signed a gas purchase agreement (GPA) with Indonesia's PERTAMINA for the supply of natural gas from the Jambi area in Central Sumatra, starting in 2002. The gas supply will increase from an initial 4.2 MCMD (150 MCFD) in 2002 to 9.8 MCMD in 2008. The pipeline will be routed through Batam, an industrially active Indonesian island located southeast of Singapore.

With more imports of natural gas, and from different sources, Singapore's gas industry is being restructured by separating the ownership of the gas transport business, which is a natural monopoly, from the contestable sectors of gas imports, trading and retailing. The gas distribution and transmission network will be owned by a gas grid company, PowerGas Ltd, which will allow players open and non-discriminatory access to the network.

All of the gas imports from Malaysia since 1992 have been used for power generation. With the supply contract ending in 2007, no indication has been given by either economy of whether the gas purchase contract will be extended. Gas imports from West Natuna are also principally used for power generation – three IPPs (SembCorp Co-Gen, Tuas Power and PowerSeraya) were established to utilise this gas supply as fuel for power generation. The gas from Sumatra is also planned to be used mostly for power generation.

THAILAND

Thailand is another Southeast Asian economy that is well-endowed with oil and natural gas reserves, but they are produced for domestic consumption. In 1999, Thailand's proven gas reserves stood at 346 BCM. Thailand had been largely self-sufficient in gas, unlike with oil. Since 2000, however, higher demand for natural gas has prompted Thailand to start importing it from Myanmar, after the completion of a gas pipeline from Myanmar's Yadanna field.

Most of Thailand's gas comes from Bongkot field, located 640 km south of Bangkok in the Gulf of Thailand. Domestically, gas production increased by eight percent in 1999 due to the additions of new offshore fields, Benchamas, Trat, and Pailin. Several offshore gas reserves have been reported in recent years, including natural gas offshore development in the Thailand-Malaysia Joint Development Area (JDA) and two additional natural gas and condensate production fields in the Gulf of Thailand, the Pladang and the Plamuk fields. In 1998, Pladang supplied 0.391 BCM of natural gas and 596,182 barrels of condensate, and Plamuk supplied 0.130 BCM of natural gas and 33,297 barrels of condensate.

Natural gas is used largely for electricity generation as well as feedstock to its petrochemical plants. Out of the 15,028 ktoe consumed in 1999, 11,052 ktoe (73.5 percent) of the gas was taken up by the power sector, and 5.7 percent (864 ktoe) by the industrial sector. For many years Thailand has been promoting use of natural gas vehicles in Bangkok to reduce pollution. In 1999, consumption for natural gas vehicles was still small at five ktoe.

VIET NAM

Viet Nam's natural gas industry is relatively small, with gas reserves estimated at 617 BCM, according to national sources. The BP Statistical Review, however, recorded Viet Nam's proven gas reserves at 190 BCM at end of 2000. Indigenous production in 1999 amounted to 920 ktoe (1,022 MCM), all of which was consumed domestically. Natural gas consumption is rising steadily, with further increases expected as additional fields come onstream. To date, Bach Ho is the biggest offshore field producing gas, with reserves estimated at 170-230 BCM. An existing 100-km pipeline from the Bach Ho field is operating near peak capacity. The Ruby and Rang Dong oil fields, both of which have considerable amounts of associated natural gas, are near the pipeline. However, the Bach Ho pipeline has insufficient capacity to carry gas from these fields, so much so that undelivered gas from these fields currently is flared.

A joint-venture between BP Amoco (UK), Statoil (Norway), and ONGC (India) has been formed with the national oil and gas company PetroVietnam to develop gas resources in the Nam Con Son basin's Lan Tay and Lan Do fields. A new 370-km pipeline will connect the fields to Viet Nam mainland at Vung Tau.

Almost all the gas produced in Viet Nam is used in the power sector (743 ktoe). The industrial zones mostly use LPG, and will switch to natural gas when it is available. In northern Viet Nam there is some use of natural gas by small enterprises, but the amount is negligible.

NATURAL GAS CONSUMPTION IN NORTHEAST ASIA

Natural gas utilisation in Northeast Asia is a mixed scenario. With few indigenous energy resources of their own, economies such as Japan, Korea and Chinese Taipei are dependent on imported oil, coal and natural gas. Global concerns to mitigate greenhouse gases are pushing Japan, Korea and Chinese Taipei to anticipate higher demand for natural gas in the future, posing better market opportunities for gas producing economies in Southeast Asia.

China's energy demand is second only to that of the United States. For now, coal is the dominant fuel in China. It is a gas producing economy, with future demand likely to increase far beyond its reserves. Its gas self-sufficiency policy, however, is stalling plans for natural gas pipelines from Russia, which has the world's largest natural gas reserves. Table 3 shows a summary of natural gas consumption in Northeast Asia. More information is provided on the gas situation in the respective economies.

Table 3 Sectoral gas consumption in Northeast Asia in 1999, ktoe

	Electricity	Industry Sector	Residential and Commercial	Transport Sector	Non-energy (Fertilisers and Pertochemical Feedstocks)	Other	Total Consumption
PRC	2,280 (8.7%)	6,351(24.4%)	4,849 (18.6%)	179 (0.7%)	4,466 (17.1%)	7,934 (30.4%)	26,058 (100%)
HKC	2,389 (100%)	0	0	0	0		2,389 (100%)
JPN	43,645 (70.3%)	8,510 (13.7%)	13,276 (21.4%)	0	0	-3,340	62,110 (100%)
ROK	5,578 (36.8%)	2,041 (13.5%)	7,182 (47.4%)	0	0	359 (2.4%)	15,160 (100%)
RUS	185,562 (59.0%)	23,180 (7.4%)	44,785 (14.2%)	30,726 (9.8%)	14,451 (4.6%)	21,479 (5.0%)	314,473 (100%)
CT	2,879 (54.7%)	560 (10.6%)	769 (14.6 %)	0	275 (5.2%)	782 (14.9%)	5,265 (100%)

Note: 'Other' includes agriculture and other transformation and statistical discrepancies

Source: IEA Energy Balance Tables (2001)

CHINA

In the last decade, China has become the world's biggest producer and consumer of coal, surpassing the United States. China was the world's seventh-largest oil producer and third-largest oil consumer in 1999. After decades as a net oil exporter, China became a net oil importer in 1993. In 1998, imports accounted for 32 percent of total crude oil and petroleum product requirements. Gas production and consumption in China are currently quite small at just three percent of total primary energy supply.

Proven gas reserves in China amount to 1,370 BCM, with a current reserves-to-production ratio sufficient for 49 years. While its gas resources are substantial, they are located mostly in its western part, far from the demand centres in large cities in the east, and hence full development of these gas fields would be uneconomical. In the last few years, however, Chinese authorities have begun to promote gas use in power generation and industry. The Chinese government is very concerned that its old coal-fired power stations could continue to cause pollution problems, especially in cities, and are making strenuous efforts to convert them to gas. China anticipates that its demand for natural gas will triple to 96.3 BCM by 2010.[6]

The government is investing in pipeline infrastructure, including a 'West to East' pipeline from Xinjiang (Uygur Autonomous Region) to Shanghai, to facilitate gas use. The US$12-15 billion pipeline is expected to stretch about 4,200 km, with a gas transmission capacity of 12 billion cubic metres in Phase I. It is expected that the pipeline project will stimulate investment in gas exploration and development, lead to the establishment of distribution networks and encourage increased gas use by industries. Some concerns have been expressed by potential foreign partners about the viability of this pipeline project. The concern stems from the possibility that Tarim Basin gas reserves will only last for 20 years, whereas 40 years of operation would be needed to make the pipeline profitable. The recent discovery of gas reserves (about 196 BCM) in the Ordos Basin in the Inner Mongolia Autonomous Region, through which the West to East pipeline would run, provides some reassurance that gas from this field feeding into the trunk pipeline could make the project economically feasible.

Another proposed pipeline long talked of would be across the border with Russia, to link the gas grid in Siberia to China and possibly also to Korea, with gas from the Kovykta fields near Irkutsk. China's policy of natural gas self-sufficiency has been the main reason why this proposal could not take off. The infrastructure would be expected to cost US$12 billion, with a planned

[6] Oil & Gas – China Profile, www.tradepartners.gov.uk/oilandgas/china/profile/overview.shtml

capacity of 81.2 MCMD, of which 53.2 MCMD would be taken by China and the remainder of 28 MCMD delivered to Korea.[7]

China also has off-shore gas projects. The Yacheng gas field, near Hainan Island, is China's largest off-shore natural gas field. It was developed in the mid-1990s and began supplying natural gas to Hong Kong, China and Hainan Island at the end of 1995. In 1997, Arco and the Chinese National Offshore Oil Corporation (CNOOC) started building an offshore pipeline from the Yacheng field to mainland China.

In China, natural gas consumption is primarily intended for the industrial sector and as feedstock in fertiliser plants. In 1999, 6,351 ktoe (24.4 percent) was consumed as fuel for the industrial sector and an additional 4,466 ktoe (17.1 percent) as feedstock in fertiliser plants. The power sector consumed only 2,280 ktoe (8.7 percent). The residential/commercial sector consumed 4,849 ktoe (18.6 percent).

HONG KONG, CHINA

Hong Kong, China does not have any indigenous energy resources. All the oil, natural gas and coal it needs are imported. Of its total primary energy supply of 16,345 ktoe in 1999, 60 percent was oil, 22 percent coal and 14 percent gas. Electricity imports from China accounted for the remaining four percent. The bulk of its electricity is generated domestically.

Towards the end of 1995, Hong Kong, China began importing natural gas brought by pipeline from the South China Sea offshore gas field of Yacheng. In 1996, Hong Kong, China opened its first gas-fired power plant. In 1999, a total of 2,389 ktoe of natural gas was consumed by the power sector.

JAPAN

Japan is the world's biggest importer of natural gas in the form of LNG, taking about 53 percent of the world's LNG exports in 2000. It has indigenous reserves of 39.6 BCM (in 1999). With such small reserves, domestic production is minimal, and local production supplies only three percent of total gas demand. The rest is imported. Natural gas accounted for 12 percent of Japan's total primary energy in 1999.

Japan's gas imports date back to 1969, when it began importing LNG from Alaska. Since then, gas consumption has grown rapidly. Total gas imports in 2000 totalled 72.46 BCM. Currently, 64.5 percent of the gas comes from Southeast Asia, of which Indonesia provides 33.5 percent, Malaysia 20.4 percent and Brunei Darussalam 10.6 percent. Other gas exporters to Japan are Australia (13.6 percent), Qatar (10.8 percent), the United Arab Emirates (8.7 percent), and Oman (0.1 percent). Alaska still continues to export LNG to Japan, though it has only a 2.3 percent share of imports.

To meet future demand, Japan is considering imports from Sakhalin, whose gas reserves are estimated to be around 740-944 BCM. Two projects are being considered. The Sakhalin 1 Project proposed by Exxon Neftegas (30 percent), together with SODECO (Sahkalin Oil & Gas Development Co. Ltd., 30 percent) and other companies (Rosneft 17 percent, Rosneft-Sakhalinmour-Heftegas 23 percent) are suggesting two pipelines, one for oil and the other for natural gas, to Niigata or Tokyo. This project is estimated to cost US$23 billion. The Sakhalin 2 Project proposed by Shell (25 percent) together with Marathon Oil (37.5 percent) and other companies (Mitsubishi 12.5 percent, Mitsui 25 percent) would involve oil and LNG shipments.

In 1990-99, gas consumption in Japan increased 46 percent, from 51.2 BCM in 1990 to 74.6 BCM in 1999. With its share in Japan's primary energy supply still small, demand for natural gas is expected to continue to rise. Japan is also expected to use natural gas as an important energy source in mitigating greenhouse gas emissions as well as improving air quality.

[7] US DOE (2000) Scenarios for Clean Energy Future – Office of Energy Efficiency

With gas demand continuing to increase, and supply available either from Sakhalin, Southeast Asia or other exporters, the government is planning to expand its domestic gas pipeline network. Although areas in and around Tokyo are well-served by the gas distribution system, much of Japan's other urban areas are not.

From the 62,110 ktoe of natural gas consumption in 1999, 43,645 ktoe (70.3 percent) was consumed in the power sector, 13,276 ktoe (21.4 percent) in the residential/commercial sector (mainly for space heating and cooking) and the balance 8,510 ktoe (13.7 percent) in the industrial sector.

KOREA

Korea has only recently discovered a commercially viable gas reserve (Donghae-1 field) on the continental shelf off Ulsan in southeast Korea. This field has recoverable gas reserves of 5.66 MMCM.[8] Korea's natural gas demand relies on imported LNG (since 1986) from the state-owned monopoly LNG importer Korea Gas Company (KOGAS). The LNG mainly comes from Indonesia and Malaysia, with smaller volumes from Brunei Darussalam, Qatar and Oman. Korea started to import gas from Qatar in 1999 and from Oman in 2000.

Korea's National Oil Company (KNOC) is planning to start its own small domestic production with the US$320 million Donghae-1 development project. The production capacity is small, however, and will satisfy only about two percent of Korea's gas demand when it comes onstream. Meanwhile, KOGAS is pushing ahead with projects for the expansion of its existing LNG receiving terminals at Pyongtaek and Inchon. A third LNG terminal at Tongyong is still under construction, and is scheduled to be completed in 2002. The project is developed by Mitsubishi Corporation of Japan and Pohang Iron and Steel Corporation of Korea. Two other LNG terminals are being planned with project periods of 2003-05 and 2006-10. When these three LNG terminals are completed, Korea will have an additional 3,700,000 kilolitres of LNG storage facilities. Current LNG imports of Korea stand at 19.68 BCM[9], with a total of 10 LNG storage tanks at Pyongtaek and Inchon, each with 100,000 kilolitres storage capacity.

Korea has a comprehensive network of domestic gas pipelines connecting the LNG terminals and the main cities. The trunk pipelines are owned and operated by KOGAS, whereas smaller pipelines feeding gas to consumers (power stations, industries and residential/commercial users) are separately operated and owned by the consumers themselves. New pipelines are under construction connecting the new terminal at Tongyong to the existing pipeline network.

Most of the natural gas in Korea is used in the residential sector, in particular for space heating, and in the power sector. In 1999, 7,182 ktoe (47.4 percent) of imported gas was utilised in the residential/commercial sector, 5,578 ktoe (36.8 percent) as fuel in the power sector, and 2,041 ktoe (13.5 percent) as fuel in the industrial sector.

CHINESE TAIPEI

Chinese Taipei does not have any significant energy resources. Out of its 79,925 ktoe total primary energy supply in 1999, only 15 percent was met by indigenous production, and the other 85 percent was imported. Natural gas made up only 6.6 percent of its primary supply, and most of this was imported in the form of LNG from Indonesia and Malaysia. Chinese Taipei is implementing plans to promote more gas-fired power plants, signalling more imports of natural gas in future. Three firms have signed power purchase agreements (PPA) with the Taiwan Power Company (TPC) for total generation of 1,950 MW. The Electricity Law is also being revised, paving the way for liberalising the power industry, gradually enabling consumers to purchase electricity from any utility in the future.

[8] APEC Energy Overview (2001)

[9] BP Statistical Review of World Energy (2001)

Currently, of its total gas consumption, 2,879 ktoe (54.7 percent) was consumed in the power sector, 560 ktoe (10.6 percent) as fuel in the industrial sector and 769 ktoe (14.6 percent) in the residential/commercial sector. A small amount, 275 ktoe (5.2 percent) is used as feedstock in the petrochemical industry.

RUSSIA

Russia is one of the APEC economies highly endowed with energy resources. With 48.14 TCM, Russia possesses the world's largest proven reserves of gas – accounting for 32.1 percent of the world total in 2000. The economy is also endowed with 4.6 percent of the world's proven oil reserves (6.7 billion tonnes in 2000) and 15.9 percent of the world's coal reserves (157.01 billion tonnes in 2000). It also has economic potential for hydropower estimated at 852 TWh per year, almost 20 percent of which has been developed. Uranium ore in Russia comprises about 14 percent of the world total.

Natural gas production in 1999 totalled 551 BCM. This is the biggest production by any single economy, though only slightly above the US figure of 540.5 BCM. Domestic consumption accounts for about 66 percent of the production. The balance is exported, by pipelines, to Western and Eastern European countries, and to the Commonwealth of Independent States (CIS). Germany, Italy and France are the biggest importers, taking 34.80 BCM (27.7 percent), 19.10 BCM (15.2 percent) and 11.96 BCM (9.5 percent) respectively. Other importing countries include the Czech Republic at 7.8 BCM (6.2 percent), Slovakia 7.4 BCM (5.9 percent) and Slovenia 0.53 BCM (0.4 percent).

Russia also has significant gas reserves in Eastern Siberia, but inadequate investment and lack of full commitment to develop the reserves remain a barrier to development. While the West Siberian gas fields are well developed and have many customers, the plan to deliver Eastern Siberian gas to China, Japan and possibly to Korea has not been finalised yet with China consistently sticking to its gas self-sufficiency policy. China is expected to be the biggest uptake of gas from the Eastern Siberia gas fields, and without China's commitment to import any gas from Russia, the proposed long-distance pipeline from East Russia to China, Korea and Japan cannot be economically viable.

Domestically, 185,562 ktoe (59.0 percent) of the gas is consumed in the power sector, followed by 23,180 ktoe (7.4 percent) used as fuel in the industrial sector, 44,785 ktoe (14.2 percent) in the residential/commercial sector and 30,726 ktoe (9.8 percent) in the transport sector. Gas used as feedstock in petrochemical industries amounted to 14,451 ktoe (4.6 percent).

NATURAL GAS CONSUMPTION IN OCEANIA

The APEC Oceania economies consist of Australia, New Zealand and Papua New Guinea. All three produce natural gas, with the latter just beginning to develop its upstream production capacity. Australia has already joined the other Southeast Asian economies as an LNG exporter, exporting its gas to Northeast Asia, while New Zealand's production is geared to meeting domestic needs.

Table 4 shows a summary of natural gas consumption across all sectors of these economies.

Table 4 Sectoral gas consumption in Oceania in 1999, ktoe

	Electricity	Industry Sector	Residential and Commercial	Transport Sector	Non-energy (Fertilisers and Petrochemical Feedstocks)	Other	Total Consumption
AUS	3,976 (21.8%)	6,687 (36.7%)	3,559 (19.5%)	265 (1.5%)	315 (1.7%)	3,405 (18.7%)	18,207 (100%)
NZ	1,986 (41.3%)	570 (11.9%)	250 (5.2%)	8 (0.2%)	1,861 (38.7%)	133 (2.8%)	4,808 (100%)
PNG	113 (100.0%)	0	0	0	0	0	113 (100%)

Note: 'Other' includes agriculture and other transformation and statistical discrepancies

Source: IEA Energy Balance Tables (2001) for Australia and New Zealand and APEC Energy Statistics (2000) for PNG

AUSTRALIA

The discovery of natural gas in commercial quantities in the 1950s and 1960s marked the start of the rapid development of the natural gas industry in Australia. Demand for natural gas rose from a negligible amount in 1968 to over 18 Mtoe in 1999. Reserves of natural gas in Australia have also increased markedly over that period and currently are around 1,260 BCM (1,174 Mtoe), with most of its resources of natural gas located offshore, in the west and north. Production of natural gas in 1999 was 27,064 ktoe, of which 8,857 ktoe was exported as LNG.

Historically, the Australian gas market has been characterised as a regional one. Such markets have limited pipeline interconnections, are supplied by a single joint venture producer and a single (usually government-owned) transporter/retailer. This is mainly due to natural gas resources being a long distance from major consumption centres, and to historical energy policies of state governments.

Over the last 10 years the energy sector in Australia, due to a microeconomic reform agenda, has undergone significant changes in order to enhance its efficiency. In 1994, the Council of Australian Governments (COAG) committed itself to achieving 'free and fair trade' in natural gas. Previous state government impediments to interstate trade had effectively reduced exploration and production levels.

In recent years there has been an integration of regional gas markets through the construction of new gas pipelines and the removal of regulatory barriers to interstate trade in gas, together with increased vying for customers in retail markets. As a result of the reforms, the transport and retailing of natural gas has moved from being mainly state owned to a combination of public and private enterprises. These are generally either separately owned or operated as 'ring fenced' entities (separate legal and/or accounting entities within a larger enterprise). The majority of transmission pipelines are privately owned, and a growing number of retail assets are also privately owned.

Reforms have focused on promoting and enhancing access to competitive gas supplies for all customers, while addressing the natural monopoly aspects of transport in the gas industry. There are three distinct pipeline networks in Australia, with separate networks in Western Australia and the Northern Territory and an interconnected network in South Australia, Victoria, New South Wales, the Australian Capital Territory and Queensland. Additional interconnections are being developed, with a number of major gas pipelines and extensions recently completed or under construction. There are also proposals for new major pipelines.

Gas transmission in Australia has historically developed largely within state boundaries, but in recent years a number of interconnectors have seen the advent of competition among fields. There are also a number of major new gas transmission pipelines that could see large gas fields in Papua New Guinea and/or the Timor Sea connected to the Australian natural gas network. The advent of these connections would see increasing competition in the gas market, resulting in lower prices for end-users. The introduction of these pipelines would also see new markets for natural gas opening through fuel substitution and 'green field' projects and/or industries such as Direct Reduced Iron (DRI), alumina, magnesium production, etc.

The Australian natural gas industry operates a total of 89,000 km of pipelines, made up of approximately 71,000 km of distribution network and 18,000 km of transmission pipelines, and has been growing at a rate of 2,000-3,000 km a year over the last five years.

There are four natural gas storage sites in Australia, located in the Cooper/Eromanga Basin at Moomba in South Australia, the Surat Basin at Newstead in Queensland, the Perth Basin at Mondarra in Western Australia, and the Western Underground Gas Storage at Iona in the Otway basin in Victoria. Currently, natural gas storage in Australia is mainly used in preparation for winter peak loads.

Natural gas demand has grown strongly since its inception, and by 1998-99 demand had increased to 18,207 ktoe or 17 percent of Australia's total primary energy supply. This increase in the share of natural gas was at the expense of petroleum products, whose share of total primary energy supply fell from over 50 percent to 33 percent over the same period. The substitution of natural gas for petroleum products occurred primarily in stationary applications such as boilers, kilns, and driers in the industrial sector, and heating, cooking, and hot water in the commercial and residential sectors. The use of natural gas for electricity generation also increased sharply and by 1998-99 accounted for almost nine percent of thermal fuel input.

Gas production in 1999 amounted to 30.6 BCM, of which 10.11 BCM (33.0 percent) was exported. In terms of quantity, Australia ranks fifth (after Indonesia, Malaysia, Algeria and Qatar) among the world's LNG exporters, with its exports going to Japan (97 percent), the US (2.3 percent) and Korea (0.7 percent).

Coal accounts for the biggest part of energy supply in Australia at 46.8 percent. The share of natural gas in the fuel-mix of the economy is only 16.7 percent. In 1999, gas consumption in Australia was split into 6,687 ktoe (36.7 percent) in the industrial sector, 3,976 ktoe (21.8 percent) in the power sector, and 3,559 ktoe (19.5 percent) in the residential/commercial sector. There was some gas consumption in the transport sector at 265 ktoe (1.5 percent), while 3,405 ktoe (18.7 percent) was consumed in the oil and gas sector and oil refineries.

NEW ZEALAND

Natural gas reserves in New Zealand amount to 164.5 BCM. At the current rate of production (4,808 ktoe in 1999) the gas will last until 2014. Currently the gas is only distributed in the Northern Island, with eight fields operating. The Maui field dominates production, with 78 percent of New Zealand's oil and gas gross output coming from this field. The Maui field is expected to be exhausted by 2006, however.

Gas contributes 27 percent of New Zealand's total primary energy consumption. With no plans for future imports of natural gas when its indigenous reserves are exhausted, it is expected that coal and renewables (such as wood, wastes, biogas and wind) will have an increasing role in New Zealand's energy mix.

The Natural Gas Corporation Limited (NGC) operates the gas transmission network and owns two-thirds of the 2,600 km of high-pressure gas pipelines. There are five gas distribution companies and six retailers in New Zealand.

Gas use is well-diversified in New Zealand. Two major gas consuming sectors are power and chemicals, consuming 1,986 ktoe (41.3 percent) and 1,861 ktoe (38.7 percent) respectively in 1999. The industrial sector consumed 570 ktoe (11.9 percent) in 1999. Gas consumption by the transport sector was 8 ktoe (0.2 percent).

PAPUA NEW GUINEA

PNG has natural gas fields with total estimated reserves of 397 BCM. Most of the reserves are located onshore in the Hides gas field (near the northern border with Irian Jaya in Indonesia) with reserves estimated at 112 BCM. The Kutubu oil field (located 96 km southeast of the Hides field) also provides associated gas with estimated recoverable reserves of 56 BCM. Currently, only a small amount of gas is produced (113 ktoe in 1999), which is used for power generation.

Papua New Guinea is mostly dependent on oil. The economy is negotiating to sell most of its gas to Queensland, Australia.

NATURAL GAS CONSUMPTION IN LATIN AMERICA

Table 5 shows how natural gas is used in the two APEC economies of Latin America. Chile's industrial sector accounted for 7.1 percent of natural gas consumption in 1999, while the power sector consumed 23.6 percent and the residential and commercial sector 4.7 percent. The transport sector had a share of 0.1 percent.

Both of these economies are projected to considerably increase their natural gas consumption. In the case of Chile, supply comes mainly from Argentina. In Peru, the Camisea field will boost production in 2004.

Table 5 Sectoral gas consumption in Latin America in 1999, ktoe

	Electricity	Industry Sector	Residential and Commercial	Transport Sector	Non-energy (Fertilisers and Petrochemical Feedstocks)	Other	Total Consumption
CHL	1,141 (23.6%)	345 (7.1%)	229 (4.7%)	6 (0.1%)	0 (0.0%)	3,124 (64.5%)	4,844 (100%)
PE	0	0	0	0	0	647 (100.0%)	647 (100%)

Note: 'Other' includes agriculture and other transformation and statistical discrepancies

Source: IEA (Non-OECD) Energy Balance Tables (2001)

CHAPTER 3

NATURAL GAS USE IN INDUSTRIES IN NORTH AMERICA

INTRODUCTION

This chapter deals with natural gas consumption in the industrial sector of the North American APEC economies of Canada, Mexico and the US. As described in Chapter 2, these three have been able to utilise natural gas across a wider sector of their economies, with the industrial and residential/commercial sectors dominating the use of gas for Canada and the United States, and the industrial and power sectors dominating for Mexico. Such levels of high penetration of natural gas in these economies have been enabled by two main factors - an extensive infrastructure network and the liberalised gas market especially in Canada and the US.

In North America, where gas resources are mostly onshore and the market centres are diverse and scattered, the pipeline system is the more economical and convenient option for transporting gas from the fields to end-users. Natural gas from the wellhead is often processed and moved into a pipeline system for transport to the market where it is sold to end-users. The gas transmission system in the United States alone is a network of over 480,000 km of piping, excluding local distribution lines. Mainly made of steel, and of 500-1,050 mm in diameter, these pipelines transmit gas at high pressures of 14-100 bars, with the pressure level maintained by compressing the gas periodically (usually reciprocating compressors) installed at intervals of 160 km along the pipeline route. In the United States, major investments in the pipeline system were made during the 1980s, and in the early 1990s the system's capacity was further improved to areas in the northeast, the West Coast and Florida.

Gas storage centres are another important part of the gas infrastructure system. When natural gas reaches its destination through pipeline transmission, it is often stored prior to distribution. Storage acts as a sort of buffer between the pipeline and the distribution system, and allows distribution companies to serve their customers more reliably by withdrawing more gas from storage to meet customer demand during either peak use or ordinary use. Local storage of gas helps meet energy demand whenever it arises. It also allows the sale of fixed quantities of natural gas in spot markets (demand) and in off-peak periods as well. There are more than 380 underground storage sites in 27 states across the US and Canada and these sites can hold upwards of 780 MCM (million cubic metres) of natural gas, ready to be withdrawn at any time. Despite these high numbers, storage capacity is always increasing in order to accommodate increased gas usage and improve reliability.[10]

In the United States, changes in the structure of the natural gas industry have been caused mainly by deregulation over a period of almost 15 years. In 1985, the Federal Energy Regulatory Commission (FERC) began the first of a series of regulatory actions designed to improve the market's competitiveness. A more competitive market gives customers of the interstate pipeline companies more service options and allows the ultimate consumers to benefit from the deregulation of wellhead prices. The process of change culminated with the release of FERC Order 636 in 1992. Pipelines, which once functioned as both sellers and transporters of gas, now are primarily transporters. Therefore, producers, pipeline affiliates, distributors and marketers can all play a larger role in supplying natural gas to end users. Distributors, too, have been significantly affected. While many are still regulated to some extent by their state or local governments, they have been given increasing flexibility to be more responsive to the needs of their large-volume customers. Most distributors now offer unbundled services, which allow a larger end user to select the most cost-effective and efficient mix of supply, transport, storage, backup and other services.

[10] www.naturalgas.org

Gas marketing firms also emerged in the 1980s in response to the deregulation of prices. These service providers, often with no ties to any gas company, can serve as an intermediary between a gas buyer and all other segments of the industry.

NATURAL GAS APPLICATIONS IN INDUSTRIES

FUEL/THERMAL USE

Natural gas consumption for fuel and for thermal use varies widely among industries, as shown in Table 6, Table 7 and Table 8 for Canada, Mexico and USA, respectively. These tables provide five-year data since 1980, as an illustration of the types of industries using natural gas. The IEA Energy Balance Tables (2001), from which this data is derived, provide longer historical series going back to 1960. For the United States, a breakdown of gas use by industry is not available until 1995.

The usual grouping of industries utilising natural gas includes iron and steel plants, chemical and petrochemical plants, non-ferrous plants, non-metallic plants, mining and quarrying industries, paper, pulp and printing, and the construction industry. These are industries where use of energy can be considered significant – non-specified industries include other industries that are not particularly categorised, or where the use of gas (and other fuels) is not particularly identified. Between these industries, iron and steel and the chemical and petrochemical industries are usually categorised as energy-intensive industries.

The United States, being a bigger economy, has a bigger iron and steel industry than the other two, with natural gas utilisation in this industry more than five times that in Canada and Mexico. The chemicals and petrochemicals industry is another that uses a relatively high amount of natural gas either for heating processes or as fuel in cogeneration systems from which electricity is used locally and the heat generated utilised for the petrochemical processes. Note that Table 6, Table 7 and Table 8 include gas use data as feedstock, which are inclusive of total gas use in chemical and petrochemical plants. Subtracting gas feedstock data from the gas consumption data for the chemical and petrochemical industry from these tables would give us the gas consumed directly for fuel or processes. It should be noted that Canada and Mexico, which are gas producers and net exporters, use natural gas for both fuel/process and feedstock.

AS FEEDSTOCK TO PETROCHEMICAL AND FERTILISER INDUSTRIES

The petrochemical industry is a large consumer of natural gas in North America, being used as feedstock for the manufacture of chemicals and petrochemicals. Figure 2, Figure 3 and Figure 5 show that use of natural gas as feedstock in petrochemical plants in Canada, Mexico and the United States is even higher than the use of gas as fuel in the iron and steel industries. Most basic petrochemicals are manufactured or obtained from hydrocarbons commonly found in natural gas or cracked from petroleum refinery operations. One such major class of interest is olefins. Natural gas liquids account for more than 68 percent of the feedstock to olefins plants in North America. Ethylene is the main product of the petrochemical industry.

Also within the petrochemical industry, natural gas liquids and naphtha have been by far the preferred feedstock for ethylene synthesis. Naphtha, a derivate of the oil refinery process, is still the main feedstock for ethylene production, but may experience a long-term declining trend in favour of the new ethane derived from natural gas, with natural gas being more available in the market.

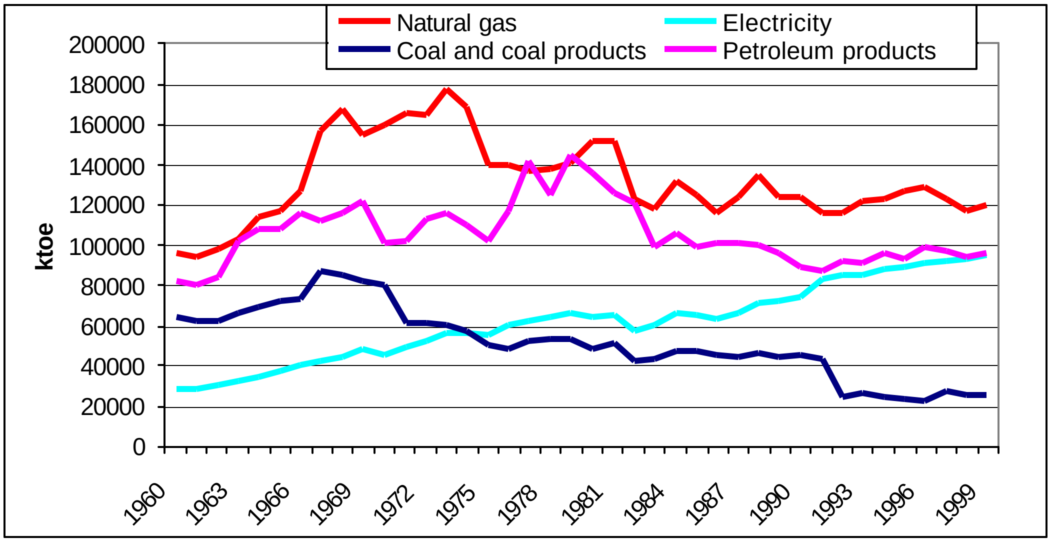
Historically, prior to World War II, coal and coke accounted for more than 90 percent of the estimated three million tonnes a year of nitrogen produced as ammonia.[11] By 1960, with an estimated world capacity of 10 million tonnes per year, natural gas overtook coal and coke as the main feedstock, mainly because of abundant cheap gas in the US. The US is also a large agricultural

11 Natural Gas – It's Role and Potential in Economic Development (1984)

economy and depends on good harvest for its food supply security. An adequate supply of fertilisers means more food production and hence more use of natural gas.

The trend of gas consumption as a feedstock in the petrochemical industries (including fertilisers) is a growing one in the US (Figure 5) whereas in Mexico it has been declining since 1993 to a level below the iron and steel industry's gas consumption of 2,000 ktoe in that year (Figure 3). Canada's gas as feedstock into its petrochemical industries had remained stable between 1984 and 1999, in quantities higher than iron and steel industry's share (Figure 2).

Figure 1 Energy consumption in industrial sector in USA by fuel types (1960-1999)



Source: IEA (OECD) Energy Balance Tables (2001)

SITUATION IN CANADA

As Table 6 suggests, natural gas is widely used in various industries, not only as fuel and for direct process, but also as feedstock in Canada's chemical and petrochemical plants. In 1999, total gas use in the industrial sector took up 44.2 percent (22,580 of 51,075 ktoe) of Canada's total final consumption. The industries that consume the largest amounts of natural gas in descending order are: chemical and petrochemical at 7,907 ktoe (35.0 percent of industrial consumption); paper, pulp and printing at 2,817 ktoe (12.5 percent); and mining and quarrying at 2,088 ktoe (9.3 percent). The iron and steel industry with 1,870 ktoe took 8.3 percent of industrial gas use. The non-specified industry accounted for nearly 29.2 percent of natural gas consumed in the industrial sector. Further break-up of gas use reveals 80.4 percent for fuel and processes and 19.6 percent for feedstock use.

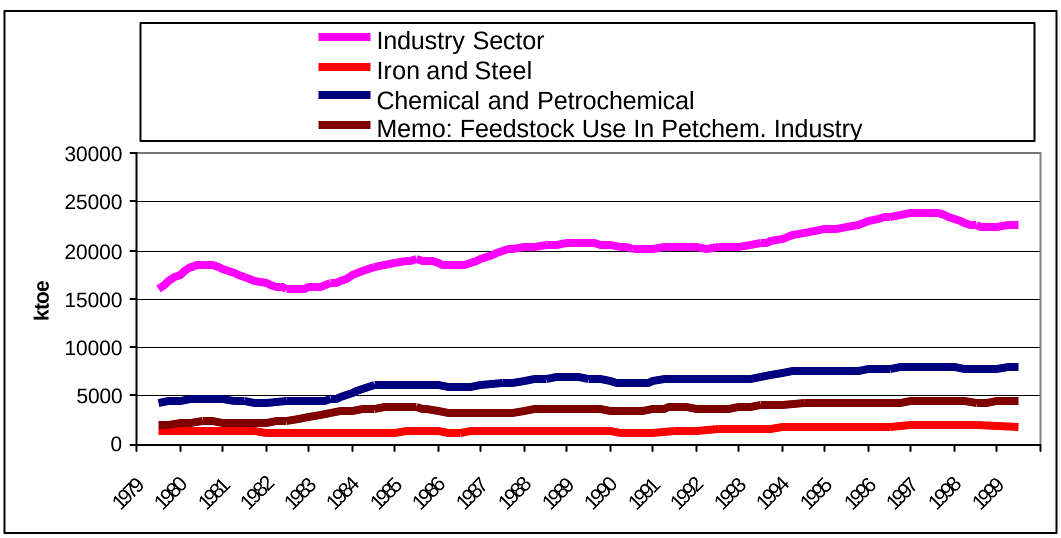
Table 6 Gas use in industries in Canada (1980-1999), ktoe

	1980	1985	1990	1995	1999
Total Final Consumption	36,223	41,418	43,301	50,747	51,075
Total Industry Sector	18,534	19,035	20,232	22,461	22,580
Iron and Steel	1,465	1,301	1,212	1,745	1,870
Chemical and Petrochemical	4,728	6,125	6,244	7,583	7,907
(Memo: Feedstock Use In Petrochem. Industry)	2,332	3,757	3,381	4,145	4,415
Non-Ferrous Metals	662	511	536	571	707
Non-Metallic Minerals	505	343	338	315	289
Mining and Quarrying	3,355	3,087	1,459	1,873	2,088
Paper, Pulp and Printing	1,719	1,759	2,469	2,922	2,817
Construction	0	0	420	267	317
Non-specified Industry	6,100	5,909	7,555	7,184	6,585

Source: IEA (OECD) Energy Balance Tables (2001)

Figure 2 shows the trend of natural gas consumption in Canada. Total consumption in the industrial sector experienced an annual average growth rate of 2.0 percent over the period 1979-99. Gas consumption in the iron and steel industry grew at an annual rate of 1.7 percent, and in the chemical and petrochemical industry it had an annual growth of 1.3 percent. Gas feedstock use in the petrochemical industry grew at an annual rate of 4.2 percent during the period.

Figure 2 Canada's natural gas consumption in industry by end use sub-sectors (1979-1999)



Source: IEA (OECD) Energy Balance Tables (2001)

SITUATION IN MEXICO

Like Canada, Mexico is a gas producer and exporter. Gas is widely used in various industries, not only as fuel and for direct process, but also as feedstock in Mexico's chemical and petrochemical plants. Table 7 shows that, in 1999, total gas use in the industrial sector accounted for 93.3 percent (11,244 of 12,047 ktoe) of Mexico's total final consumption. Mexico's three major natural gas-consuming industries that year were: chemical and petrochemical including non-energy use (59.0 percent - which when further broken down gives 49.5 percent for fuel and process, and 9.5 percent for feedstock); iron and steel (21.8 percent); and non-metallic minerals (7.5 percent). The share of the non-specified industry in industrial gas consumption was 10.7 percent.

Figure 3 shows the trend of industrial gas consumption in Mexico. The annual growth rate of natural gas consumption in the industrial sector over the period 1971-99 was 2.4 percent. Consumption growth in the iron and steel industry was 3.8 percent and shows a potential to increase further in the future. The growth rate of gas consumption in the chemical and petrochemical industry was 4.0 percent, and for gas used as feedstock was 3.1 percent.

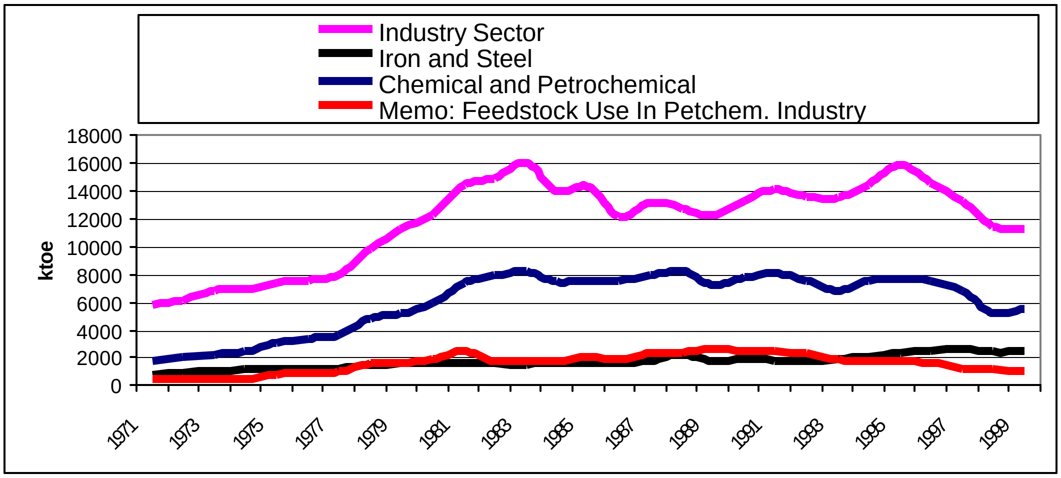
Total gas consumption increased rapidly between 1971 and 1983, explained mainly by the growth in gas used as fuel in the chemical and petrochemical industry. Between 1983 and 1993, growth remained fairly stable, with drops in 1986 and 1989. Gas consumption increased after 1993, reaching a peak in 1995 and falling below the 1993 level by 1997. The fluctuation in total gas consumption is attributable to changes in the chemical and petrochemical industries; gas used as fuel in the iron and steel industry remained fairly stable during these periods.

Table 7 Gas use in industries in Mexico (1980-1999), ktoe

	1980	1985	1990	1995	1999
Total Final Consumption	12,836	14,967	14,160	16,679	12,047
Total Industry Sector	12,366	14,334	13,350	15,930	11,244
Iron and Steel	1,597	1,651	1,917	2,393	2,449
Chemical and Petrochemical	5,903	7,596	7,780	7,737	5,570
(Memo: Feedstock Use In Petrochem. Industry)	1,912	2,092	2,526	1,778	1,064
Non-Ferrous Metals	18	45	38	78	94
Non-Metallic Minerals	971	949	740	742	844
Transport Equipment	114	98	42	45	78
Mining and Quarrying	317	251	406	614	644
Food and Tobacco	44	54	124	182	103
Paper, Pulp and Printing	306	395	341	435	257
Non-specified Industry	3,097	3,296	1,963	3,705	1,204

Source: IEA (OECD) Energy Balance Tables (2001)

Figure 3 Mexico's natural gas consumption in industry by end use sub-sectors (1971-1999)



Source: IEA (OECD) Energy Balance Tables (2001)

SITUATION IN THE US

In the United States, natural gas is also used over a wide range of industries. No historical data is available before 1995 for gas consumption by type of industry. As indicated in Table 8, in 1999, total gas use in the industrial sector took up 37.7 percent (120,091 of 318,344 ktoe) of the US's final gas consumption. The US industries that consume the largest amounts of natural gas in descending order are: chemical and petrochemical plants (38.1 percent), the food and tobacco industry (11.7 percent), and paper, pulp and printing (11.5 percent). No data is available, however, for the amount of gas consumed as feedstock in the chemical and petrochemical industries. The iron and steel industry accounts for 9.6 percent of industrial gas use. The machinery production and non-metallic mineral industries also take a fairly good share at 8.3 and 8.0 percent, respectively.

Consumption of petroleum products in the industrial sector declined between 1980 and 1983, but overall had a growth rate of 2.6 percent over the 39-year span (1960-99). Electricity use reflected some competitiveness with a growth rate of 2.9 percent and overtook petroleum products consumption in 1982. Some of this electricity is internally produced using cogeneration or non-utility generation (NUG) systems. Coal and coal products consumption declined gradually, with growth rates of minus 1.7 percent over the same period, indicating on the whole a shift by the US to a more environmentally benign fuel source in line with its environmental goals.

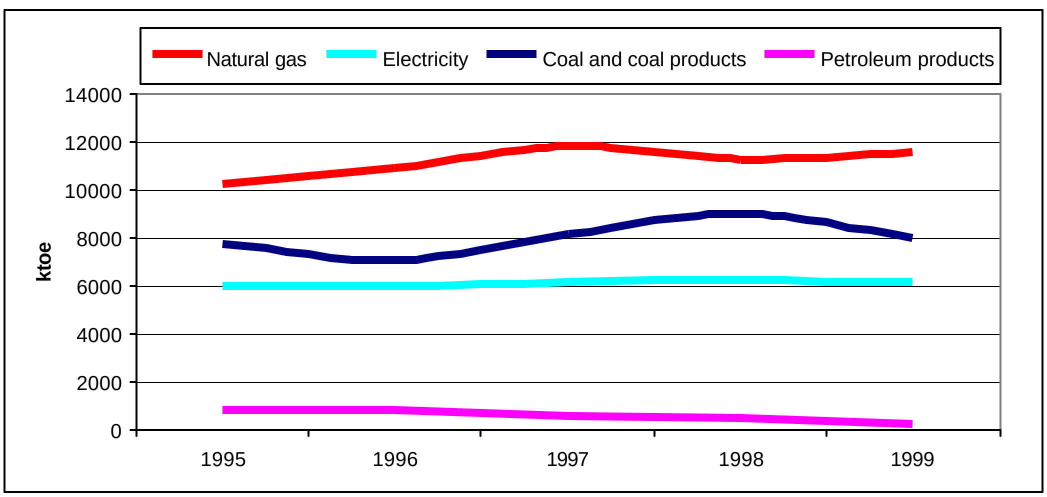
Figure 4 shows fuel use in the iron and steel industry in the US during the period 1995-99. Consumption of coal and coal products fluctuated during the period, remaining higher than that of electricity and petroleum products. Petroleum products experienced a decline at an annual rate of 21.5 percent, while electricity experienced an average growth rate of 0.4 percent. Natural gas was the main fuel used by this industry, and had an annual growth rate of 2.5 percent over the period.

Table 8 Gas use in industries in the US (1980-1999), ktoe

	1980	1985	1990	1995	1999
Total Final Consumption	337,411	296,639	302,989	326,358	318,344
Total Industry Sector	151,529	124,344	123,771	126,264	120,091
Iron and Steel	0	0	0	10,215	11,552
Chemical and Petrochemical	0	0	0	56,406	45,762
(Memo: Feedstock Use In Petrochem. Industry)	0	0	0	0	0
Non-Ferrous Metals	0	0	0	6,643	6,464
Non-Metallic Minerals	0	0	0	9,072	9,597
Transport Equipment	0	0	0	3,167	3,488
Machinery	0	0	0	9,310	9,952
Mining and Quarrying	0	0	0	0	0
Food and Tobacco	0	0	0	12,381	14,084
Paper, Pulp and Printing	0	0	0	14,143	13,840
Wood and Wood Products	0	0	0	1,429	1,599
Construction	0	0	0	0	0
Textile and Leather	0	0	0	3,143	3,332
Non-specified Industry	151,529	124,344	123,771	357	422

Source: IEA (OECD) Energy Balance Tables (2001)

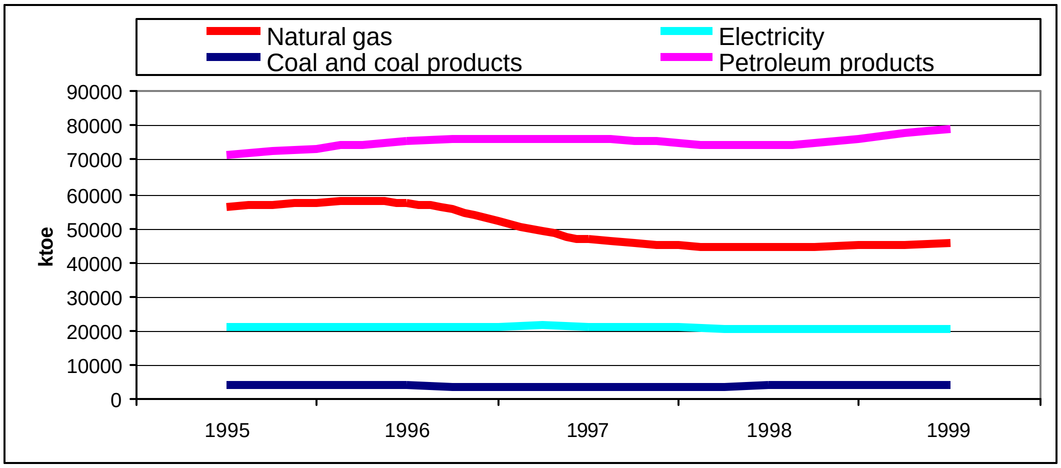
Figure 4 USA's iron and steel industry energy consumption by fuel (1995-1999)



Source: IEA (OECD) Energy Balance Tables (2001)

Figure 5 illustrates fuel use in the chemicals and petrochemicals industry. Petroleum products dominated at an annual growth rate of 2.5 percent over the period 1995-99. Electricity use did not feature as a competitor but possibly as a support base fuel, with a declining annual growth rate of 0.5 percent over the same period. Some of this electricity was internally produced in gas-fired cogeneration systems. Coal and coal products experienced a small growth at an annual rate of 0.8 percent, while natural gas consumption was higher than electricity and coal and coal products but lower than petroleum products, and experienced a decline at an annual rate of 4.1 percent for the 5 years. Due to unavailability of data in the IEA Energy Balance Tables (2001), analysis was done for the last fives years only.

Figure 5 USA's chemical and petrochemical industries energy consumption by fuel (1995-1999)



Source: IEA (OECD) Energy Balance Tables (2001)

NATURAL GAS PRICING IN NORTH AMERICA

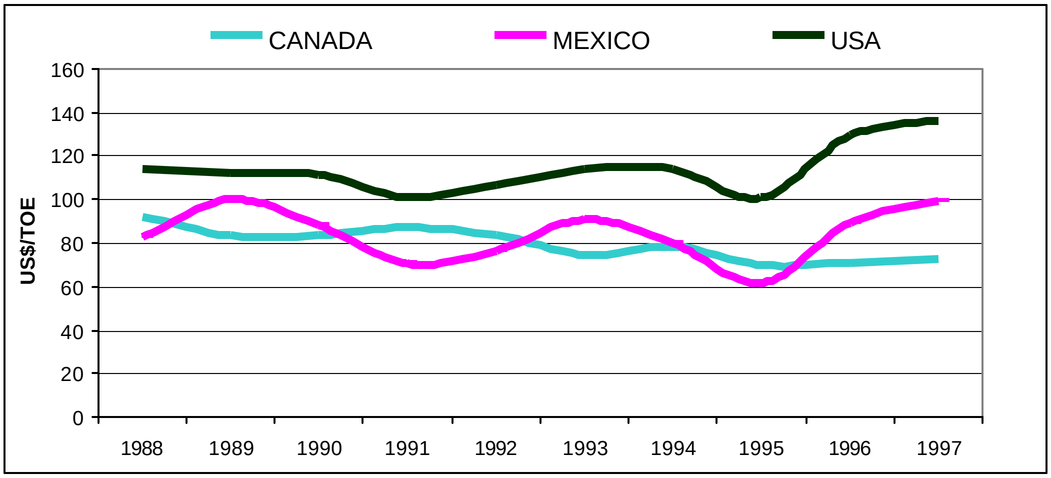
To the end-users in industries, natural gas's price over other fuels such as coal and oil is perhaps the most important parameter that determines its competitiveness. Coal has been a mainstay fuel because of its abundance and stable and relatively cheap supply, whereas oil is becoming less attractive because of supply and price volatility. Natural gas is a newcomer relative to the other two fuels, and its utilisation growth has been more remarkable, with greenhouse gas emissions now a major point in energy development and utilisation. Any additional price paid would be attributed to natural gas being a premium fuel.

Figure 6 illustrates the natural gas price trend in Canada, Mexico and the US over the period 1988 to 1997. It shows that the natural gas price for industry in Canada in general was less than in the other two economies, and was quite stable but with a slight declining trend, with an annual growth rate of minus 2.6 percent. Gas prices in Mexico and the US fluctuated more, with positive growth rates of 2.0 and 2.1 percent, respectively. For these economies the price band has remained at US$60-140/toe.

The following points may contribute to price formulations: economic conditions and competition, weather, regulations, taxes, public utility franchises, quality of product, demand for product, reliability of service, location of product, storage and transport costs, and utilisation patterns. Thus, a stable gas supply over long distances from remote reserves and in seasons of high demand commands premium prices. Furthermore, all other things being equal, the per-unit cost of delivery for large volumes of gas is cheaper than for small volumes.

Natural gas can be costly to transport and distribute. Hence, large-volume consumers tend to be located in areas with the lowest prices – that is where the large industrial consumers are concentrated. Concentrations of consumers encourage delivery systems for higher volumes of gas, put downward pressure on prices, and induce additional competitive suppliers to tailor supplies to customers' needs.

Figure 6 Natural gas prices for industry in North America



Source: IEA Natural Gas Information (2000)

In the United States, there are significant differences in quantities and purposes of gas use between different regions. Residential consumption, primarily for heating, draws large quantities of gas into the Midwest, New York/New Jersey, the West, and the mid-Atlantic regions. Gas consumption for electricity generation dominates in the Southwest, the Southeast, and the West, while industrial use is extensive in the Southwest, the Midwest, and the Southeast regions. These regional usage patterns influence and are in turn influenced by prices and price components in multiple ways.

In North America, deregulation may have eliminated or reduced cross-subsidies in transport rate structures and retail distribution markets. At the same time, due to efficiency gains in commodity gas markets, overall inflation-adjusted prices for all classes of consumers have fallen. Regulatory changes over the past two decades have helped encourage more transparent and cost-effective transport rates. Retail markets are slowly being opened up to competition with the potential to reduce or remove cross-subsidies.[12]

Table 9 shows prices for natural gas, steam coal, high-sulphur fuel oil (HSFO) and light fuel oil (LFO) for Canada, Mexico, and the United States, in US dollars per tonne of oil equivalent. The first impression from the table is that natural gas prices in all three economies are significantly cheaper than for light fuel oil, and in the case of Canada, are also cheaper than high-sulphur fuel oil. Gas prices in Canada and Mexico are significantly lower than the price in the United States as the two economies are gas producers and net exporters. For Canada, the price of natural gas is half that of light fuel oil, and in 2000, with the oil price peaking, the gas price was about one-third. Similar comparisons could be made for Mexico, with the gas price half as expensive as light fuel oil, except that when the oil price peaked in 2000, the natural gas price also increased by more than one-and-a-half times its price in 1999. In the United States, which imported about 18 percent of its gas supply in 2000 from Canada, prices between natural gas, HSFO and LFO are more competitive – coal remains attractive with its price less than half that of gas or LFO, and relatively stable over the six-year period. In general, over the six-year period, natural gas prices increased by 4.3 percent in Canada, 16 percent in Mexico, and 9 percent in the United States.

12 APEC Energy Pricing Practices – Natural Gas End-Use Prices, March 2001

Table 9 Price comparison for competing fuels for industry in North America, US$/toe

		Canada	Mexico	US
1995	Natural gas	77.6	68.4	112.0
	Steam coal	-	-	56.7
	HSFO	117.0	54.4	114.4
	Light fuel oil	170.1	161.1	151.3
1996	Natural gas	79.0	99.2	143.5
	Steam coal	-	-	56.5
	HSFO	132.0	73.5	131.6
	Light fuel oil	208.8	205.7	189.1
1997	Natural gas	80.6	110.4	151.3
	Steam coal	-	-	56.7
	HSFO	125.5	85.1	123.6
	Light fuel oil	194.1	196.8	174.4
1998	Natural gas	78.4	90.4	132.2
	Steam coal	-	-	56.5
	HSFO	86.2	62.6	89.0
	Light fuel oil	137.4	147.9	124.9
1999	Natural gas	88.3	98.1	131.2
	Steam coal	-	-	55.3
	HSFO	119.2	71.4	112.2
	Light fuel oil	169.2	172.1	149.7
2000	Natural gas	99.8	166.7	188.2
	Steam coal	-	-	55.0
	HSFO	190.0	113.0	174.6
	Light fuel oil	283.0	270.6	259.7

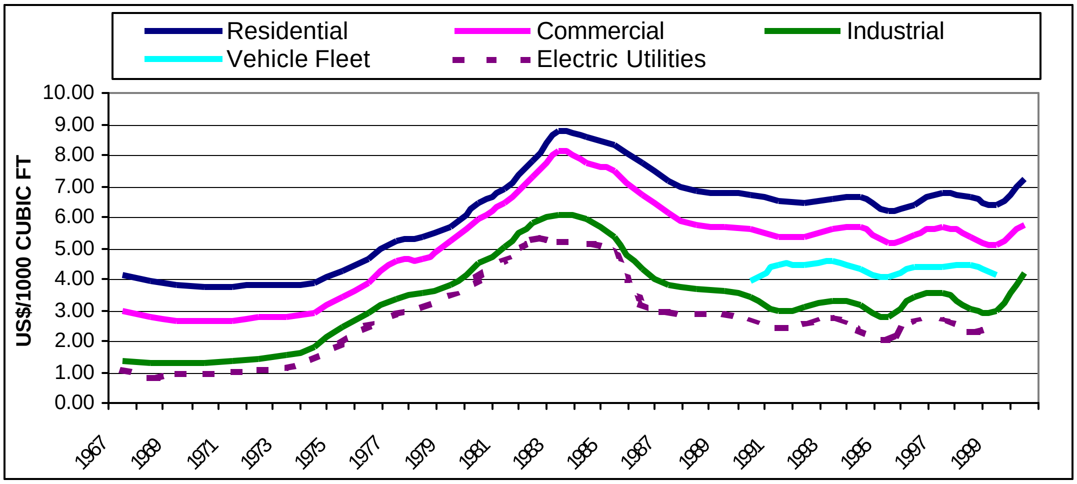
Source: IEA Natural Gas Information (2001)

Figure 7 illustrates price distribution among final consumers from the highest to the lowest natural gas prices in the United States. It is interesting to note that the pattern of price gap between the residential, commercial, and industrial power utility users remains consistent throughout the 34-year period. Residential consumers have been paying the highest prices. The next highest payers are customers in the commercial sector. Vehicle fleets fuelled by natural gas only came onto the scene from 1990, and they enjoyed lower prices than those paid by residential and commercial customers. Industrial users enjoy not only the second-lowest price but also see a significant drop in terms of US$ per cubic foot compared with the other two groups. The power generation sector enjoys the lowest prices, mainly because it purchases gas in large quantities, and through long-term contracts.

Figure 7 also shows the price of gas in US$/1000 cubic feet in each of the respective end use sub-sectors. Annual growth rates are: 1.7 percent for residential consumers, 2.1 percent for commercial customers, 0.6 percent for natural gas vehicle fleet users, 2.6 for the power utility sector and 3.5 percent for overall industrial sector. Between 1979 and 1986, there appears a peaking for all end-use sub-sectors of natural gas, which is probably due to the oil shocks of the mid-1980s.

Industrial gas users have enjoyed the second-lowest prices, next to the power generation sector, since they also consume large quantities, but with flexible gas purchase agreements to cater for possible contingencies in case production capacities are reduced. Industrial consumers in this case includes gas use as fuel and as feedstock in the chemical and petrochemical industries.

Figure 7 Natural gas prices by end-use sectors in the US (1967-2000)



Source: EIA-USDOE Annual Energy Review (2000)

FINDINGS

In North America, the three economies have been able to utilise natural gas across wider sectors. In these economies, natural gas has become a competitive fuel in the industrial sector, against coal and fuel oil, because of its availability in the market. Although natural gas is a relative newcomer, the intensive infrastructure network and the liberalised energy market have accelerated natural gas growth and development, and it is being consumed widely in various sectors of the economy in Canada, Mexico and the United States. Since 1990, gas has also been consumed in the transport sector in natural gas vehicles.

Apart from gas being used as fuel in cogeneration systems for power and heat, it is also being extensively used as feedstock in the chemical and petrochemical industries, and in the fertiliser industry.

Contrary to popular belief that natural gas is more expensive than other fossil fuels (oil and coal) because of it being a premium fuel with environmentally benign characteristics, this chapter has illustrated that gas is indeed cheaper than high-sulphur fuel oil (HSFO) and light fuel oil (LFO), and in certain years, its price is less than half that of LFO in Canada and Mexico. On the whole, the industrial sector has enjoyed a significantly lower gas price than residential and commercial users, but slightly higher than the price paid by power generation industries.

Is natural gas competitive in the industrial sector? This question can be answered by looking at the different end-use sectors within the industrial sector. In the petrochemical industry, the answer is yes. Natural gas has taken over the role of feedstock for olefins. In the US, it has taken over from coke and coal as feedstock for manufacture of ammonia for fertiliser. It is competing against petroleum products as a fuel and as feedstock for chemical and petrochemical products, and as the preferred fuel in the iron and steel industries.

CHAPTER 4

INDUSTRIAL SECTOR NATURAL GAS USE IN SELECTED ECONOMIES

INTRODUCTION

As described in Chapter 2, most developing Asia-Pacific economies utilise gas for the power sector. This is also true for gas exporting economies such as Indonesia, Malaysia and Brunei Darussalam, where a high proportion of their gas supply is utilised as fuel in electricity generation plants. In these economies, despite government efforts and policies to encourage utilisation of natural gas in other sectors, especially in industry, lack of infrastructure, and the inability of the industrial sector to take in high supply volumes, to drive the gas transport business on a commercial scale, has curbed the expansion of a natural gas supply network to include other sectors.

The two elements - lack of infrastructure, as well as lack of industrial users – are a mismatch and each tends to wait for the development of the other. In such cases government policies, bundled with incentives such as low taxes on imported raw materials or export products during the first few years of manufacturing, are important to encourage further utilisation of natural gas.

In developing economies, where natural gas is being consumed in the industrial sector, it is used more as raw material rather than as fuel. In this category of use, natural gas is utilised as feedstock in the manufacture of chemicals and other form of derivative fuels. In some reports, documents, or energy databases, such use of natural gas as feedstock is classified as non-energy use. In others, where energy data recording and collection does not particularly distinguish feedstock input as separate from fuel use, use of natural gas in this conversion process is conveniently grouped with 'consumption'.

The APEC Energy Database groups feedstock as part of energy consumption in industry. The IEA Energy Balance Tables, however, provide a breakdown of natural gas being utilised in various industry groupings, as well as gas being used as feedstock in petrochemical industries. For feedstock use, no further disaggregation is available. For China and Indonesia, for example, the IEA Energy Balance Tables would be unable to provide the data on gas used in the petrochemical and fertiliser industries. Such data had to be sourced directly from the economies, and in most cases the data is unavailable.

As for prices, it is common for price differentials to exist between consumer groups and locations. Prices are usually set and agreed on by negotiation between suppliers and consumers according to such factors as differences in demand and willingness and ability to pay. In a monopoly situation, a monopoly serving different markets and different locations may set the price.

FUEL USE OF NATURAL GAS IN INDUSTRIES

AUSTRALIA

Over the last 25 years natural gas demand has increased by 5.5 percent a year, rising from 1,821 ktoe in 1973-74 to 6,954 ktoe in 1998-99, and its share of energy consumed in the industrial sector has increased from 10 percent in 1973-74 to almost 30 percent in 1998-99. One of the major reasons for this strong growth has been the substitution of gas for petroleum products in stationary applications. Over the same period the share of petroleum use in the industrial sector has declined from 39 to 17 percent. This substitution was due to a number of factors, including the 1970s oil price shocks; the development of a natural gas industry and the continuing extension of the natural gas transmission and distribution network; and the ease of handling natural gas coupled with its environmental benefits.

Table 10 Gas consumption in Australia's industrial sector (1979-1999), ktoe

	Non-Ferrous Metals	Non-Metallic Minerals	Chem. and Petro-chemical	Food and Tobacco	Paper, Pulp and Printing	Iron and Steel	Other	Total
1979	584	912	691	283	313	105	321	3,209
1980	611	1,064	895	352	347	200	380	3,849
1981	643	1,147	927	377	358	304	409	4,165
1982	656	1,118	908	382	372	298	418	4,152
1983	783	1,027	1,147	382	342	259	376	4,316
1984	747	1,016	1,209	413	371	288	384	4,428
1985	1,273	1,122	1,183	429	366	287	405	5,065
1986	1,399	1,179	1,218	456	392	343	424	5,411
1987	1,431	1,220	1,228	490	394	433	495	5,691
1988	1,528	1,255	1,315	511	413	296	491	5,809
1989	1,648	1,283	1,298	520	448	272	507	5,976
1990	1,766	1,234	1,359	524	394	344	502	6,123
1991	2,060	1,090	1,216	510	361	314	491	6,042
1992	2,148	1,088	1,132	544	370	302	476	6,060
1993	2,237	1,095	1,100	551	387	301	479	6,150
1994	2,360	1,140	1,205	580	417	375	495	6,572
1995	2,407	1,166	1,246	613	423	392	530	6,777
1996	2,393	1,093	1,123	591	482	450	520	6,652
1997	2,422	1,103	1,147	590	484	466	540	6,752
1998	2,437	1,101	1,157	608	494	482	639	6,918
1999	2,554	1,115	1,093	594	484	465	697	7,002

Source: IEA (OECD) Energy Balance Tables (2001)

NON-FERROUS METALS

The non-ferrous sector is the largest consumer of natural gas in the Australian industrial sector. The sector is made up of a number of mineral processing industries including smelting and refining of copper, silver, lead and zinc products, the processing of nickel ores and the refining of alumina. Over the last 20 years the use of natural gas has increased over four-fold, from 584 ktoe to 2,554 ktoe, and its share of energy use in the sector has increased from 18.2 percent to 36.5 percent, while that of petroleum products has fallen from 30.3 percent to 18.2 percent.

This large increase in the use of natural gas has been brought about by the substitution of petroleum products, in particular fuel oil, and the rapid increase in the size and importance of the sector. For example, alumina production in Australia has increased by over 300 percent over the last 25 years and it has become the largest alumina producer in the world, currently accounting for nearly 30 percent of world production.

NON-METALLIC MINERALS

This sector comprises mainly clay products such as bricks and tiles together with glass and cement production. The consumption of natural gas in this sector has increased from 912 ktoe to 1,115 ktoe. Again, the major substitution has occurred at the expense of petroleum products. The use of energy in this sector is primarily for high-temperature kilns. Natural gas is ideal for this application, as it is a clean-burning fuel that is easily regulated and does not present the problems associated with storage and handling associated with petroleum products or solid fuels.

FOOD AND TOBACCO/PAPER, PULP AND PRINTING

The major use of process energy in these sectors is for steam production in boilers. The use of natural gas in the food and tobacco sector increased from 283 ktoe in 1979 to 594 ktoe in 1999. Its fuel share remained stabilised around 8.6 percent, while that of petroleum products fell from 8.6 to 3.3 percent over the same period. In the pulp and paper industry, natural gas consumption increased from 313 ktoe in 1979 to 484 ktoe in 1999, at the expense of petroleum products.

IRON AND STEEL

Natural gas consumption in this sector has increased from 105 ktoe in 1979 to 465 ktoe in 1999. Most of this increase was at the expense of petroleum products.

Historically, natural gas (and petroleum products) use in the Australian iron and steel sector has been confined to a relatively minor energy flow into existing blast furnace technology iron and steel plants, principally in post-smelting processes such as rolling mills or plate manufacture. However, in recent years a new iron and steel process known as direct reduced iron (DRI) has established itself in Australia. The DRI process produces iron from iron ore without going through the molten pig iron stage. DRI is obtained when iron ore is processed into partially metalised iron granules using reformed natural gas (for a more detailed explanation of this process see Appendix), though other processes can use coal. It is projected that the DRI process will experience rapid growth in Australia over the next 20 years, with production of DRI increasing to 4.5 million tonnes in 2009-10 and around 7 million tonnes by 2019-20. This rapid increase in production could lead to an increase of natural gas consumption in the order of 2,000 ktoe.

NATURAL GAS PRICING IN THE INDUSTRIAL SECTOR

The Australian natural gas industry has undergone considerable change over the last few years and further change is expected. Although competition among gas suppliers is currently limited, the development of new fields and increased pipeline interconnections will lead to more intense competition. This will lead not only to greater competition among gas suppliers but also against competing fuels such as coal and electricity. Although there is some quantitative information to suggest that gas prices have already fallen, price data is not readily available or excludes important groups of consumers, and it is too early to say how much the anticipated benefits of reform have flowed through to end-users.

INDONESIA

To date, one known industry in Indonesia that has utilised natural gas is the Krakatau Steel plant in West Java. The plant received its gas supply from the PERTAMINA-operated Northwest Java fields as early as in 1978, at first for power generation only. In 1990, the gas started to be utilised both for heat and power, with a capacity of 3.612 MCMD.

In addition to Krakatau Steel plant, several cement plants in West Java are also known to have utilised natural gas for heat generation. By 2000, Krakatau Steel plant utilisation had increased to

17.36 MCMD[13], indicating an average annual increase of 15.5 percent a year. By comparison, in the same year the cement industries consumed 3.422 MCMD, about 20 percent of the single steel plant.

Table 11 provides Indonesia's consumption pattern for natural gas in the iron and steel industry as well as in the cement industries. For the iron and steel industry, gas consumption increased by an annual average of 9.4 percent in 1985-96, during Indonesia's economic boom, but in 1997-99, a period of economic downturn, gas consumption dropped by an annual average of 10.1 percent. For the cement and other industries, the data seemed to be more questionable, showing a high degree of fluctuation.

Table 11 Indonesia's natural gas consumption and growth in the industrial sector

	Iron and Steel Industry		Cement Industries		Other Industries	
	ktoe	% Growth	ktoe	% Growth	ktoe	% Growth
1985	372	-	45	-	1,259	-
1986	380	2.2	46	2.2	1,589	26.2
1987	402	5.8	49	6.5	1,664	4.7
1988	492	22.4	45	-8.2	1,632	-1.9
1989	638	29.7	64	42.2	646	-60.4
1990	829	29.9	90	40.6	256	-60.4
1991	1,077	29.9	128	42.2	101	-60.5
1992	1,051	- 2.4	132	3.1	122	20.8
1993	1,145	8.9	120	-9.1	156	27.9
1994	1,018	-11.1	67	-44.2	205	31.4
1995	988	-2.9	139	107.5	428	108.8
1996	1,004	1.6	122	-12.2	218	-49.1
1997	890	-11.4	112	-8.2	152	-30.3
1998	811	-8.9	37	-67.0	263	73.0
1999	721	-11.1	57	54.1	305	16.0

Source: IEA (Non-OECD) Energy Balance Tables (2001)

JAPAN

Japan is an example of an LNG importing economy that puts its gas imports to varied use: in power generation and in industry, as well as in the commercial and residential sector. A big share of the gas is consumed by the power sector (70.3 percent), with residential/commercial sector use coming second (at 21.4 percent). Industry is the third-biggest consumer of gas at 13.7 percent.

Japanese industry demand for natural gas was 9.45 BCM in 1999. The gas is used as fuel in diverse manufacturing industries, including the food industry, textiles, pulp and paper, ceramics, iron and steel, non-ferrous metals, and machinery production. As observed in Table 12, the chemical and petrochemical industries, machinery production, and the iron and steel industries are the three main gas consumers, taking 57.6 percent of the share of gas use by industry in 1999.

During the 10 years from 1989 to 1999, the volume of natural gas consumption in the industrial sector more than doubled, from 4,159 ktoe to 8,510 ktoe, an average annual increase of

[13] Shahabudin, 2002

almost 7.4 percent. The biggest increase was in the pulp and paper industry with an average annual rise of 18.3 percent, from 119 ktoe in 1989 to 641 ktoe in 1999, and with the food and tobacco industry second with an average annual increase of 9.1 percent, from 440 ktoe in 1989 to 1,048 ktoe in 1999. The increase of gas consumption in the iron and steel industry was 2.6 percent. The annual increase for the non-ferrous and textile industries was 7.7 percent and 8.4 percent, respectively. Gas consumption in the chemical and petrochemical industries increased by an annual average of 6.6 percent, from 880 ktoe in 1989 to 1,674 ktoe in 1999.

Continuing demand for natural gas, including industrial needs, prompted Japan to import more gas. Three Japanese companies, Tokyo Gas, Osaka Gas and Toho Gas, signed a contract in 2000 for the import of gas from Malaysia's new LNG facilities, MLNG Tiga, with deliveries over 20 years starting from 2004. Tokyo Gas, Toho Gas, Osaka Gas and Tohoku Electric in late 2000/early 2001 also signed agreements for gas imports from Australia's North West Shelf LNG project for gas deliveries to start in 2004-05. Japan is planning to deregulate its retail gas sector over the next few years, with the aim of increasing competition and decreasing gas prices, hence promoting more use of gas across its economy.

Table 12 Gas consumption in Japan's industrial sector (1989-1999), ktoe

	Food	Textile	Pulp and Paper	Chem. and Petro-chem.	Iron and Steel	Non-ferrous	Machinery	Other Manufac-turing	Total
1989	440	79	119	880	1,256	156	977	252	4,159
1990	481	88	169	965	1,386	189	1,090	268	4,636
1991	541	101	527	1,038	1,538	209	1,060	363	5,377
1992	595	109	754	1,080	1,614	219	1,046	309	5,726
1993	630	123	796	1,187	1,905	240	1,099	306	6,286
1994	672	125	852	1,215	2,086	245	1,246	306	6,747
1995	697	124	888	1,211	2,030	241	1,320	541	7,052
1996	864	161	576	1,373	2,052	321	1,245	1,153	7,745
1997	920	174	610	1,477	1,985	328	1,432	1,228	8,154
1998	985	170	615	1,522	2,021	319	1,534	1,280	8,446
1999	1,048	177	641	1,674	1,618	328	1,613	1,411	8,510

Source: IEA (OECD) Energy Balance Tables (2001)

*Year indicates Japan's fiscal year. For example, 1989 means the period from April 1989 to March 1990.

MALAYSIA

Malaysia has three main sources of natural gas, from offshore Sarawak, offshore Peninsular Malaysia and offshore Sabah, all three located in the South China Sea. Large gas finds were first made in 1969 off Sarawak, and in 1973 off Peninsular Malaysia. It was not until 1983 that production of LNG began, with the first delivery from Bintulu in Sarawak going to Japan. Currently, most LNG exports originate in the gas fields off Sarawak. Some of this gas is also utilised domestically in Sarawak. Gas from off-shore Sabah started delivery (to Sabah State) in 1984.

The gas off Peninsular Malaysia is piped and distributed throughout the peninsula by a comprehensive network of trunk pipelines called the Peninsular Gas Utilisation (PGU) pipelines, developed and completed in three stages. PGU-1, the first stage of the national pipeline network project, was completed in 1985 to supply gas for electricity generation and industries on the east coast. The Perwaja Steel mill near Chukai, Trengganu, producing 250 kTY (thousand tons per year) of sponge iron and steel, was the first industrial user to utilise natural gas for its manufacturing processes, receiving 0.644 MCMD. By comparison Malaysia's first natural gas-fuelled 900 MW

Paka plant located near the gas-receiving terminal in Kertih was utilising 4.2 MCMD of gas when in full load operation.

In Sabah, the only known industry that utilises gas is an export-oriented hot briquette iron (HBI) plant operating on Labuan Island. The plant consumes 0.56 MCMD, compared with 1.624 MCMD by a methanol plant and 0.224 MCMD by a power generating plant, all located on the same island. All the gas comes from off-shore Sabah.

The latest and biggest single industry to utilise natural gas for manufacturing processes is the Nusantara Steel Mill currently under construction in Kudat, Sabah. The heads of agreement (HOA) for the supply of gas to this plant was signed between PETRONAS and Nusantara Steel Group Sdn Bhd in June 2000 for the supply of up to 5.6 MCMD for 20 years. Under the HOA, PETRONAS will supply gas to the project in two stages beginning from the third quarter of 2003, when the plant is scheduled to come onstream. In the initial stage, from 2003 to 2005, up to 2.8 MCMD will be supplied to the mill. In the second stage, the supply volume will be increased up to 5.6 MCMD from 2006 to 2023.[14]

Of the volume of gas supplied, 70 percent will used as fuel for heating and other manufacturing purposes, while the remaining 30 percent will be utilised as fuel for power generation, with the power to be used exclusively by the steel mill. All gas will be sourced from the fields in offshore Sabah, namely Erb West, Kinarut, and Kebabangan, developed by PETRONAS's production sharing contractors, including its fully owned subsidiary, PETRONAS Carigali Sdn Bhd.

Table 13 shows natural gas consumption in the industrial sector, with values taken from the IEA Energy Balance Tables (2001). This source does not provide a breakdown of natural gas use for Malaysia in various categories of industries, however.

The table shows that natural gas consumption in industry (non-feedstock use) on average accounted for approximately 14.5 percent of total primary gas supply during the period 1985-99. The annual growth rate appears to be fluctuating, with some negative growth for certain years. On the whole, consumption increased significantly from 421 ktoe in 1985 to 2,706 ktoe in 1999, an average annual increase of 14.2 percent.

[14] www.petronas.com.my

Table 13 Gas use as energy in Malaysia's industrial sector (1985-1999), ktoe

	Total Primary Gas Supply	Total Gas Use in Industries	% of Total Use Nationally	Annual Growth Rate (%)
1985	3,570	421	11.8%	-
1986	5,541	893	16.1%	112.1
1987	5,527	951	17.2%	6.5
1988	5,639	897	15.9%	-5.7
1989	6,457	922	14.3%	2.8
1990	6,115	954	15.6%	3.5
1991	9,092	981	10.8%	2.8
1992	9,709	1,201	12.4%	22.4
1993	9,739	1,522	15.6%	26.7
1994	9,855	1,481	15.0%	-2.7
1995	11,108	1,475	13.3%	-0.4
1996	12,562	1,859	14.8%	26.0
1997	15,482	2,205	14.2%	18.6
1998	15,701	2,438	15.5%	10.6
1999	16,583	2,706	16.3%	11.0

Source: IEA (Non-OECD) Energy Balance Tables (2001)

NATURAL GAS AS FEEDSTOCK FOR PETROCHEMICAL PLANTS

Natural gas as produced from the earth contains methane, ethane, butane, propane and other gases in varying compositions, depending on the field, the earth formation or the reservoir from which it is produced. Methane (as much as 85 percent) and ethane (about 10 percent) are the principal constituents of natural gas. There are a number of processing methods to remove unwanted constituents from natural gas.

Methane is a colourless, odourless and highly inflammable gas, and is the simplest of hydrocarbons, one molecule of carbon and four molecules of hydrogen (CH_4). It is lighter than air and occurs in natural gas, as firedamp in coal mines, as a by-product of petroleum refining, and as a product of decomposition of matter in swamps. Methane is valuable as a fuel (cleaner than other hydrocarbons, and of low carbon content), in the production of hydrogen (the main component necessary for fuel cells), hydrogen cyanide, ammonia, acetylene and formaldehyde.

Ethane is also colourless, and is a highly inflammable hydrocarbon gas occurring in natural gas in the form C_2H_6. It is part of the fuel in natural gas. By itself, ethane can be used as a refrigerant.

Propane is a hydrocarbon gas occurring in three molecules of carbon and eight molecules of hydrogen (C_3H_8). Propane occurs in natural gas, in crude oil and in refinery cracking gas. It is used as a fuel, a solvent and a refrigerant. Propane liquefies under pressure and is the major component of liquefied petroleum gas (LPG), together with butane in a lesser percentage. Butane is commonly used too as gas for cigarette lighters.

Pentane is a more saturated hydrocarbon (2.5 times heavier than air), present in two isomers (chemically identical component with different molecular structure), the normal pentane (npentane) and the iso-pentane (i-pentane). Both isomers are used as blowing agents in the manufacture of polystyrene.

Indonesia's natural gas in the East Natuna gas reserves is unique in that it contains about 78 percent non-fuel carbon dioxide. When it was discovered in the early 1970s, the technology for separating the carbon dioxide from the methane gas by cryogenic means was still expensive, such that it was uneconomical to develop the gas fields for natural gas production. Cryogenic technology has since become less expensive and Indonesia would find it economically viable now to produce the gas. Even so, the process of cooling down the gas to a point so that the carbon dioxide (which has a higher condensation temperature than methane) is separated would add to the cost of the natural gas, making East Natuna gas probably Indonesia's most expensive gas compared with natural gas from other fields. If such production were to materialise, Indonesia would also have to find a use for the carbon dioxide by-product. Carbon dioxide is useful in the production of carbonated drinks, and in steel production.

Indonesia's current pipeline gas exports to Singapore from West Natuna, on the other hand, have high methane content and very low ethane and propane contents, the necessary compounds to be produced from natural gas if it is to be used as petrochemical feedstock. Offshore Peninsular Malaysia gas is also rich, with a composition of 79 percent methane, 11 percent ethane, five percent propane, three percent butane and two percent condensates.

Because of its high methane content, natural gas is a natural ingredient for feedstock in the production of methanol. Methanol is primarily used as feedstock for formaldehyde production. The formaldehyde is further used to produce urea-formaldehyde and phenol-formaldehyde resins, which are key bonding agents for plywood and particle board.

Methanol is also an essential component in the production of methyl tertiary butyl ether (MTBE). MTBE, produced from feedstocks of methanol and iso-butylene, is used as a blendstock in gasoline. Worldwide demand for MTBE has increased as the utilisation of oxygenated motor fuels has become more popular. However, its use is being banned in some states of the United States and other economies may follow suit.

AUSTRALIA

This sector comprises numerous activities, including plastics, fertiliser and explosives manufacturing. Natural gas use in this sector increased from 258 ktoe in 1979 to 315 ktoe in 1999. Natural gas is an ideal product in the manufacture of plastics and fertiliser and has substituted for petroleum products such as naphtha, propane and butane.

CHINA

China designated the petrochemical sector as one of the four 'pillar' industries crucial to achieving the goals outlined in its Ninth Five-Year Plan (1996-2000). China has a total of 95 major oil refineries (56 operated by SINOPEC and 39 by CNPC) with a total handling capacity of 4.27 million barrels per day. During this five-year period many petrochemical plants were built in China. In 1997, China's chemical industry production accounted for eight percent of its gross domestic product. Its booming plastics industry relies heavily on chemical intermediates.

Most of the new petrochemical plants to be constructed, however, are oil-based, meaning using feedstock from derivatives of the oil refineries. There are already many petrochemical plants producing ethylene and other petrochemicals scattered all over the territory, most of which are characterised by small production capacity, with some running at a loss. Yet several more modern ethylene plants are to be built. One of the latest plants was announced in February 2001, when joint-venture company BASF-YPC Company Ltd revealed that it had awarded Shaw Group Inc a contract for engineering, procurement and construction of 600,000 tonnes a year of ethylene and related facilities in Nanjing. This 50-50 Sino-foreign chemical facility will cost US$2.6 billion.

Demand for natural gas as feedstock in petrochemical plants will be high. No details of gas-based petrochemical plants, however, are known. China is anticipating that natural gas utilisation will account for eight percent of its energy consumption compared with two percent currently, with much of this as feedstock for petrochemical plants. To meet high gas demand in the future a combination of increased domestic production and gas imports by pipeline from Russia would be necessary. A proposed pipeline from East Siberia is estimated to cost US$6.7 billion, and additional distribution networks infrastructure is estimated to cost US$12 billion. Expansion of China's energy infrastructure will create many opportunities for foreign investment and propel economic growth domestically.[15]

The oil and gas industry restructuring going on in China will ensure higher competition and efficiency, promoting further growth and demand for these commodities, and in particular accelerating the enhancement of the chemical and petrochemical industries in China. In 1998, China reduced the number of central ministries and agencies from 40 to 25, and since March 1998, the new State Administration of Petroleum and Chemical Industries (SAPCI) has been overseeing petrochemical activity. In mid-1998, the industry was divided between China Petrochemical Corporation (SINOPEC) and China National Petroleum Corporation (CNPC), two vertically integrated and commercially driven companies organised roughly on a geographical basis. The purpose of this overhaul was to separate policy-making from business operations. SINOPEC supervises facilities and operations in the eastern and southern parts of China, while CNPC controls facilities and operations in the north and west. The structure of the industry is undergoing further change with the emergence of third-party producers.

INDONESIA

The earliest methanol plant operating in Indonesia was in Bunyu, East Kalimantan, which has a production capacity of 330 kTY. In the 1990s, four more methanol plants were built: PT Prune Offshore in Riau, East Kalimantan (300 kTY), PT Kaltim in Bontang, East Kalimantan (330 kTY), PT Humpuss Mitsubishi in Pare-Pare, South Sulawesi (666 kTY), and PERTAMINA Methanol in Sengkang, South Sulawesi (490 kTY).

There is also an MTBE production facility at the Cilacap refinery, capable of producing 90 MTY of MTBE. Two other MTBE plants were planned in the 1990s but the financial turmoil that hit the economy beginning in mid-1997 has resulted in these plans being shelved.

Two other petrochemical plants are as follows:

1) The Musi refinery, located in South Sumatra, with a production capacity of 15 kTY of purified terephthalic acid (PTA) and 15 kTY of polypropylene;
2) The Cilacap refinery, located in Central Java, which in addition to its refinery product of 120 kTY benzene, also produces 270 kTY of paraxylene.

Total natural gas consumption by these methanol and MTBE plants is shown in Table 14. The table shows a general trend of a high growth rate in gas consumption in the 1990s before the 1997-98 Asian financial crisis (with the exception of 1994).

In a later development, as another diversification of utilising Indonesia's gas resources, Shell is examining the possibility of building a gas-to-liquids (GTL) plant in Indonesia. If the project goes forward, the plant would produce 70,000 bbl/d (barrels per day) of diesel and other middle distillates using the Fischer-Tropsch GTL process (see Appendix).

[15] David Jiang & Richard Warburton, http://ci.mond.org/9908/990809.html

Table 14 Natural gas consumption in petrochemical plants in Indonesia (1990-1999)

Year	Gas Consumption (MCMD)	Growth Rate (%)
1990	12.6	
1991	13.5	7.1
1992	14.3	5.9
1993	15.2	6.3
1994	15.0	-1.3
1995	15.8	5.3
1996	16.9	7.0
1997	17.2	1.8
1998	16.8	-2.3
1999	16.9	0.6

Source: IEA (Non-OECD) Energy Balance Tables (2001)

MALAYSIA

A number of petrochemical plants are in existence in Malaysia, located onshore near the three gas producing areas, off Peninsular Malaysia, and off Sabah and Sarawak. Due to Malaysia's large oil and gas reserves, the petrochemical industry is a logical development strategy pursued by the government to make Malaysia a natural gas and petrochemical hub in Asia, especially in Southeast Asia. Most of the key projects were developed in the Industrial Master Plan (IMP) covering 1986-95. By 1995, Malaysia was producing 550,000 tons of ethylene, 340,000 tons of polyethylene, 200,000 tons of polypropylene and 300,000 tons of MTBE.

These petrochemical plants, whose feedstocks are natural gas or derivatives of natural gas, are:

1) A methanol plant at Labuan Island, Sabah, producing 660 kTY of methanol. The plant (Malaysia's first petrochemical plant) also produces 730 kTY of sponge iron and operates a 79 MW gas power plant. Total gas consumption is 1.96 MCMD;

2) A propylene, polypropylene and MTBE complex near Kuantan on the east coast of Peninsular Malaysia, became operational in 1992. It is owned by PETRONAS (60 percent), Neste Oy (30 percent), and Idemitsu Petrochemical Corporation (10 percent). The feedstock is propane and butane from the natural gas processing plant in Kertih and methanol from the methanol plant in Labuan, Sabah. Its first plant produces 300 kTY of MTBE and 80 kTY of propylene, while the companion plant produces 80 kTY of polypropylene. The MTBE is used domestically to replace lead as a gasoline octane booster. It is also exported. The polypropylene output is supplied to the derivative plastics industry in Peninsular Malaysia;

3) A middle distillate synthesis (MDS) plant at Bintulu, Sarawak, began operations in late 1992. Shell owns 60 percent of the company with the balance shared by Mitsubishi, PETRONAS and the Sarawak state government. The plant, which cost US$600 million, converts natural gas (2.8-4.2 MCMD) to other forms of high-quality fuels: naphtha, kerosene and gasoil;

4) A joint venture plant involving PETRONAS, BP and Idemitsu, in Trengganu, producing 500 kTY of ethylene and 300 kTY of polyethylene. Ethane is supplied by PETRONAS from its natural gas processing plant in Kertih. The plant, which cost US$800 million, began operation in 1995;

5) A joint venture plant involving PNB (National Investment Company) of Malaysia, Chao Group of Chinese Taipei, BTR Lydex of Australia and Himont of USA, with Malaysia's stake at 30 percent. The plant produces: i) 230 kTY of ethylene and 115 kTY of propylene from a flexible naphtha/LPG cracker, ii) 140 kTY of derivatives of high-density polyethylene and linear low-

density polyethylene, iii) 100 kTY of polypropylene. The plant, which cost US$540 million, is located in Pasir Gudang Industrial Complex, in Johore of Peninsular Malaysia. It began operation in 1991;

6) Another plant in Pasir Gudang, built by Idemitsu, producing 180 kTY of styrene monomer and acrylonitrile butadiene styrene (ABS). The project cost US$400 million;

7) Two more plants in Pasir Gudang, backed by BASF and Shell, producing expandable polystyrene (EPS). Each has a capacity output of 70 kTY. They cost about US$40 million each.

Total investment costs for these petrochemical projects (including the ASEAN Bintulu Fertiliser plant) built during Malaysia's Master Industrial Plan (1986-95) was more than US$3 billion. To encourage initial development of this domestic industry the government did not levy taxes on other necessary raw material petrochemicals that were imported.

NATURAL GAS USE AS FEEDSTOCK FOR FERTILISER INDUSTRY

Gas is an important commodity as fuel and feedstock for the production of fertilisers. For China and Indonesia, especially, having the world's biggest and fourth-biggest populations, respectively, it is a top national priority that the agricultural sector is given prime importance to ensure the agricultural yield provides sufficient food and output to feed their people. For this reason, natural gas consumption in China is targeted mainly as feedstock to the fertiliser industry, whereas in Indonesia a substantial 39.2 percent (16.0 out of 40.8 MCMD in 1999) is utilised as feedstock for the fertiliser industry.

The importance of natural gas use in the fertiliser industry is underlined with the two governments providing subsidised prices for natural gas, less than the price paid by end consumers in other sectors.

CHINA

China has 20.3 percent of the world's population, but only eight percent of the world's cultivated land. Therefore, to ensure sufficient food for its people, efficient use of its land is of prime importance. Its economy is still agriculture-based, therefore the fertiliser industry is a strategic one in China.

China has more than 10 large-scale fertiliser plants (with output above 500 kTY), more than 5 medium-scale plants (with output of 30-500 kTY) and more than 100 small-scale plants (with output less than 30 kTY).

Gas prices in China were traditionally set low by the central government. The main reason has been that natural gas is a strategic commodity to China as feedstock for fertiliser plants, to ensure sufficient fertilisers for its huge agriculture sector, and to ensure the well-being of its population. This strategy resulted in the gas production industry in China failing to expand, since investors would not be able to recover their investments due to the low market price.

For the power sector, however, gas is marketed closer to market prices. Currently, 8.7 percent of natural gas is used for power generation. China is planning to build a gas pipeline from the western Xinjiang Uygur Autonomous Region to eastern China (see Chapter 2). This pipeline is expected to stimulate investment in gas exploration and development, lead to the establishment of distribution networks and encourage increased gas use by industry. Foreign companies and investors have been invited by the Chinese government to participate in the investment, construction and management of this pipeline project.

In 1994, domestically produced fertilisers in China used only 24 percent of natural gas. In comparison, 76 percent of anhydrous ammonia in the rest of the world was produced from natural gas. This suggests that China still has a large potential for increased use of natural gas in the fertiliser industry.

IEA Energy Balance Tables (2001) provide some details of natural gas use in the standard categories used by IEA for the industrial sector. Among the gas consumption data are Total Industry Data, and Chemical and Petrochemical, which includes 'Feedstock Use in Petrochemical Industry'. The fertiliser industry is important in China, and as no information is available of other petrochemical plants in which gas may have been used as feedstock, it is assumed that "Petrochemical Plant" in IEA's Energy Balance Tables (2001), mostly if not wholly refers to the fertiliser industry.

Table 15 Natural gas consumption in industries and fertiliser plants in China, ktoe

	Total final consumption	Total industry consumption	Share of total industry to final consumption (3)/(2)	Total chemical and petrochemical industry consumption	Feedstock in fertiliser and petroche-mical industries	Share of fertiliser feedstock to total final consumption (6)/(2)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1985	7,936	6,768	85.3%	3,652	-	
1986	8,328	6,366	76.4%	3,895	-	
1987	8,847	6,685	75.6%	4,088	-	
1988	9,066	6,271	69.2%	4,163	-	
1989	10,267	6,708	65.3%	4,268	-	
1990	11,840	9,530	80.5%	6,314	5,091	43.0%
1991	11,848	9,547	80.6%	6,215	5,063	42.7%
1992	11,529	8,766	76.0%	5,925	4,654	40.4%
1993	12,251	8,987	73.4%	6,354	3,574	29.2%
1994	12,981	9,640	74.3%	7,099	4,734	36.5%
1995	13,084	9,990	76.4%	6,994	3,500	26.8%
1996	13,303	10,278	77.3%	7,072	4,473	33.6%
1997	13,291	9,506	71.5%	7,513	3,250	24.5%
1998	15,202	10,618	69.8%	8,452	4,550	29.9%
1999	15,845	10,817	68.3%	8,785	4,466	28.2%

Source: IEA (Non-OECD) Energy Balance Tables (2001)

Table 15 above shows from 1985 to 1999 the total final natural gas consumption (Column 2), total consumption in the industrial sector (Column 3), gas consumption in the chemical and petrochemical industries (Column 5), and gas consumption as feedstock in fertiliser and petrochemical plants (Column 6). Column 4 provides percentage values of the share of gas consumption in the industrial sector from total final consumption, while Column 7 provides the share of natural gas consumption as feedstock in fertilisers to total final consumption.

The table indicates that overall total final gas consumption increased significantly from 1985 to 1999, with an annual average increment of 5.1 percent, from 7,936 ktoe in 1985 to 15,845 ktoe in 1999. Within this period, however, gas consumption in the industry sector increased by an average annual rate of 3.4 percent, from 6,768 ktoe in 1985 to 10,817 ktoe in 1999. One interesting fact revealed by the table is that while gas consumption in the chemical and petrochemical industries increased by an annual average of 3.7 percent between 1990 and 1999, the quantity of feedstock into such plants (mainly fertiliser plants) actually fell by an average of about 1.4 percent per year during the same period.

INDONESIA

In Indonesia, in the early 1960s when the government established a national goal of achieving self-sufficiency in fertiliser production, natural gas was already onstream for its first Pusri ammonia/urea plant in South Sumatra, established in 1963. Initial gas supply to the Pusri plant was in the range of 0.14-0.28 MCMD.

Demand for gas for the production of fertiliser grew substantially through the 1970s as the Pusri plant was further expanded and an additional fertiliser plant came onstream at Gresik in Java. By 1997, Indonesia had achieved self-sufficiency in the production of nitrogen-based fertilisers, and began to export excess urea production. Further expansions took place in ammonia/urea plants in the 1980s. By the 1990s, there were six ammonia-based fertiliser complexes in operation in Indonesia, which were capable of producing 7,200 kTY (thousand tons per year). The fertiliser plants are: ASEAN Aceh Fertiliser (AAF), PT Iskandar Muda, PT Pusri, PT Kujang, PT Petrokimia Gresik, and PT Kaltim. In 1993, expansion projects were completed, enabling the Pusri complex and the Gresik complex to produce an additional 1,220 kTY and 510 kTY, respectively.

With the exception of the Gresik plant, all of these fertiliser complexes produce ammonia and urea exclusively. PT Petrokimia Gresik produces ammonium sulphate as well. Total production of nitrogen-based fertilisers from natural gas feedstocks in Indonesia is well over 7 million tons per year, with 75 percent of the production consumed domestically and the remaining 25 percent for the export market. With the exception of the ASEAN Aceh Fertiliser plant, all were state-owned. Most of the output from these fertiliser plants is utilised domestically in agriculture, a very important sector to feed Indonesia's 210 million inhabitants. Some surplus urea is sold to the domestic plywood industry and exported.

Table 16 shows gas consumption as feedstock in fertiliser plants since 1987. It shows that gas consumption increased significantly during the industry's expansion years from 1987 to 1991, with an average growth rate per year of 6.2 percent. But in the 1990s the industry appeared to have reached a stable state, with an average increase of 2.8 percent a year until 1999. Starting in mid-1997, when the financial turmoil started to hit the economy badly most expansion plans stalled.

The government has introduced plans to build new plants or revamp existing plants to increase fertiliser production in the 2000s. New technologies are also being planned so that more urea will be produced per volume quantity of gas input. Most of the technologies generally used in existing plants require 868 cubic metres of natural gas to produce one ton of urea. Improved technology could decrease the gas input to 728 cubic metres of gas (a 16 percent saving) for the same urea output.

Table 16 Natural gas consumption in the fertiliser industry in Indonesia (1987-2000)

Year	Gas Consumption (MCMD)	Growth Rate (%)
1987	10.6	-
1988	10.8	1.9
1989	11.7	8.3
1990	12.6	7.7
1991	13.5	7.1
1999	16.9	2.8 (annual average)
2000*	19.6	16.0

Source: IEA (Non-OECD) Energy Balance Tables (2001) for 1987-1999

* 2000 consumption data is obtained from [Shahabudin, 2002]

MALAYSIA

The ASEAN Bintulu Fertiliser plant, completed in 1985, is another joint venture project among some of ASEAN member economies. The project cost US$358 million. Malaysia (PETRONAS) owns 63.5 percent of the company, Indonesia and Thailand each own 13 percent, the Philippines owns 9.5 percent, and Singapore owns 1 percent. In this plant all the natural gas feedstock supply is the responsibility of Malaysia, with the gas coming from offshore Sarawak. It was built to produce 1,000 tons per day of ammonia and 1,500 tons per day of urea. Gas feedstock is 1.12-1.4 MCMD. About 90 percent of the ammonia is used as further feedstock to produce granular urea. An upgrading project was completed in 1991 that increased the production capacity to 1,200 tons per day of ammonia and 1,800 tons per day of urea.

NATURAL GAS PRICING PRACTICES

It is a common practice for price differentials to exist between consumer groups and locations. Prices are usually set and agreed by negotiations between suppliers and consumers according to such factors as differences in demand and willingness and ability to pay. In a monopoly practice a monopoly serving different markets and different locations may set the price.

APERC's publication, *APEC Energy Pricing Practises – Natural Gas End-use Prices*, published in March 2001, deliberates at length on natural gas pricing mechanisms in economies discussed in this chapter.

CHAPTER 5

NATURAL GAS PROJECTIONS AND PROSPECTS IN SELECTED ECONOMIES

INTRODUCTION

This chapter presents independently derived projection figures for gas use in industrial activities based on similar methods to those used in the APEC Energy Demand and Supply Outlook 2002. Unfortunately, results of only two economies are shown in the sub-sector level.

Certain economies may focus the use of their gas more towards direct use as fuel for industrial processes such as the iron and steel industry, while others may concentrate on the use of gas as feedstock in chemical, petrochemical or fertiliser plants. This really depends on each economy's priorities and well-being as outlined in their policies. More applications in industries may also emerge utilising natural gas for cogeneration. Earlier chapters provided information on current gas consumption patterns in most of the gas producing and consuming economies together with future strategies of some of the economies.

Two of the 21 APEC economies, Brunei Darussalam and Papua New Guinea, have no indication of gas use in their industries. Consumption of gas is minimal at present in five economies - the Philippines, Peru, Viet Nam, Singapore, and Hong Kong, China. However, there are strong indications of gas use in their industrial sectors sometime during the projected period. Analysis of selected economies is derived from the APEC Energy Demand and Supply Outlook 2002 project regarding total industrial gas consumption only, and gives only the total industrial sector gas demand projections. For further reading on this subject, please see the APEC Energy Demand and Supply Outlook 2002.

REFERENCE CASE SCENARIO

Table 17 shows projection figures for natural gas consumption in the industrial sector for 12 APEC economies for five-year intervals from 2005 to 2020. There is no further breakdown. The numbers in red refer to natural gas's share of fuel consumption in the industrial sector compared with other fuels such as oil (petroleum products), coal, electricity and renewable energy sources (biomass).

The table illustrates different gas development scenarios for different economies, with gas producing economies portraying higher gas consumption in industries, and the gas importing economies (Japan and Korea) only able to use a small share of natural gas. Economies such as Australia, Canada, Indonesia, Malaysia, Mexico and Russia are gas exporters and therefore have better opportunities to utilise their indigenous resources domestically, with a share of about a quarter to a third of the total end-use consumption in industry.

Economies such as Australia and Canada, which have already achieved a 'balanced' fuel diversification in industry, currently demonstrate a very small increase of natural gas consumption and share for industrial use over the next two decades. Australia, for example, shows only a small increase of gas consumption growth in industry, amounting to annual average growth of 2.8 percent, with the percentage of gas's share increasing very slightly at 0.9 percent. One reason for this almost stable natural gas consumption and share in the industrial sector is because electricity, petroleum and coal will still play a dominant role in Australia's energy sources in the industrial sector over the next two decades. Canada's gas consumption shows 5.2 percent growth, and gas has a share of three percent over the 21-year period. During this period Canada's dependence on electricity (which mainly comes from hydropower) and oil will not change much from the current situation. Coal's share in final energy consumption will remain constant throughout the two decades at 1.9 percent in 1999 to 1.8 percent in 2020.

Indonesia and Malaysia, Southeast Asia's biggest gas producer and exporter, show a parallel trend where more gas will be utilised in the industrial sector. After being successful at utilising gas for the power sector (especially Malaysia), the energy strategies of these economies are geared to utilising more indigenous gas resources for their industries so that not only is more gas consumed, but its share also increases. However, projections show that despite Indonesia's gas consumption showing healthy annual average growth of 2.9 percent, gas's fuel share is only 0.3 percent. For Malaysia, gas shows an average growth rate of 4.1 percent over the two decades, but its share declines to 0.9 percent.

Mexico is a different example of a gas exporting economy. Mexico also reached a 'balanced' share of natural gas use in industry of 31.2 percent in 1999. Despite gas consumption growing at an annual average rate of 4.4 percent, natural gas's share will actually increase by an annual average of 0.5 percent.

Table 17 Industrial sector natural gas demand projection until 2020 – consumption (process, fuel and non energy) (ktoe) and gas share in percent

	1999	Share	2005	Share	2010	Share	2015	Share	2020	Share
AUS	7,003	29.0%	8,300	28.8%	9,600	30.2%	10,900	31.1%	12,500	32.6%
CDA	22,580	32.4%	27,400	33.5%	30,700	33.6%	34,100	33.7%	38,100	34.0%
PRC	10,817	3.1%	14,800	3.4%	18,500	3.8%	24,200	4.5%	31,700	5.2%
INA	6,571	33.3%	9,100	33.5%	10,700	33.5%	12,500	33.5%	14,500	33.3%
JPN	8,510	6.3%	9,500	6.6%	10,500	7.1%	11,800	7.8%	13,300	8.5%
ROK	2,042	3.7%	3,000	4.4%	4,100	5.2%	5,300	5.9%	6,800	6.8%
MAS	2,706	24.0%	3,200	20.1%	4,000	19.8%	5,100	19.9%	6,300	19.7%
MEX	11,244	33.6%	15,600	34.9%	18,800	34.3%	22,800	34.2%	27,800	34.9%
NZ	2,431	43.4%	2,600	43.3%	700	16.3%	800	17.0%	1,000	20.0%
RUS	37,631	27.2%	50,600	24.5%	60,300	23.9%	70,200	23.3%	79,100	22.7%
THA	1,018	4.9%	1,400	6.2%	1,900	6.6%	2,500	6.5%	3,300	6.7%
USA	120,091	33.6%	127,600	32.2%	134,300	31.9%	139,000	31.5%	144,000	31.2%

Source: IEA Energy Balance Tables (2001) for 1999 and APERC for projection

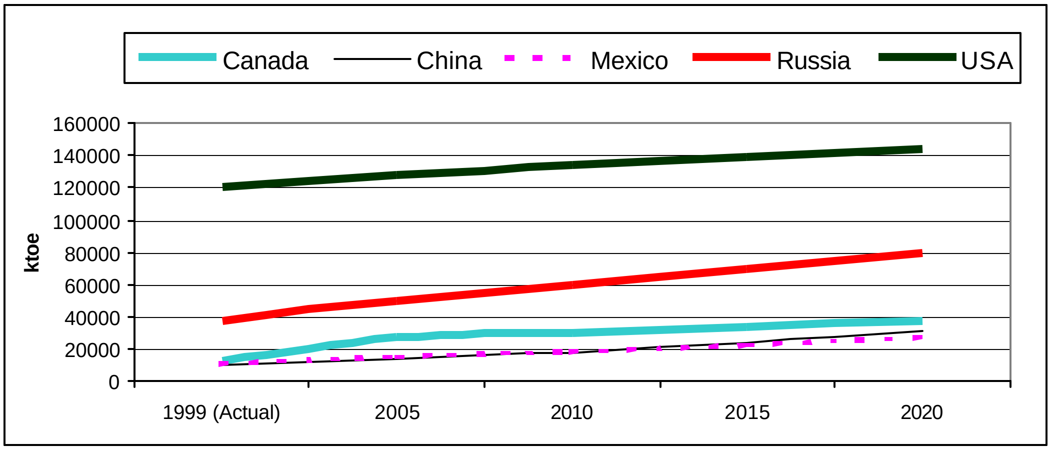
Russia displays a rather different scenario over the 21-year period. While gas consumption in industry will grow by an average 3.5 percent, its share will decrease by an average of 0.5 percent a year. Electricity's share in Russia will increase from 13.1 percent in 1999 to 15.7 percent in 2020.

China and Thailand are similar in that they both have indigenous gas resources, and are currently pursuing self-sufficiency strategies in natural gas production. Gas consumption in their industrial sectors is relatively low, currently 3.1 percent for China and 4.9 percent for Thailand. The share of natural gas consumption in the industrial sector for China will grow 2.5 percent, and for Thailand it will increase by 1.4 percent. Gas consumption in Japan and Korea is projected to increase at an annual average rate of 2.1 percent and 5.9 percent, respectively. New Zealand's natural gas use is expected to decline between 2005 and 2010 due to the depletion of the Maui field and the subsequent closure of a methanol plant that uses natural gas as feedstock. New Zealand's industrial natural gas demand is projected to decline by 4.4 percent per year.

In 1999, New Zealand had the highest share of natural gas utilisation in the industrial sector among APEC economies at 43.4 percent.

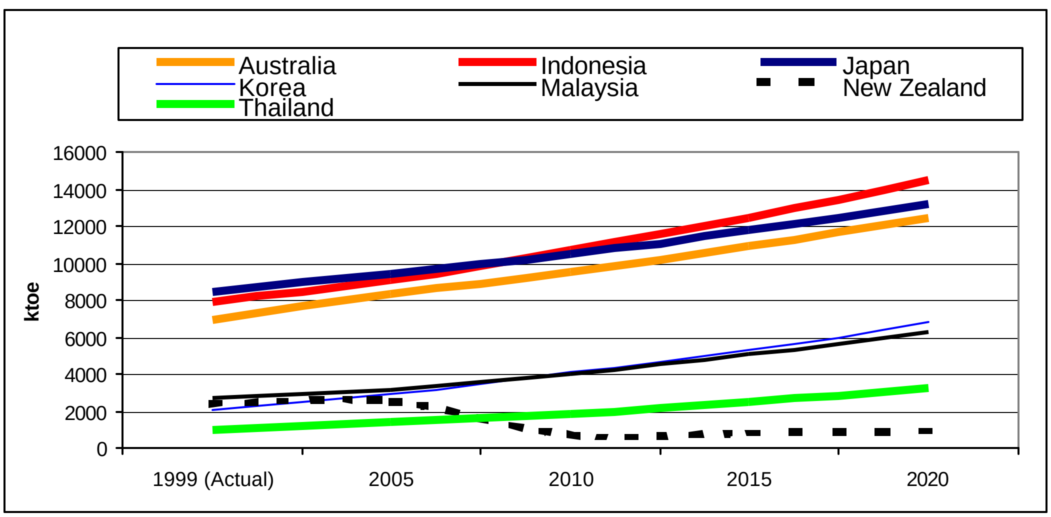
The United States is the largest consumer of natural gas in the industrial sector, using three times more than the next large gas consuming economy, Russia. US gas use is poised to grow over the next two decades by an annual average of 0.9 percent, with gas imports coming from traditional suppliers Canada and Mexico. The share of gas used as fuel, however, will fall by an annual average of 0.2 percent.

Figure 8 Industrial natural gas use projection to 2020 for Canada, China, Russia, US and Mexico (ktoe)



Source: IEA Energy Balance Tables (2001) for 1999 and APERC for projection

Figure 9 Industrial natural gas use projection to 2020 for Australia, Indonesia, Japan, Korea, Malaysia, New Zealand and Thailand (ktoe)



Source: IEA Energy Balance Tables (2001) for 1999 and APERC for projection

INDUSTRY FOCUS – EXAMPLES IN INDONESIA AND KOREA

This section investigates further two economies, Indonesia and Korea, noting the particular area of their industries where most natural gas will be consumed. This is done by studying the history of natural gas consumption patterns in the industries using IEA Energy Balance Tables (2001), doing regression on them, and with the econometric equations found, the consumption is projected over the 21-year period. To illustrate the effects, the trend curves of these particular applications are plotted against the curve for total gas demand. This trend conforms and links this project with the APEC Energy Demand and Supply Outlook 2002 project due to the use of similar methodology in the projections.

INDONESIA

Figure 10 shows the potential growth for natural gas consumption in the chemical and petrochemical industry as well as the iron and steel industry in Indonesia. For the historical trend, IEA (2001) Energy Balance Tables data specifies natural gas consumption in the chemical and petrochemical industries fully as feedstock – hence none of the gas is recorded as being used as fuel or for other processes. Within feedstock use, again the data does not specify the share of the feedstock being used for fertiliser plants, which are a strategic industry for Indonesia, nor is the figure specified for feedstock into chemical and petrochemical plants. According to another source, in 2000, of 23.5 MCMD of gas consumed as feedstock, 84 percent went to fertiliser plants, 10.4 percent was used for chemical and petrochemical plants, and six percent in the manufacture of LPG.[16] Hence, the figures given by the IEA are assumed to mostly represent feedstock for fertiliser plants.

Natural gas consumption in the industrial sector is projected to increase by 2.9 percent per annum, from 8,170 ktoe in 2000 to approximately 14,500 ktoe in 2020. The projected annual growth rates by industrial sub-sector are 3.9 percent for chemicals and petrochemicals, 2.3 percent for iron and steel, 4.4 percent for non-metallic minerals, and 7.6 percent for 'other', as shown in Figure 10.

An interesting trend shown by Figure 10 is that while feedstock took the highest share in Indonesia's total gas consumption in the industrial sector in 1999 (at 84 percent), the share will decline over the projection period. It is projected that by 2005 the share of feedstock will still be high at 80 percent, but it will decline gradually to 78 percent by 2010, 76 percent by 2015 and 74 percent by 2020. The decline in feedstock in the chemical and petrochemical industry is balanced by a significant rise by the 'other' sector.

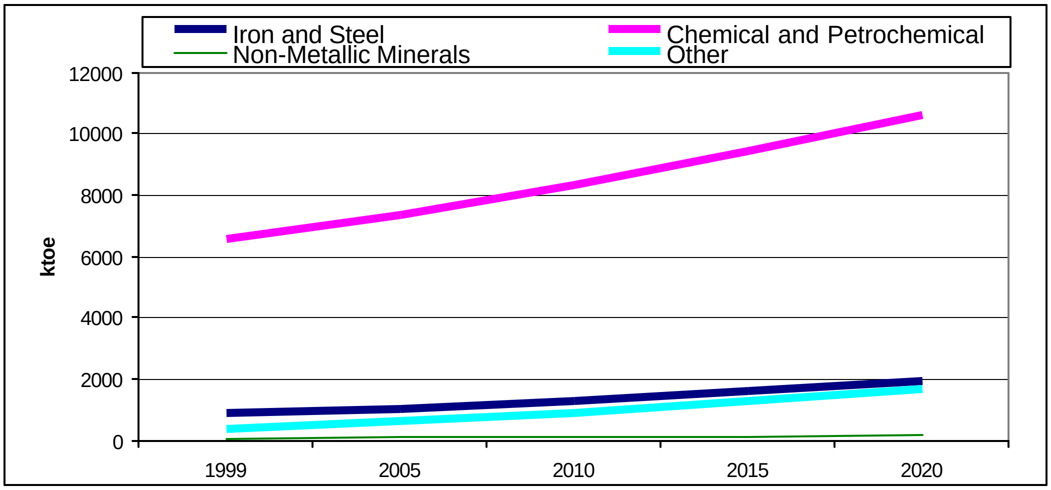
For the iron and steel industry, gas consumption will increase over the projection period, and its share will increase slightly. Currently, the share of natural gas consumption is 11 percent, and this will increase to 13 percent by 2020. Gas consumption will increase to 1,936 ktoe by 2020 from the current 867 ktoe.

'Other' in Figure 10 indicates especially the cement industry, which like the iron and steel industry is one where gas has been used widely.

Annual growth rates for natural gas consumption in Indonesia used in this projection are 3.0 percent, about the same level as the APEC Energy Supply and Demand Outlook 2002 growth rate of 2.9 percent per annum.

[16] Shahabudin (2002), Energy Situation in Asia – Producing Countries Perspective

Figure 10 Projection of Indonesia's sectoral gas consumption in industries (ktoe)



Source: IEA Energy Balance Tables (2001) for 1999 and APERC for projection

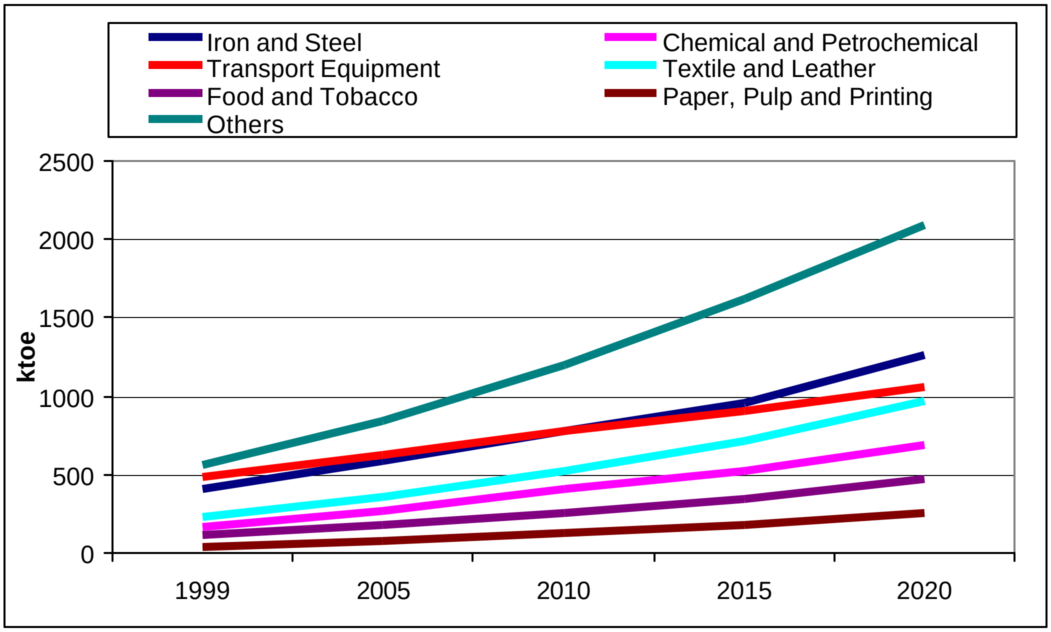
KOREA

Natural gas use in the industrial sector in Korea is mainly for iron and steel, transport equipment and others. For the chemical and petrochemical industry, natural gas consumption is only 8.5 percent. In 1999, the share of natural gas use in the transport equipment industry was about 24 percent, while in the iron and steel industry it was around 20 percent. Natural gas is also used in various industries including textiles, food and tobacco, and paper, pulp and printing. The share of natural gas use was 11.6 percent, 5.6 percent and 2.4 percent, respectively, in these industries.

Figure 11 shows natural gas consumption for the years up to 2020 in the industrial sector for Korea. It is projected that the iron and steel industry's consumption of natural gas will be 1,263 ktoe in 2020. The transport equipment industry will have the second-largest share in 2020, with consumption of 1,050 ktoe. On the other hand, the chemical and petrochemical industry is projected to consume 689 ktoe. Textiles, food and tobacco, paper and printing are predicted to increase to 968, 476 and 253 ktoe in 2020 from 238, 116 and 49 ktoe in 1999, respectively. It is also projected that other industry sectors will increase natural gas demand from 568 ktoe in 1999 to 2,090 ktoe in 2020.

The annual growth rate for Korea used in this projection is 5.9 percent, which is the same level as the one in the APEC Energy Supply and Demand Outlook 2002.

Figure 11 Projection of Korea's sectoral gas consumption in industries (ktoe)



Source: IEA Energy Balance Tables for 1999 and APERC for projection

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

GENERAL CONCLUSIONS

Most developed APEC economies that have their own indigenous natural gas resources have been able to utilise natural gas widely across sectors, namely the power sector, the industrial sector, and the residential and commercial sector. Because of wide availability of natural gas in Canada, Mexico and the United States, North America has become a region in APEC where natural gas is most versatile in its use. There is a similar situation in Australia.

In the industrial sector in North America and Australia, natural gas is widely used as fuel as well as for direct processes in industry. The largest consumption in 1999 for Canada, Mexico and the US was in the chemical and petrochemical sub-sector, while for Australia it was the non-ferrous metal industry. The share of gas consumed by the chemical and petrochemical industry out of the total gas consumption by the industrial sector was 35 percent for Canada, 49.5 percent for Mexico and 38.1 percent for the US. For Australia the non-ferrous metal industry accounted for 36.5 percent.

In developing and gas producing economies especially Malaysia, Indonesia and Thailand, most of the natural gas is utilised for the power sector, with a share of 61.1 percent, 21 percent and 73.5 percent, respectively. The amount used in the residential/commercial and transport sectors is small and almost insignificant.

NORTHEAST ASIA

Japan and Korea are big natural gas importing economies. In 1999, Japan used most of its imported gas for the power sector taking 70.3 percent, with the residential/commercial sector taking up 21.4 percent, and the industrial sector taking up the least, at 13.7 percent. In the industrial sector in Japan, the three sub-sectors with the highest consumption of gas are the chemical and petrochemical industry followed by the iron and steel industry and the machinery industry.

The residential/commercial sector accounted for 47.4 percent of gas consumption in Korea in 1999, followed by the power sector taking 36.8 percent and the industrial sector 13.5 percent. In the industrial sector, most of the gas was consumed by the transport equipment industry, which had a share of 24.1 percent and the iron and steel industry with 19.9 percent.

In China, the fertiliser industry is regarded as strategic, with the aim of ensuring there is enough fertiliser production for its agricultural needs. China is also expanding its chemical and petrochemical industry, which is currently mostly oil-based. These two industries will become major natural gas consumers when more natural gas is available in the market in future through the development of gas pipelines.

SOUTHEAST ASIA

Gas used in the industrial sector is mainly concentrated in chemical and petrochemical plants including fertiliser plants, although some gas is being used in industries such as iron and steel (for Indonesia and Malaysia), and cement (for Indonesia).

In Indonesia in 1999 the fertiliser industry, one of its strategic industries, accounted for more than 19.7 percent of total gas use. The industry will continue to dominate the use of natural gas in the future. Malaysia, building to become a hub of chemical and petrochemical manufacturing in Southeast Asia, will continue to utilise more natural gas in this industry in the future. When the existing Peninsular Gas Utilisation (PGU) network extends its distribution lines further, other industries will be able to have access to natural gas.

NORTH AMERICA

In the industrial sector in North America, natural gas is widely used as fuel as well as for direct processes in industries. In Canada, the pulp, paper and printing industry consumes the largest amount of natural gas in the industrial sector; in the United States it is the food and tobacco industry and in Mexico the iron and steel industry.

North America has a very good system of pipeline networks for gas transmission, and sectoral consumption of natural gas has reached a mature level. APERC projects that natural gas consumption in the USA will grow at an annual average rate of 0.9 percent per annum until 2020, while for Canada the figure is 5.2 percent and for Mexico 5.4 percent.

Also, natural gas in the US industrial sector is competing very well with other fuels, as discussed in Chapter 3 and shown in Figures 1, 4 and 5. In the petrochemical industry, natural gas has taken over the role of feedstock for olefins. It has taken over from coke and coal as feedstock for the manufacture of ammonia for fertiliser. It is competing against petroleum products as fuel and as feedstock for chemical and petrochemical products, and is utilised well as fuel in the iron and steel industry.

LATIN AMERICA

In Latin America, Chile shows a diversified use of its natural gas. Table 5 shows that its industrial sector had a share of 7.1 percent of total gas consumption in 1999. The residential/commercial sector had 4.7 percent and the power sector 23.6 percent. 'Other uses' accounted for 64.5 percent. The amount of natural gas consumed in these sectors is expected to increase significantly. The same is expected for Peru, where the Camisea field will start operations in 2004.

OCEANIA

In Oceania, Australia has a diversified use of natural gas in its industries as fuel as well as for direct processing. The largest use is for the non-ferrous metal industry. New Zealand is similar but is on a downward trend due to depletion of the Maui field and closing of a methanol plant.

POLICY IMPLICATIONS

Summarised below are some barriers to overcome in order to materialise the benefits of trans-border gas pipelines to enhance natural gas trade for economies that need to diversify their consumption, especially in the industrial sector.

1) Geopolitical issues need to be resolved by all parties

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

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

This is an important aspect for any pipeline management to ensure the security and reliability of the gas delivered. When a pipeline has to pass through one or more economies, transit rights and transit fees have to be clearly settled to avoid future conflicts that could threaten the flow of energy. No international agreements, such as the European Energy Charter, exist as yet in the Asia-Pacific region so negotiations should be considered under which gas transit can be codified.

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

With energy infrastructure investments driven by the private sector, a transparent tariff system for production, transmission and distribution is needed to assist investors to estimate risks and find investment partners. All parties involved in infrastructure projects, especially pipeline projects for gas transmission, need to have a clear understanding of the benefits to encourage full support.

RECOMMENDATIONS

Further utilisation of natural gas in the industrial sector will cut down pollution and greenhouse gas emissions. Lack of an infrastructure network has been the main reason why in developing economies where indigenous gas is available, it has not been widely utilised in the industrial sector. Governments could encourage further utilisation of natural gas in the industrial sector through institutionalising policies and strategies that will enable natural gas to be more accessible in the market.

In economies where natural gas trunk lines are already in place, governments could provide initiatives in terms of improving the investment climate to attract foreign and local investors in developing further distribution pipelines. As distribution pipelines would not be built without earlier commitments of industrial consumers, efforts should be made by gas suppliers to attract potential industrial customers into making such commitments.

Despite natural gas being a premium fuel, its price (per million BTU) need not always be higher than oil. North America provides a good example that the price of natural gas can be lower than that of oil in industrial use. Further liberalisation of the energy market initiated by governments will let fuels compete openly and hence establish free market prices.

As the United States market shows, natural gas prices can differ from sector to sector, with the price generally highest in the residential sector, followed by the commercial sector, transport, industrial and power. Governments, by minimising their intervention, could give encouragement for prices to be mutually determined between suppliers and customers.

Chemical and petrochemical industries with natural gas as feedstock are important to economies such as Indonesia and Malaysia, as well as Russia, China, Japan and Korea. The incorporation of similar standards and specifications in petrochemical products for specific regions (such as ASEAN or Northeast Asia) could widen the market and enhance the potential of this industry.

Respective governments could play a decisive role in facilitating the development of natural gas infrastructure and related markets by creating business environments that are more stable, transparent, predictable and competitive.

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APPENDIX

GAS CONSUMING PROCESSES AND TECHNOLOGIES

GAS CONSUMING PROCESSES

The purpose of this appendix is to highlight a number of commonly used gas-consuming technologies, elaborating the competitiveness and benefits of its use as fuel in such technologies as compared with other conventional fuels such as oil or coal. While the environmental benefits of using natural gas are universally known, the most important driver determining its use is cost compared to other fuels, the total of which includes transport by pipelines.

The following technologies are seen to have the largest potential for penetration in the industrial sector or for providing an alternative to existing fossil fuel use:

- Cogeneration, although not a new concept, has the potential to provide significant energy savings as well as environmental benefits. A more detailed analysis of these benefits is provided in the companion document by APERC, *Alternative Development Scenarios for Electricity and Transport to 2020 for the APEC Region.*
- Direct Reduced Iron/Hot Briquette Iron (DRI/HBI), which is a relatively new technology, is seen to have the potential for large-scale production against the backdrop of a significant increase in the use of Electric Arc Furnaces (EAF) for steel production;
- Gas to Liquids (GTL), although an 'old' technology, has recently received greater attention as the economics of the technology improve, stricter fuel standards are introduced and concerns about energy security and fuel diversification intensify.

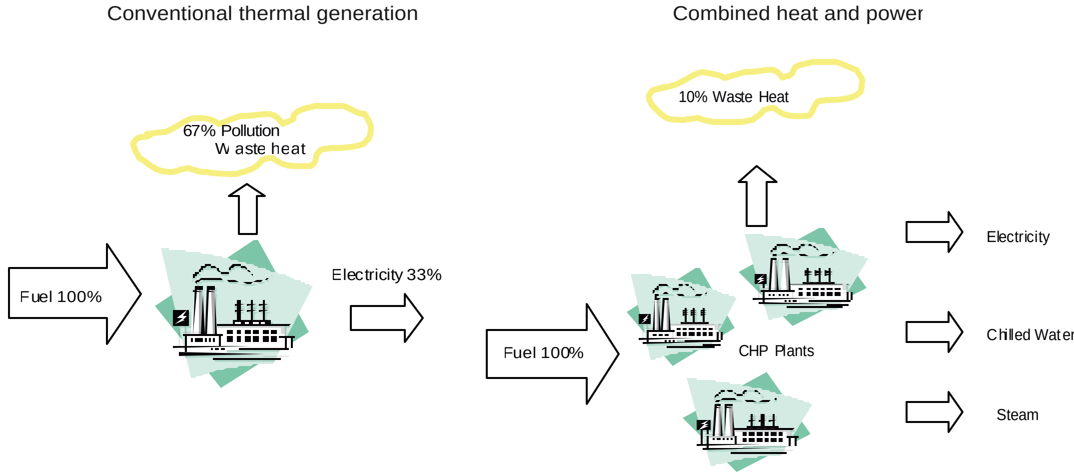
COGENERATION (COMBINED HEAT AND POWER)

Cogeneration in industries, in this context, specifically refers to use of natural gas as fuel to fire cogeneration systems, with the electricity generated solely used by the particular industry and the heat produced utilised in the industrial process. In North America such cogeneration is also termed as non-utility generation (NUG). An on-site cogeneration facility is most appropriate in an industrial plant that requires both electricity and steam for its industrial processes. By combining the production of heat and electricity in one process, the plant can achieve greater efficiency than by separately buying power from an electric utility and producing heat from natural gas. Existing cogeneration facilities operate in industries, but they are fast penetrating residential, commercial and institutional buildings.

Cogeneration, also known as Combined Heat and Power (CHP) systems, as mentioned above, simultaneously generates electricity and useful thermal energy from a single, integrated system. The thermal energy recovered in a CHP system is used for heating or cooling in industry or buildings. The heat capture increases the total efficiency of these integrated systems compared with traditional generation of electric power. Cogeneration has a much higher rate of energy utilisation and energy efficiency than the conventional production of heat and power separately.

CHP is widely used in the chemical, petroleum refining, and paper industries. In recent years, smaller CHP systems have made inroads in the food, pharmaceutical, and light manufacturing industries. In the near future, when distributed electricity generation becomes a more acceptable norm, encouraging own-use power generation with plant efficiency higher than the efficiency of purchased electricity (which could be achieved by employing the latest cogeneration equipment in the market, and an omission of long distance transmission losses), cogeneration could be an attractive alternative for industries which need both electric power and heat.

Figure A1 Conventional thermal generation and combined heat and power (CHP)



Source: Tina Kaarsberg and R. Neal Elliot; Combined Heat and Power: Saving Energy and the Environment

Cogeneration can have a wide range of technologies and can be adapted to many segments of the economy and their particular requirements. Because it sequentially generates electricity and heat from the same fuel source, rather than from separate applications, energy efficiency can be up to 80 percent, resulting in a reduction of greenhouse gas emissions. As the output of both electricity and steam cogeneration units are best sited close to a host, otherwise known as embedded or own-use generation, this also reduces losses arising from transmission.

There are three main commercialised cogeneration technologies: gas turbines, reciprocating engines and steam turbines. Each has specific advantages and disadvantages, and the selection of technology will be dependent on the requirements of the application.

The most common use of these technologies is in a so-called ‘topping’ cycle, in which electricity is generated first and the waste heat is used for industrial or commercial applications. Facilities that generate electricity may produce it for their own use, and then sell excess production to a utility. Topping cycle cogeneration is predominately used in the pulp and paper, food processing and textile industries and in commercial applications such as hospitals and hotels. There is also a ‘bottom’ cycle which produces process steam first and utilises the waste heat for electricity generation through a recovery boiler and a turbine generator. Typical industries for which the bottom cycle is suitable are those that require high-temperature heat in furnaces, kilns or ovens, and reject the heat at significantly high temperatures. Such industries include cement, steel, ceramics and petrochemicals.

GAS TURBINES

Gas turbines generally use natural gas as fuel but can operate on a number of other gaseous and liquid fuels, the most common being distillate. There are traditionally two types of turbines, the industrial gas turbine and the aero-derivative gas turbine.

The *industrial gas turbine*, or heavy frame gas turbine, is a heavy duty unit designed for continuous operation. Although it is not as energy-efficient as the aero-derivative gas turbine it maintains a high level of performance over a long period of time with little maintenance. Maintenance can also be carried out on site and at low cost. The industrial gas turbine also has the advantage of a lower investment cost ($/kW) than the aero-derivative gas turbine and is designed to operate on lower-quality fuels.

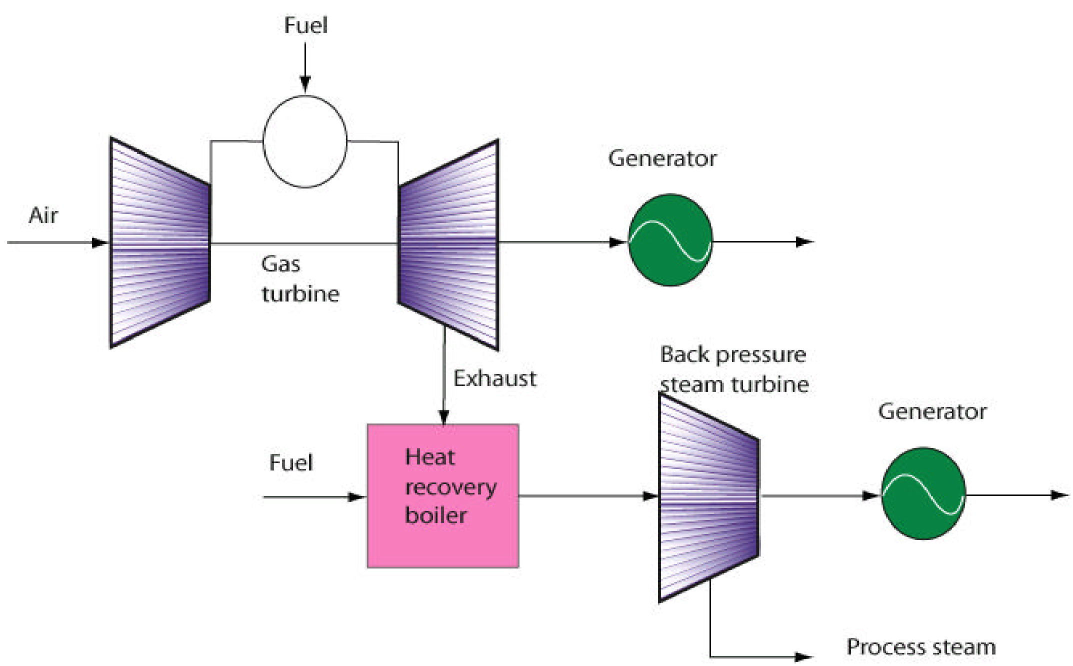
The *aero-derivative gas turbine* is based on the aircraft propulsion engine. It has the advantage of being lighter than the industrial gas turbine, and has lower fuel consumption and a high level of reliability. However, due to its complexity it requires skilled service personnel and may need to be taken off-site for maintenance. The investment cost may be higher than for an industrial gas turbine, and it requires high-quality fuel. Efficiency may eventually decline.

Hot exhaust gases from the turbine are used in the heat recovery boiler to produce hot water or steam. In some applications the hot exhaust gases may be used directly for such applications as preheating or drying, or by passing the gases through a heat exchanger to produce hot water or steam for process needs.

The main advantages of gas turbines are: high power-to-heat ratios, which fit many industry applications, low capital costs, low operating and maintenance costs, short lead times, and no cooling water requirements. One of the limitations of the gas turbine cycle is that it produces electrical energy and thermal energy in a fixed relationship. Where there are wide fluctuations in the amount of energy required, a combined cycle setup is preferable. The thermal energy from the gas-turbine cycle is recovered in a heat-recovery steam generator (HRSG), and this generates high-pressure steam that is expanded through a steam turbine to drive a generator.

As electric and thermal energies are produced independently and can be controlled over wide ranges, combined cycle technology is favoured in many medium-sized cogeneration applications. The heat recovery steam generator is one of the major components of the gas turbine cogeneration system. HRSGs are designed to produce process steam by recovering a large share of the energy contained in the exhaust stream. The exhaust gas is cooled in the HRSG to extract useful heat.

Figure A2 Combined cycle gas turbine schematic



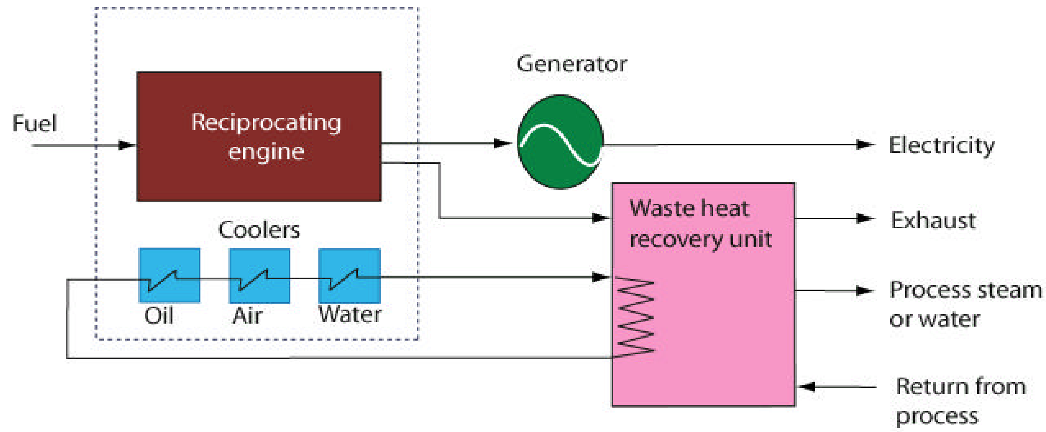
Source: Department of Industry, Science and Resources - *Profiting from Cogeneration*, Commonwealth Government, Canberra

RECIPROCATING ENGINE COGENERATION

There are three main types of reciprocating engines used in this configuration: industrial gas engines, automotive derived gas engines and diesel engines. Historically, diesel has been the fuel of choice. More recently, due to ease of handling and lower, cleaner emissions, natural gas has become the desired fuel input. There are three sources for heat recovery: exhaust gas provides high temperature, and the engine jacket water cooling system and the lube oil energy provide low temperature. Due to the lower levels of available heat this configuration is more suitable for commercial buildings or institutions such as hospitals that have modest electrical loads, relative to industry, and use moderate amounts of hot water.

The reciprocating engine also provides a reliable source of power and heat with very low maintenance costs.

Figure A3 Reciprocating engine cogeneration schematic



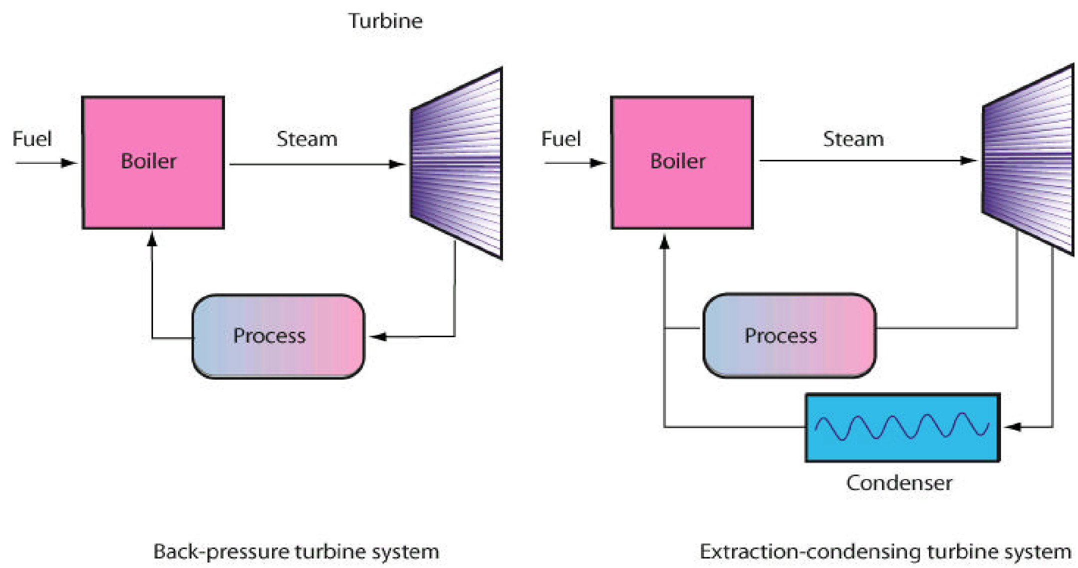
Source: Department of Industry, Science and Resources - *Profiting from Cogeneration*, Commonwealth Government, Canberra

STEAM TURBINE COGENERATION

A steam turbine does not directly convert a fuel source to electric energy but requires a source of high-pressure steam delivered by either a boiler or a heat recovery steam generator. There are two types of steam turbines most widely used in industry, the extraction-condensing and the back-pressure. The choice between these two types depends mainly on the quantities of power and heat, quality of heat, and economic factors.

A back-pressure steam turbine consists of a boiler, turbine, heat exchanger and pump. In the steam turbine, the incoming high-pressure steam is expanded to a lower pressure level, converting the thermal energy of high-pressure steam to kinetic energy and then to mechanical power. Thermal energy of the turbine exhaust steam is then transferred to another fluid in a heat exchanger, providing heat to the processes. The back-pressure steam turbine has a higher heat-to-power ratio and higher overall thermal efficiency. With an efficient boiler, the overall thermal efficiency of the back-pressure system could be as much as 90 percent. However, extraction condensing cogeneration systems have higher electricity generation efficiencies.

Figure A4 Steam turbine cogeneration schematic



Source: Department of Industry, Science and Resources - Profiting from Cogeneration, Commonwealth Government, Canberra

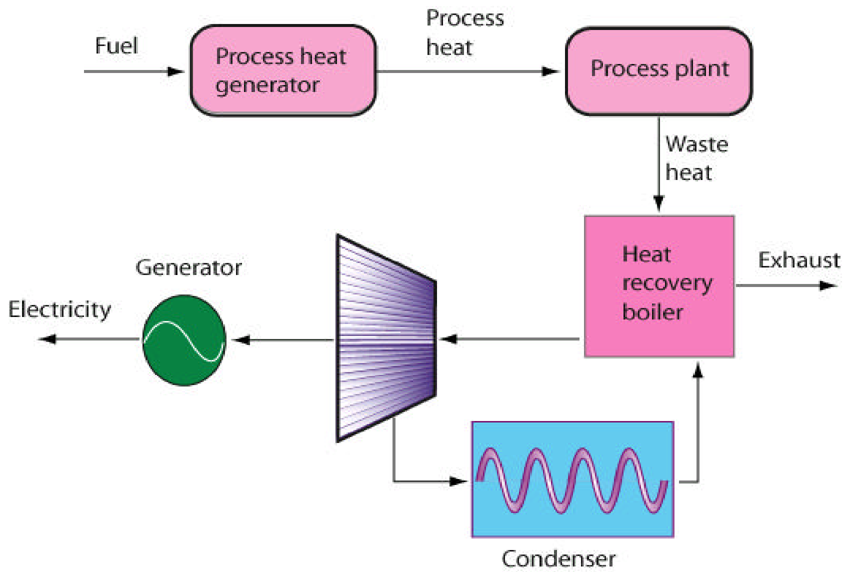
Steam Turbine – Topping Cycle

In this configuration steam is taken from the steam turbine to generate electricity while low-pressure steam is made available for the process requirement. The main advantage of this configuration is that it can operate on a wide range of fuels. A topping cycle plant will always use some additional fuel, beyond what is necessary for the manufacturing process, and hence has a higher operating cost associated with the electricity production.

Steam Turbine – Bottoming Cycle

In this cycle energy is consumed in the process first, and the waste heat is then recovered and converted to electricity. In most cases the waste heat is converted to steam that drives a steam turbine generator. The use of bottom cycle plants is most common in industries such as chemicals, glass and steel, where very high temperature furnaces are used. Because energy is used first for the manufacturing process, no extra fuel is required for electricity generation.

Figure A5 Steam turbine – bottoming cycle schematic



Source: Department of Industry, Science and Resources - *Profiting from Cogeneration*, Commonwealth Government, Canberra

Table A1 Possible CHP sources

FEATURE	Gas Turbine	Combined Cycle	Reciprocating Engine	Steam Turbine
Suitable applications	Where high pressure steam required	Where wide fluctuations in the amount of energy required	Where high pressure steam not required	Where low -cost solid fuel available
Suitable size for application	3MWe upwards	Medium to large	Up to about 3MWe	Low MWe upwards
Electrical efficiency	Moderate to high	High	High for medium size	Moderate
Initial cost	Moderate	High	Low because of low pressure	High
Maintenance and operating costs	Moderate	Moderate	High	High
Fuel choice	Natural gas, can operate on other gaseous or liquid fuels	Natural gas	Natural gas, diesel	Wide range of fuels, ideally suited to biomass
Advantages	Heat recovery steam generator can have supplementary firing	High efficiency	Good operational characteristics w ith small sets	Adaptable to most fuel types

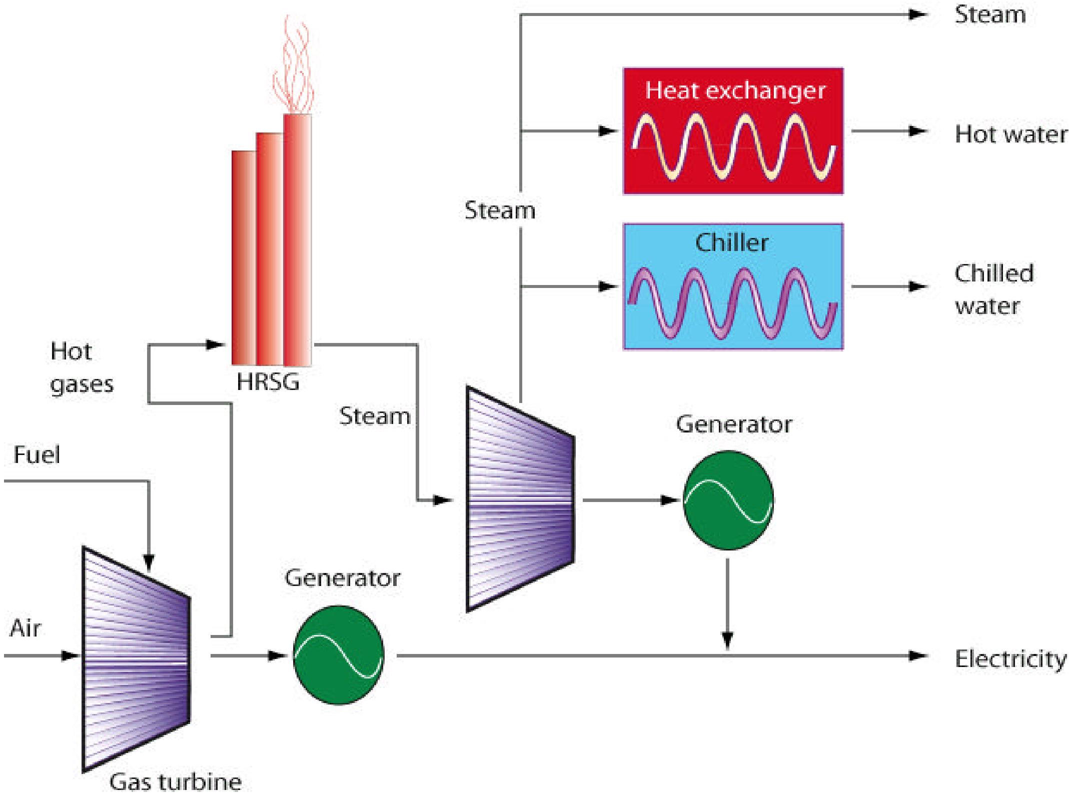
FEATURE	Gas Turbine	Combined Cycle	Reciprocating Engine	Steam Turbine
Disadvantages	Not suitable below about 3MWe	Expensive to manufacture and maintain	Majority of heat expended in the form of low temperature energy	Low power-to-heat ratio and poor match between process steam and electrical requirements

Source: Department of Industry, Science and Resources - *Profiting from Cogeneration*, Commonwealth Government, Canberra

TRIGENERATION AND VAPOUR ABSORPTION COOLING

A new concept that has important implications for the Asian region is trigeneration. In this process three different forms of energy can be produced from the primary energy input - electricity, heat and cooling. This combination is important in tropical areas where there is demand for air-conditioning in buildings and process cooling in industry. A typical trigeneration facility consists of a cogeneration plant as well as a vapour absorption chiller that converts waste heat recovered from the cogeneration plant to produce cooling.

Figure A6 Trigeneration system schematic



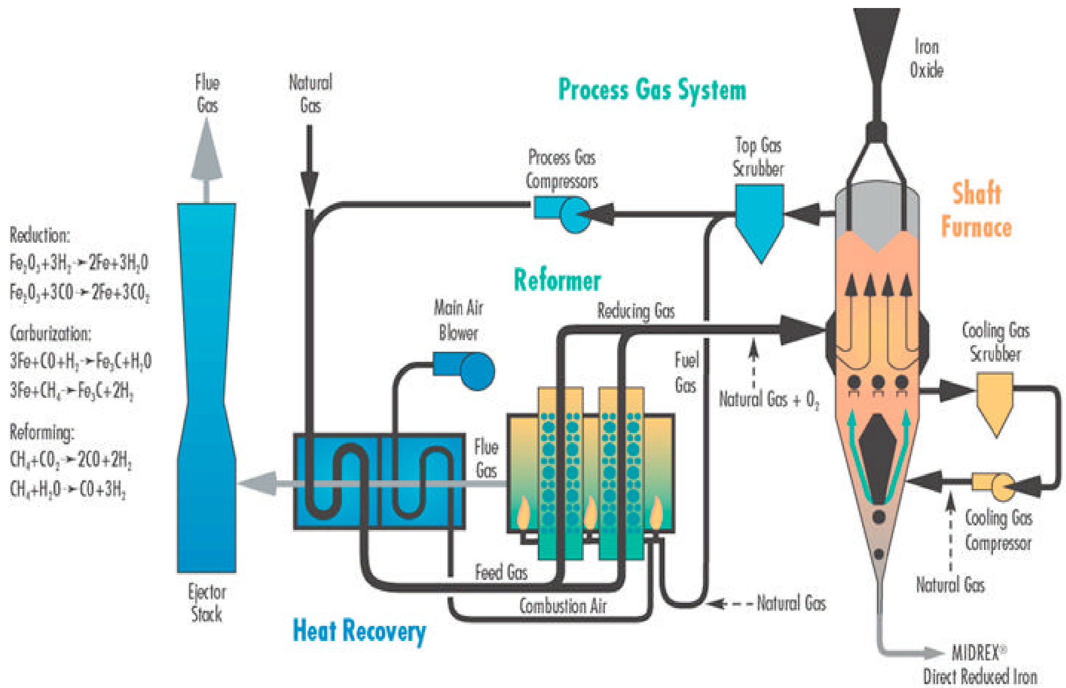
Source: Department of Industry, Science and Resources - *Profiting from Cogeneration*, Commonwealth Government, Canberra

DIRECT REDUCTION/HOT BRIQUETTING

Direct reduction refers to the reduction of iron ore without melting. Impurities in the iron ore remain in the iron product, but most are removed during steelmaking. Hot briquetted iron (HBI) is produced by hot compacting of the direct reduced iron (DRI). DRI is used either as a scrap substitute or to control the level of residuals in the electric arc furnace (EAF) steelmaking process. EAF operators attempt to minimise slag generation as it consumes additional energy, refractory material and electrodes. Very high-grade iron ore is, therefore, essential for the DRI process.

Midrex and HYL processes are the two leading technologies, both using shaft-furnaces and gaseous reductants. In the Midrex process, pellets or lump ore are introduced through a proportioning hopper at the top of the shaft furnace. As the ore descends through the furnace it is heated and the oxygen is removed from the iron (reduced) by counter-flowing gases that have high H_2 and CO contents. These gases react with the Fe_2O_3 in the iron ore and convert it to metallic iron, leaving out H_2O and CO_2. To maximise the efficiency of reforming, offgas from the shaft furnace is recycled and blended with fresh natural gas. This gas is fed to the reformer, a refractory lined furnace, containing alloy tubes filled with catalyst. The gas is heated and reformed as it passes through the tubes. The newly reformed gas, containing 90-92 percent H_2 and CO, is then fed directly to the shaft furnace as reducing gas.

Figure A7 A typical Midrex process



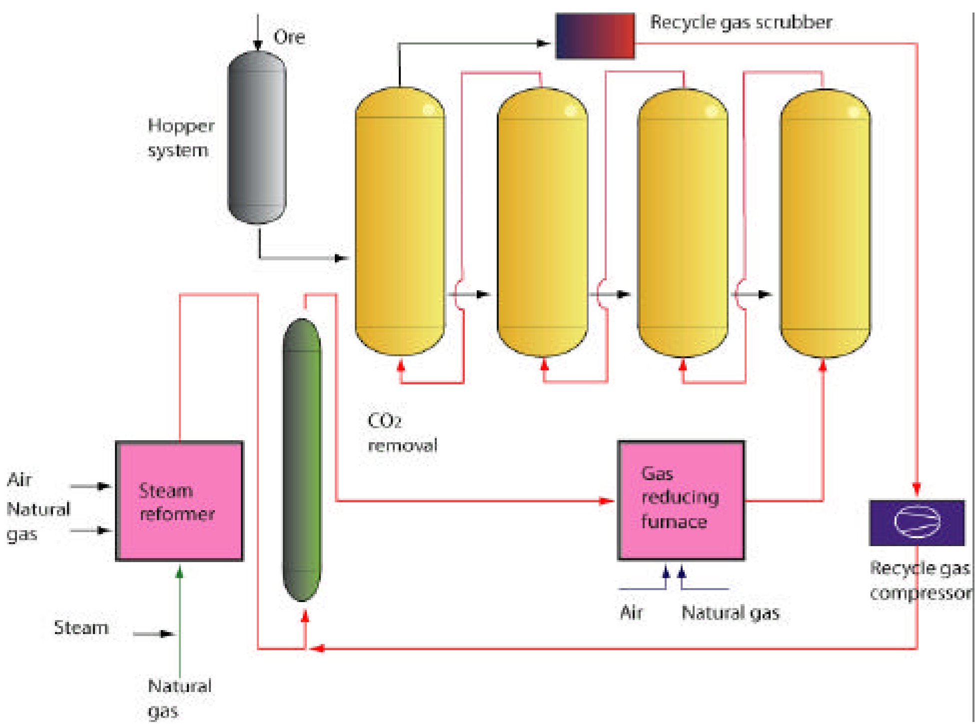
Source: Department of Industry, Science and Resources - *Profiting from Cogeneration*, Commonwealth Government, Canberra

In the HYL process, pellets and/or lump ores are reduced in a shaft furnace reactor. An automated system of valves allows the pressurisation and depressurisation of inlet bins for iron ore charging. The iron ore bed is reduced in the upper part of the reactor by the counter-current flow of hot reducing gases rich in hydrogen and carbon monoxide. In the lower portion of the reactor, a cooling gas circuit lowers the temperature of the reduced iron while increasing its carbon level.

The process used by BHP's HBI plant at Port Hedland in Australia is the natural gas-based FINMET process. In the FINMET process, dried iron fines with a size of 12 mm or less which have been charged through a lock hopper system are reduced in a series of fluidised bed reactors. The ore is preheated in the first reducing reactor by the gas coming from the previous reactor of the series. After a time the partially reduced ore is transferred to the next reactor. The ore is progressively reduced and heated in each subsequent reactor until the desired degree of materialisation is achieved. The highly metallised product is discharged from the final reactor and hot-briquetted to HBI. Any excess fines resulting from screening of the HBI are recycled to the briquetting process.

The required reducing gas (H_2 and CO) is generated from the catalytic conversion of a mix of natural gas and steam in a reformer. Excess CO_2 is removed from the gas stream and the gas composition is adjusted according to the process requirements. The reduction gas is then heated to approximately 830 °C and enters the reactors in the opposite direction to the ore route. The ore fines are efficiently reduced in counter-flow. The degree of metallisation is typically between 91 and 92 percent. The gas is then cleaned and cooled before being recycled to the process.

Figure A8 A typical Finmet process



Source: Sasol-Chevron

GAS CONVERSION TECHNOLOGIES

GAS TO LIQUIDS (GTL)

The term 'Gas to Liquids' refers to the process whereby natural gas is converted into liquid fuels, such as middle distillates (such as diesel and jet fuel), methanol, dimethyl ether (DME) or speciality feedstocks and waxes.

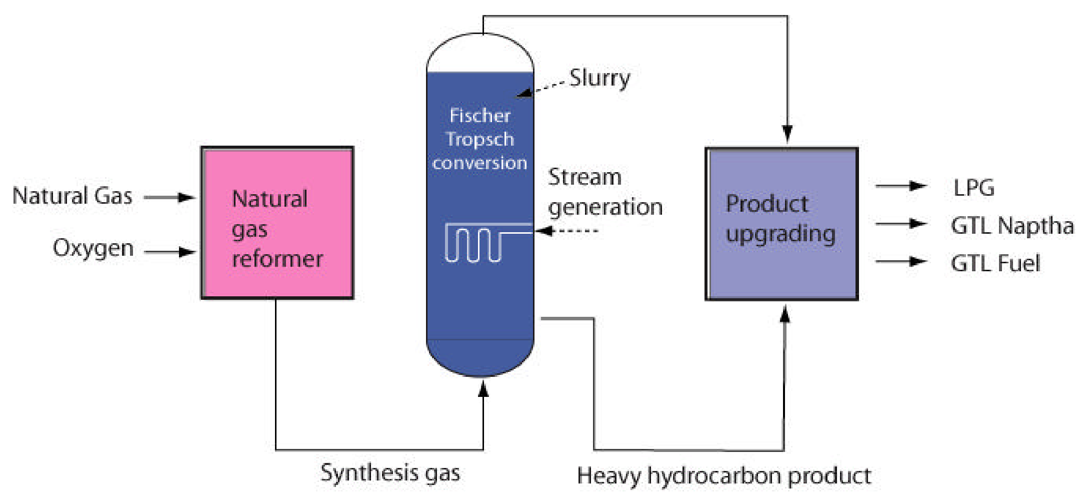
GTL technology offers the potential to provide an alternative to existing oil-based supply while at the same time being more environmentally friendly. It also provides a technology that can monetise remote gas resources and/or eliminate the need to flare gas where it is produced in association with oil as no infrastructure or market exists for its disposal.

It has long been difficult to ensure the economics of GTL. Despite the unfavourable economics, the first practical GTL technology was introduced in South Africa in the 1970s. Thereafter, many other oil and gas companies and petrochemical companies have focused attention on GTL technology. Leaders in this technology have been Shell, Mobil and Exxon (now ExxonMobil), and Sasol, a South African company that deals in coal mining, crude oil refining and petroleum production. Exxon started R&D activities on synthetic fuel in the 1950s and has been demonstrating a 200 barrels/day (Bbl/d) GTL pilot project since 1993. Sasol has operated a coal-based commercial plant adopting a Fischer-Tropsch reaction since the 1950s and a 100,000 barrels/day demonstration plant since 1993. Shell has managed a pilot plant operation since 1989 and has a 12,500 Bbl/d commercial plant in Bintulu, Malaysia.

GTL products require the incorporation of hydrocracking and hydroisomerisation to produce final products. Preferable and practical products of GTL processes are naphtha and diesel fuel. GTL-based diesel fuel has the advantage of environmental and performance benefits compared with diesel derived from oil refinery processes. In general, especially with upgrading of technologies, the GTL process has the advantage of modification and adjustment on a project-to-project basis to produce premium products for each client.[17]

The flow chart below provides a representation of the process employed by Sasol Chevron in a plant being evaluated for the Asia-Pacific region.

Figure A9 Possible GTL process for a plant being evaluated in the Asia-Pacific region



Source: Sasol-Chevron

[17] Soga Takuya (1998)

The GTL process involves four steps:

1) Natural gas purification;
2) Synthesis gas production;
3) Fischer-Tropsch synthesis; and
4) Product upgrade.

The first step involves the removal of impurities that may poison catalysts, and at the same time oxygen is extracted from the air. The 'clean' natural gas and the oxygen stream together with steam are converted into synthesis gas (a mixture of carbon monoxide and hydrogen) by either the process of partial oxidation (POX), or steam reforming, or a combination of these processes called auto-thermal reforming (ATR). The Fischer-Tropsch synthesis process then converts synthesis gas into a broad-range hydrocarbon stream. The reaction involves the conversion of hydrogen and carbon monoxide into long-chain paraffins, light olefins, high molecular weight waxes and water. The final step involves upgrading the hydrocarbon stream into the desired products such as naphtha, diesel, kerosene, lubes and waxes.

GTL PRODUCTS

Ammonia/Urea

The syngas produced in the second step of the GTL process can be used to produce ammonia. The ammonia produced can then be used to produce urea, a white powdery substance, which can be used as a solid or liquid fertiliser or in the manufacture of plastics.

Methanol

Methanol is produced in a three-stage process: syngas production; conversion of syngas to crude methanol; and purification.

Methanol has many uses. In the transport sector it is used to produce methyl tertiary butyl ether (MTBE), a gasoline octane enhancer, although this product is being phased out in some economies, including the US. It can also be used in the production of dimethyl ether (DME), whose major use is for aerosol propellant but which more recently has been considered as a substitute for LPG or diesel. Other uses of methanol include formaldehyde, used in the production of such things as foam and adhesives, and acetic acid, which is used in the manufacture of PET plastic, polyester fibres and water-based paints.

Fischer-Tropsch Products

This process is able to produce a number of products ranging from high-quality specialist lubes and waxes to products such as diesel, kerosene and naphtha. More recently the emphasis has been on the production of liquid transport fuels, in particular diesel. The advantage of GTL fuels is that they contain virtually no sulphur or aromatics, resulting in lower emission levels of hydrocarbon, carbon monoxide, nitrogen oxide and particulates, compared with conventional fuels. GTL fuels also have a higher cetane value, giving them a performance advantage. No major conversions or new infrastructure such as fuel handling systems or fuel tanks are required with the GTL fuels.

GAS-FIRED REFRIGERATION

Vapour compression and absorption technologies are the most often used to provide gas-powered refrigeration to industry. Both technologies use the effect in which the evaporation of a liquid (the refrigerant) requires heat that is taken from the source to be refrigerated. Compression and absorption cycles are two different ways to restore the expanded refrigerant vapour at low pressure into its liquid form at high pressure in a closed loop. The absorption cycle requires thermal power, while the compression cycle requires only mechanical power. The thermal power can be obtained from the combustion of gas leads, and absorption technology is the most suitable to use gas; however, mechanical power is obtained from gas through a thermodynamic cycle in gas engines and gas turbines, thus allowing the compression cycle to be gas-powered.

The refrigerant comes into the evaporator and expands to a pressure at which the evaporation temperature is lower than the required refrigeration temperature. Heat flows from the refrigerated source to the evaporating refrigerant that becomes vapour. Low-pressure vapour is then compressed to a higher pressure so that condensing liquid may be formed at temperature levels slightly higher than those of the cooling water or the air in the condenser. Mechanical energy in the compressor shaft and heat at low temperature in the evaporator are the energy inputs into the cycle; heat delivered in the condenser is the only energy output from the cycle. Waste heat from the compressor's prime mover, engine or turbine, can be used in industrial processes that require thermal power. The system could be compared with a generation group where the electric power is entirely consumed in an electric compressor.

Gas refrigeration units, with compression or absorption technologies, can operate independently or linked to cogeneration systems or combined with other refrigeration technologies; to provide lower refrigeration temperatures or to benefit from an engine waste heat; NH_3/H_2O and $LiBr/H_2O$ absorption groups can be combined to extend to very low temperatures. An absorption unit can be powered by the exhaust gases, from a gas turbine. Flue gases leaving the turbine directly heat the generator at high temperatures, so that NH_3/H_2O and $LiBr/H_2O$ double-effect systems can be powered.