Asia-Pacific
Economic Cooperation

Potential for Growth of Natural Gas as a Clean Energy Source in APEC Developing Economies

APEC Energy Working Group
Expert Group on Clean Fossil Energy

July 2006

Written by:

TAYLOR-DEJONGH

In cooperation with:

RESOURCESLAW INTERNATIONAL

Printed by
Taylor-DeJongh, Inc
1101 17th Street, N.W., Suite 1220
Washington, DC 20036, U.S.A.
Tel: (1) 202-775-0899 Fax: (1) 202-775-1668
Email: contacttdj@taylor-dejongh.com
Website: www.taylor-dejongh.com

Produced for
APEC Secretariat
35 Heng Mui Keng Terrace Singapore 119616
Tel: (65) 67756012 Fax: (65) 67756013
Email: info@apec.org
Website: www.apec.org

APEC#206-RE-01.3

Table of Contents

EXECUTIVE SUMMARY

1.1 Introduction

APEC member economies account for over half of the world's natural gas production, consumption, and exports. APEC is also the heart of the global LNG market with half of the world's exports and 70% of imports. Developing APEC economies are expected to contribute largely to the growth in global natural gas demand in the near future. The utilization of natural gas as an energy source is therefore an important component of APEC economies' energy strategies, and APEC's Energy Working Group is already focused on facilitating the emergence of new initiatives for the development and expansion of natural gas use in the region. While APEC's most industrialized economies have a well developed natural gas sector, many of APEC's developing economies can increase their overall usage of natural gas. As a clean and reliable fuel that can be used both for power generation, for industrial purposes, and for retail consumers, natural gas would be beneficial to the sustainable development of these economies.

This report is meant to be a reference tool for policymakers in APEC economies who are considering, or wishing to expand, natural gas as a clean energy fuel to meet their respective economy's growing energy needs. It begins by examining both developed and developing APEC economies in order to determine the role of natural gas in the primary energy mix in each of these respective economies as well as investigate what steps developing economies may be taking to increase their use of natural gas.[1] The next chapters then examine some of the major concerns policymakers have regarding increasing the utilization of gas within their economies. One major concern in the current environment is the significantly higher price of natural gas in certain markets, thus the cost competitiveness of gas versus other fuels is examined in Chapter 4. Many policymakers also have concerns regarding availability and security of supply. One important potential source of supply is liquefied natural gas (LNG), therefore the content of Chapter 5 is a detailed description of the global LNG trade. Chapters 6 and 7 outline some of the major conditions that must be present for the proper development of natural gas markets. Chapter 8 adopts a case study approach and examines some specific ways in which APEC economies have attempted to increase their utilization of natural gas. Finally, Chapter 9 lays out some important policy measures that governments can adopt to expand the role of natural gas as an energy source in their economies. A brief synopsis of each chapter is provided below.

[1] For the purpose of this study, the developed/industrialized APEC economies are those meeting the World Bank standard for "high income" (GNI per capita on a Purchasing Power Parity basis greater than $10,066). These economies include Australia; Brunei Darussalam; Canada; Hong Kong, China; Japan; Korea; New Zealand; Singapore; Chinese Taipei, and the United States. Developing APEC economies include Chile; China; Indonesia; Malaysia; Mexico; Papua New Guinea; Peru; the Philippines; Russia; Thailand; and Viet Nam.

1.2 Natural Gas Development and Utilization in Industrialized APEC Economies

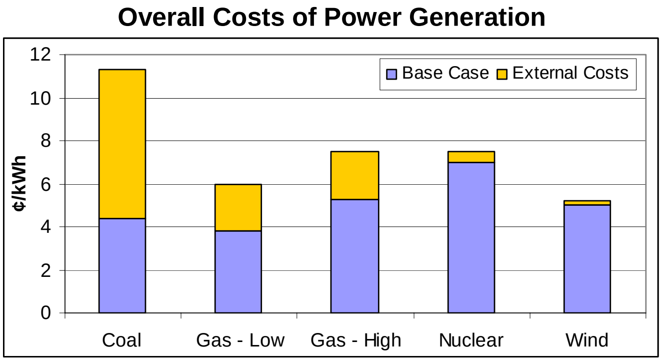
Natural gas is an important energy resource for all APEC economies. Nevertheless, the industrialized APEC economies tend to have a more developed natural gas sector than the developing APEC economies. Despite their widely varied geographic sizes, and available and known gas resources, industrialized APEC economies are all major natural gas users. Natural gas is mostly used for power generation and industrial purposes. Chinese Taipei, Japan and Korea in particular rely heavily on LNG to fuel their power generation facilities. In Canada, the United States and Singapore, industry represents the largest demand for natural gas. Overall, the United States is the largest consumer of natural gas among the APEC economies, and although it currently produces most of the gas it consumes, it is poised to increase its consumption and imports in the near future.

1.3 Gas Reserves and Prospects in Developing APEC Economies

The developing APEC economies offer a more diverse picture in terms of natural gas usage. While some economies already have a developed natural gas sector, others are only beginning to exploit their natural gas resources. Developing APEC economies tend to rely more heavily on oil and coal than natural gas in their energy mix. The major exception is Russia, which relies on natural gas for 53% of its energy generation needs. In contrast, the Philippines relies on oil for more than 60% of its primary energy consumption and much of that demand is supplied by imports. Only China relies on a single source of energy, coal, more heavily than the Philippines relies on oil. Both economies are trying to diversify their energy mix and both economies are turning to natural gas as an alternative and cleaner energy source. Indonesia and Malaysia are two of the world's largest exporters of natural gas in the form of LNG. Peru has plans to develop LNG exports and Papua New Guinea is also interested in this possibility. At the other end of the spectrum, Chile has the lowest level of gas reserves and is also the most dependent on gas imports to meet natural gas demand. Viet Nam is taking steps to better exploit its natural gas reserves for use in its power generation and industrial sectors.

1.4 Competitiveness of Natural Gas versus Other Fuels

Recent increases in natural gas prices may make some APEC economies hesitant to embrace natural gas as the best fuel choice to supply their economies' future energy needs. However, coal prices have recently experienced periods of strong appreciation due to strong demand for power generation globally. With increased demand, limited supply and transportation bottlenecks may continue to push the price of coal upward. In addition, if the costs of the environmental impact of different types of power generation are factored in, it becomes apparent that combined cycle gas-fired power has advantages over traditional coal-fired plants.

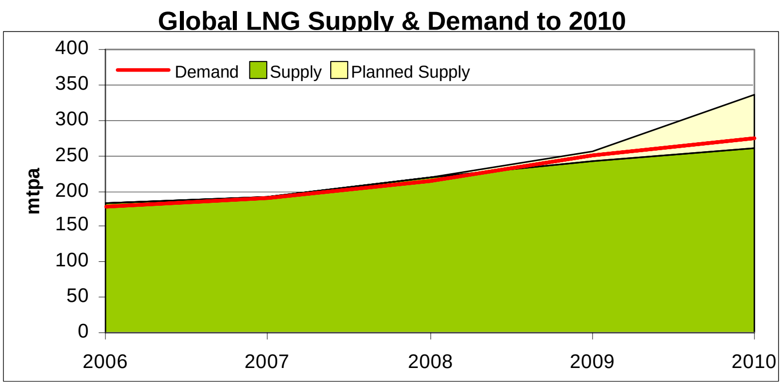


Source: MIT (base case) & ExternE (External Costs)

1.5 Evolution of the LNG Market

The global LNG trade is developing fast, and it is important for developing APEC economies to fully understand the LNG value chain and LNG global markets in order to take full advantage of the potential benefits of LNG, both for exporting and importing purposes. The LNG value chain is composed of production, liquefaction, shipping, and regasification; each part of the value chain is critical, and all are capital intensive. In addition, each step of the value chain presents specific risks that need to be mitigated to finance the end project.

Several factors have driven the growth in the global LNG market including a long history of uninterrupted supply, the speed of construction of gas power plants, cost reductions across the value chain, high oil prices, and an increasing demand for natural gas. Global supply and demand are expected to grow substantially, yet remain tight, through the end of the decade. As more liquefaction capacity is installed, supply constraints may begin to ease at the beginning of the next decade.



Source: Deutsche Bank and Taylor-DeJongh estimates

1.6 Economic and Environmental Conditions for Natural Gas to Become a Viable Energy Source

One of the key drivers of future natural gas consumption in the developing APEC economies will be power generation; it is projected that by 2020 electricity generation will use 45% of the gas supply in the APEC economies. The petrochemical industry is also a large consumer of natural gas and will most likely continue to drive increased utilization. Strengthened environmental standards will also promote the use of cleaner burning and more efficient fuels such as natural gas.

However, natural gas markets do not occur naturally, they must be created. In order for natural gas to fill the energy gap in developing APEC economies, a number of issues must be resolved, including:

- political and institutional barriers
- economic limits (low standards of living)
- inter-fuel competition
- the lack of gas transmission and distribution infrastructure
- the lack of investment in gas-based technology, such as CCGT power generation
- heavy-handed regulatory regimes
- deregulation (if deregulation constrains buyers from committing to long-term offtake or supply contracts or disaggregates buyers so as to reduce their financial capacity to undertake such commitments) and
- the lack of recognition of the environmental benefits and value of gas.

There is no one-size-fits-all solution to these issues. However, governments have many tools that can be used to tailor the development of a natural gas market to their respective economies. Solutions discussed in this report include introducing new technologies and environmental incentives that increase the demand for natural gas and the creation of a regulatory framework that attracts investment. A check list of issues and recommendations for policymakers appears in Chapter 6.

1.7 Utilization of Natural Gas in the Power Generation and Industrial Sectors

Power generation and industry, especially the petrochemical industry, are major end users of natural gas in many APEC economies. Many developing APEC economies, however, do not use natural gas at its maximum efficiency and extract its optimum energy content. The key to increasing the use of natural gas is to invest in infrastructure, which requires major financial investment, either in gas-fired electricity generation, petrochemical or other processing facilities, or gas transportation and distribution networks. In many cases, these investments can only be made if they are supported by factual data and evidence showing the need for the project. Providing the resources necessary to develop and maintain this critical information is one way the international organizations can support the increased utilization of natural gas in the developing APEC economies.

1.8 Case Studies

Many developing APEC economies are taking initiatives to increase their utilization of natural gas. Various projects have been developed, or are currently being developed, that illustrate some of the challenges faced by those who seek to expand the exploitation of natural gas.

China's need for energy is increasing rapidly. Currently, the economy relies heavily on coal. The government recognizes this overdependence and wants to diversify its energy sources. Although China has significant natural gas reserves, they are located far from consumption centers. Therefore China is developing a series of LNG import terminals coupled with gas-fired power plants.

Peru also has large natural gas reserves and is currently trying to develop the Camisea field. An LNG liquefaction plant is planned and various pipelines have been considered, but the project has been continually delayed and still faces a wide array of political, social, and environmental challenges.

The Philippines faced a similar situation when gas was discovered offshore Malampaya 400kms from a major load center; the resource was vital for electricity supply in the economy and its development was a positive sign of the ability of the Philippines to handle large infrastructure projects.

Viet Nam is also exploring options to make the most of its recently discovered gas reserves. The Phu My 2-2 power project was the first independent power project in Viet Nam, and its successful financing through a project finance mechanism made it a landmark deal and a model for future power project development.

Each of these projects illustrated the need for a strong demand and a solid regulatory framework, as well as a robust financing structure to ensure success.

1.9 Policy Measures for the Expansion of Natural Gas Use

Governments have a key role to play in the expansion of natural gas use in the developing APEC economies. Traditionally, in these economies, the natural gas sector has been controlled by state-owned monopolies, which were not necessarily efficient or innovative, but could decide and set prices to benefit consumers or allow a subsidized market to be created. Competition in a lightly-regulated framework ultimately ensures the most efficient allocation of resources and is beneficial to end consumers. A sound regulatory framework is also critical to attract financing and investment, both domestic and foreign, in the natural gas sector. Regulation covers a wide range of issues from technical standards to market entry to pricing to taxation, and the government must ensure it is fair, efficient and transparent to ensure expansion of the natural gas sector.

1.10 Summary and Conclusions

Increased use of natural gas is already an important trend in APEC economies, both developed and developing, and this should accelerate in the coming years. Natural gas provides important benefits, in particular for the environment, which should ensure that APEC economies increase the proportion of natural gas in their energy production and industrial mix.

Numerous natural gas projects are planned in the near future. These projects are very diverse: gas field developments, pipelines, gas-fired power plants, LNG liquefaction and regasification facilities, petrochemical plants, city gas facilities, etc. All projects nevertheless have in common the need to respect certain economic and regulatory conditions to be successful.

Natural gas projects should be economically justified and integrated into an economy’s energy strategy. The financing of natural gas projects is an important component, for which a solid regulatory framework and mitigation of risks are necessary.

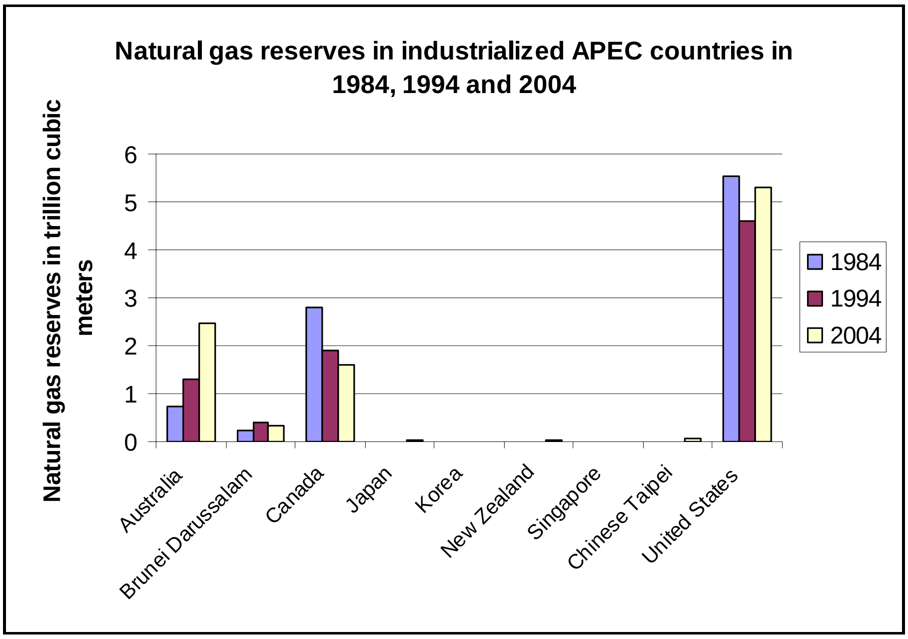
Governments of APEC economies have a pivotal part to play in increasing the use of natural gas as a clean energy source. Governments are responsible for installing adequate regulatory frameworks, designing energy policies favorable to natural gas, and facilitating the dissemination of information on the benefits of natural gas. APEC itself can play an important role by identifying best practices and facilitating information sharing among its member economies.

2 RECENT GAS DEVELOPMENT AND UTILIZATION IN INDUSTRIALIZED APEC ECONOMIES

2.1 Introduction

In this report, the industrialized APEC economies refer to economies meeting the World Bank standard of "high income" and include Australia; Brunei Darussalam; Canada; Hong Kong, China; Japan; Korea; New Zealand; Singapore; Chinese Taipei and the United States. This group offers a diverse natural gas profile. The group is comprised of economies of different sizes and corresponding natural resources endowments, creating both natural gas exporters and importers. Almost all of these economies nevertheless have a developed natural gas sector where much of the natural gas is consumed for power generation.

2.2 Natural Gas Reserves and Production in Industrialized APEC Economies Since 1990



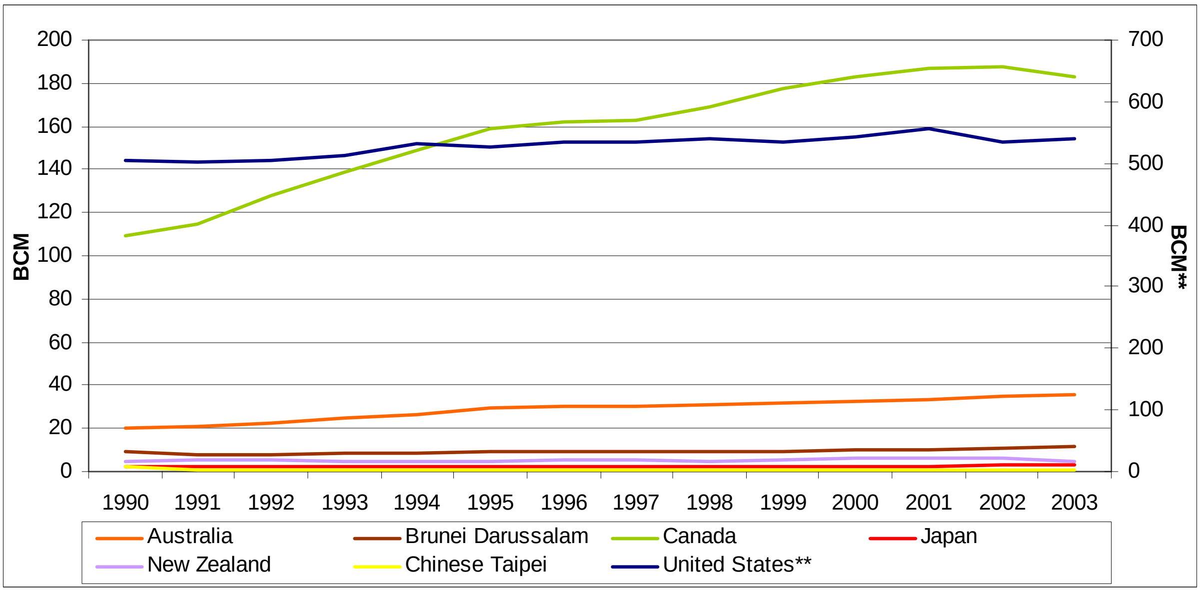
Source: EIA, BP

The United States has the largest gas reserves among the industrialized and developed APEC economies. Australia also has major reserves, and recent natural gas discoveries have furthered the development of its LNG trade. Brunei Darussalam has significant gas reserves, especially considering its small size, and its reserves are significantly greater than internal consumption, allowing it to also be an important exporter of LNG. Japan, Korea, New Zealand, Singapore and Chinese Taipei have insignificant or no natural gas reserves.

The preceding graph only accounts for conventional proven gas reserves, and thus excludes coal-bed methane, tight gas and deep gas. These unconventional gas sources are being explored in numerous economies, particularly in Canada and, to a lesser extent, in the United States to complement supplies from depleting conventional gas fields and in an effort to decrease gas imports from increasingly high-priced sources.

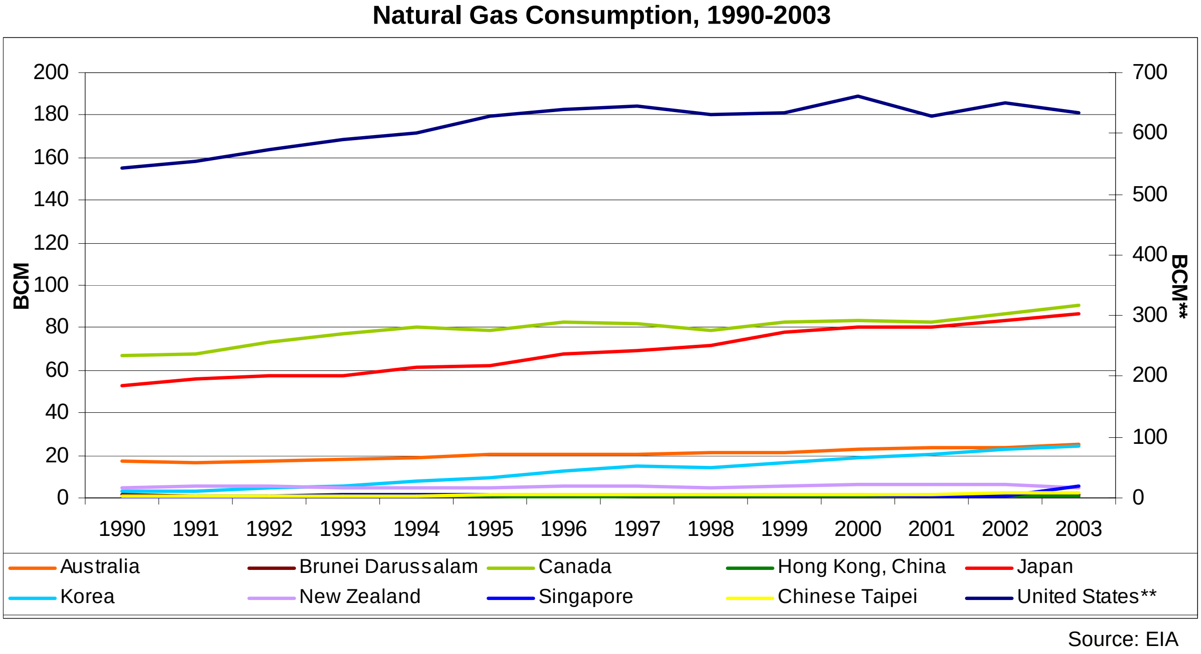
The same patterns are repeated for production. The United States, Canada, and Australia are the largest gas producers among this group of economies. Natural gas production is increasing in Australia while it has reached somewhat of a plateau, or is declining, in Canada and the United States.

Natural Gas Production, 1990-2003



Hong Kong, China; Singapore; and Chinese Taipei had no natural gas production during this period. Source: EIA

Natural gas represents an important energy source for all of these industrialized economies, and the importance continues to grow due to the relatively low-cost and environmental considerations associated with natural gas vis-à-vis other fossil fuels. The United States is the largest natural gas consumer. Japan and Korea also have a long tradition of gas-fired power plants fueled by LNG imports.



2.3 Natural Gas Demand and Supply Since 1990

Demand for natural gas is rising in all APEC industrialized economies, but the way this demand is met varies widely among economies. Japan, Korea, Singapore and Chinese Taipei have little or no domestic production of natural gas, yet each of these economies has a relatively high demand for the commodity. Supply comes in the form of imports, via LNG or pipeline. New Zealand has very limited reserves as well, but has historically chosen to limit its consumption of natural gas to the level of its domestic production rather than rely on imports. It is currently investigating its first LNG import terminal.

Australia, Brunei Darussalam and Canada have a strong domestic gas production that largely exceeds their domestic demand. These three economies are thus net exporters of natural gas. Canada however is facing a decrease in its production due to depleting reserves.

The United States is both an exporter and an importer of natural gas. It is the largest consumer of natural gas among APEC economies and is also a major producer. Part of the domestic production is exported while the United States imports pipeline gas from Canada and increasingly as LNG.

2.4 Projected Natural Gas Demand and Supply to 2010

According to the International Energy Agency (IEA), global natural gas demand is expected to grow by 2.1% per year between 2005 and 2030; in 2020 natural gas is anticipated to become the world's second largest energy source after oil and ahead of coal. Much of the growth in natural gas demand can be attributed to the power generation sector, as many economies select natural gas for the speed of getting new plant on-line and to meet more stringent environmental regulations. Exports of natural gas to industrialized APEC economies are expected to increase substantially in the coming years to meet this growth. Canadian exports to the United States will not be able to keep pace with the rising demand, nor will Indonesian and Malaysian exports to Japan and Korea, prompting these economies to look for new supplies of natural gas. A large portion of new gas supplies are expected to come from other APEC economies (Australia, Russia, potentially Papua New Guinea) and non-APEC suppliers in the Middle East and elsewhere.

According to the IEA, OECD economies in the Pacific (Japan, Korea, Australia, and New Zealand - Brunei Darussalam, Singapore and Chinese Taipei do not belong to OECD) will experience a 2.1% annual growth of their natural gas demand between 2005 and 2030. North American economies (Canada, United States) on the other hand will experience a growth in their natural gas demand of 1.1%, lower than the world average.

2.5 Breakdown of Natural Gas Usage by Sector Since 1990

Power generation is the largest driver of natural gas consumption in the industrialized APEC economies, especially in Japan, Korea and Chinese Taipei. Natural gas is seen as a relatively clean, efficient, and reliable energy source. New natural gas-fired power plants are being built to replace old and inefficient oil- and coal-fired power plants, which have higher fuel consumptions as well as higher levels of carbon emissions. Environmental treaties and policies, such as the Kyoto Protocol and individual national legislation, are also drivers for increased natural gas demand.

Industry is the second largest user of natural gas in the industrialized APEC economies. For example, Singapore's developing petrochemical industry can be linked directly to the recent increase in natural gas imports to the economy. The industrial sector is also the largest domestic consumer of natural gas in Australia, Canada, New Zealand and the United States.

Additional information on each economy can be found in Appendix A of this report.

2.6 Projected Natural Gas Usage by Sector to 2010

Natural gas consumption projections are expected to be the greatest for the power generation sector in almost all of the OECD economies. According to the IEA, natural gas is considered a "better" energy source than coal for power generation because of the lower capital costs of gas-fired plants, higher fuel efficiency, shorter power plant construction lead times, and lower environmental emissions. Therefore, most new power plants to be constructed are expected to be fueled by natural gas where it is available and economical. Approximately 50% of the global natural gas consumption will be used for electric power generation.

Economies that rely heavily on importing LNG to fulfill domestic demand, such as Japan, Korea, Singapore and Chinese Taipei, are expected to increase their LNG imports to supply their increasing demand in electricity consumption. Electric power generation has already been the largest gas-consuming sector in these economies, and this trend is expected to continue.

The same trend applies to Brunei Darussalam. The majority of its natural gas consumption is used for electricity generation, of which the demand is expected to double from 1998 to 2010.

The industrial sector is currently the largest gas consuming sector in Australia, Canada, New Zealand, and the United States. However, the continued growth of natural gas usage will be led by the electric power generation sector. Gas consumption in other sectors is also expected to grow, but not as rapidly as in the electric generation sector.

2.7 Key Drivers for Natural Gas Demand in Industrialized APEC Economies

Power generation is the largest driver of natural gas consumption in industrialized APEC economies, especially in Japan and Korea. Natural gas is seen as a relatively clean, efficient and reliable energy source. New natural gas-fired power plants are being built to replace oil- and coal-fired power plants which have higher level of carbon emissions. Environmental constraints such as the Kyoto protocol and national legislations are thus a driver for natural gas demand.

Growing needs for power generation increase demand for natural gas, but the growth remains far more moderate than in developing economies as most of the power generation infrastructure already exists. The strong growth in LNG demand in the United States for example is caused mostly by the fact that the production of natural gas in North America is slowing.

Industry is the second largest user of natural gas. Singapore's developing petrochemical industry for instance can be linked to the recent increase in natural gas imports of the economy. Industry is also the largest consumer of natural gas in Canada and the United States. However, unlike in developing economies like China, industrialized APEC economies are not expected to experience a surge in industrial usage of gas.

2.8 Key Barriers to Natural Gas Usage in Industrialized APEC Economies

The major barrier to increasing the usage of natural gas in the industrialized APEC economies is the need for new gas-related infrastructure (LNG regasification terminals, pipelines, storage facilities) to be built and the difficulties of developing this in a reasonable timeframe.

In most industrialized APEC economies, the natural gas sector is already well developed, and because most of these economies are not expected to experience large population growths and have long ago finished their initial industrial development cycle, their energy demand growth will only increase moderately over the next 20 years. Some economies, such as Japan and Korea, already depend heavily on natural gas for their power generation, and are actually discussing reducing their dependency on natural gas rather than increasing it. In other economies, such as the United States, the situation is slightly different as demand for gas is increasing, and there is a need to find alternative supply sources, such as LNG and other non-conventional gas.

The difficulty of building new infrastructure is a major barrier to increasing natural gas usage. Gas can be transported either by pipeline or in its liquid form as LNG. Most viable pipeline projects to connect industrialized APEC economies to gas supply sources have already been realized. There is still room for LNG import regasification terminals, but they often face community opposition, permitting hurdles and are very capital intensive. Specifically, in the United States many communities have resisted new LNG terminals for presumed safety and environmental reasons.

Another barrier, although it may prove to be only temporary, is the current high gas prices. High oil and gas prices have prompted many economies to search for alternative energy sources such as energy produced using clean coal technologies or nuclear power.

Despite these difficulties, natural gas is a well-developed energy source in all industrialized APEC economies, whether these economies are importers or exporters of gas. Natural gas usage is expected to grow in this group, but at a slower pace than in developing APEC economies, which are reviewed in the next chapter.

3 REVIEW OF NATURAL GAS RESERVES AND PROSPECTS FOR GAS GROWTH IN DEVELOPING APEC ECONOMIES

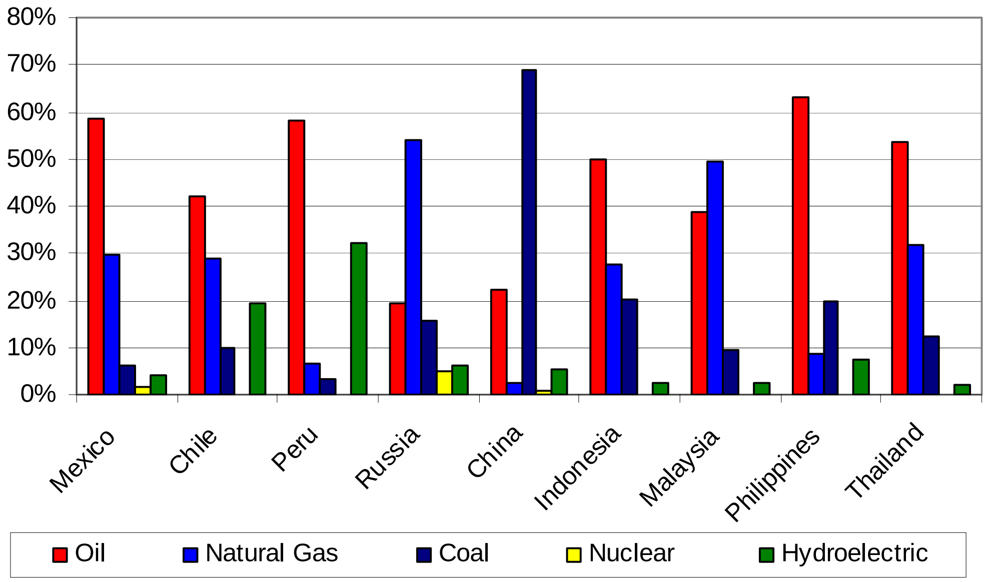
3.1 Introduction

The developing economies that are members of APEC are diverse across cultures and geographies. It is not, therefore, unexpected that energy consumption and resources vary widely throughout these economies as well. This chapter provides a survey of the energy resources of APEC's developing economies, the consumption patterns of these economies, and the role of natural gas in the energy strategy and infrastructure planning of these economies.

3.2 Primary Energy Mix in Developing APEC Economies

Exhibit 3.1 below shows the breakdown, on a percentage basis, of primary energy consumption for the relevant economies.

Exhibit 3.1: Primary Energy Consumption[2]*



From the data, it can be seen that many of these economies depend heavily on oil for energy production. The Philippines relies on oil for more than 60% of its primary energy consumption and much of that demand is supplied by imports. Only China relies on a single source of energy, coal, more heavily than the Philippines relies on oil. Both economies are trying to diversify their energy mix and both economies are turning to natural gas as a major alternative energy source. Prior to 2001, the Philippines consumed

[2] Derived from data from the BP Statistical Review of World Energy 2005

* Insufficient data for the economies of Papua New Guinea and Viet Nam was available to include them in this chart, but the available data is discussed at length below.

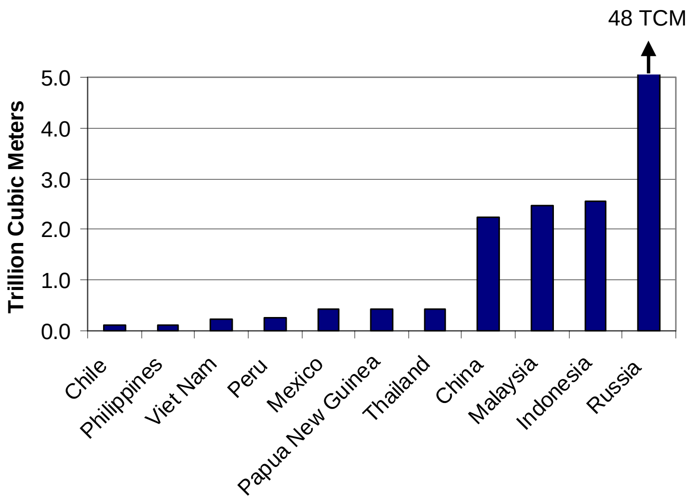
no natural gas. However, with the discovery of the Malampaya gas field, the economy began to grow its use of natural gas and reduce oil consumption. In only four years, natural gas has gone from zero to almost 10% of its primary energy mix.

In China, natural gas makes up the smallest percentage proportion of primary energy consumed in any of the surveyed economies, however the sheer size of its economy makes this statistic deceiving; in 2004 China consumed 39 bcm of natural gas, more than any other surveyed economies. Large domestic coal reserves made coal the dominant energy source in China's economy. Although coal will not be supplanted in the foreseeable future, environmental concerns and a growing emphasis on energy efficiency have led the Chinese government to focus on alternative sources of energy, one of them being natural gas. In addition, increased growth in gas-fired power generation is expected to spur demand beyond the limits of domestic gas production, creating the need for natural gas imports for the first time. A case study on China's strategy to use imported LNG is included in Chapter 8 of this report.

3.3 Natural Gas Reserves in APEC Economies

Exhibit 3.2 below shows the level of natural gas reserves found in each of APEC's developing economies. According to the BP Statistical Review, the sum of these reserves makes up 31.85% of the world's total natural gas reserves.[3] However, the overwhelming majority of these reserves are found in Russia, which has the largest natural gas reserves of any single nation in the world. If Russia is removed from the total, then these economies make up just over five percent of the world's proven gas reserves.

Exhibit 3.2: Proved Natural Gas Reserves (2004)[4]



[3] The BP Statistical Review does not include reserve figures for Chile or the Philippines; the data included for these countries is from the EIA.

[4] BP Statistical Review 2005

How these economies utilize their reserves varies a great deal according to the overall size of their respective economy and the usage of natural gas relative to the size of their reserves. In Russia, natural gas is both the primary energy source and a major export. Indonesia and Malaysia are two of the world's largest exporters of natural gas in the form of LNG. Peru has plans to develop LNG for export and Papua New Guinea is also interested in the possibility of exporting LNG.

At the other end of the spectrum, Chile has the lowest level of reserves and is also the most dependent on gas imports to meet electricity demand. Most of its imports come via pipeline from Argentina, but Chile is also exploring the possibility of diversifying its supply source by building an LNG regasification terminal. Viet Nam is taking steps to better exploit its natural gas reserves for use in its power generation and industrial sectors. Each economy's individual energy strategy is discussed below. More detailed information on each economy is included in Appendix B of this report.

3.4 Chile

	Natural gas	Oil	Coal
Proven Reserves	99.1 bcm	150 mm bbls	1.3 bn short tons
Production	999.6 mmcm	18,400 bbls/d	0.5 mm short tons

Source: EIA - Country Analysis Brief, Chile

Chile's production of natural gas is minimal. Argentina is Chile's main source of natural gas imports. In 2004, Argentina suffered an energy crisis and cut natural gas exports to Chile. Production at power and methanol plants in Chile has declined due to shortages in gas supplies. While Chile is interested in receiving exports from Bolivia, political tension between the two economies makes an energy trading relationship elusive. The Chilean government is a major advocate of regional energy integration with its immediate neighbors (Argentina, Peru, Brazil, and eventually Bolivia), and of the creation of an energy "ring" through which resources are shared.

Chile is interested in continuing to develop its gas-fired power plant capacity. By 2020, the economy aims to increase the proportion of natural gas in its energy mix to 43%[5], and has plans to develop 10 new combined-cycle gas-fired power plants. At the same time, the Chilean government wants to diversify its energy mix away from over-dependence on Argentine gas sources. To this end, Chile has begun to pursue plans for possible LNG importation.

[5] EIA – "An Energy Overview of Chile"

3.5 China

	Natural gas	Oil	Coal
Proven Reserves	2.23 tcm	17.1 bn bbls	104.2 bn short tons
Production (2004)	40.8 bcm	3.5 mm bbls/d	1.8 bn short tons

Source: BP Statistical Review of World Energy 2005

Coal is currently China's most plentiful fossil fuel resource and its most important source of energy. China's major gas fields are located in the western part of the economy, making transportation to eastern demand centers a major undertaking. CNPC recently completed the West-East pipeline, which runs from major gas fields in the Xinjiang region to Shanghai. Offshore gas fields in the East China Sea are currently at the center of a dispute between China and Japan over territorial rights.[6]

The EIA predicts that China's consumption of natural gas will double by 2030.[7] This growth will be driven in large part by the increased use of gas for power generation, as well as increased residential consumption in urban areas. While some of the rising demand will be fulfilled through increases in domestic production, a large portion will come from pipeline imports and imported LNG.

The Chinese government's overall energy strategy has focused on securing the energy reserves needed for future growth while increasing the attention placed on environmental protection and energy efficiency. Increasing the role of natural gas in the economy's energy mix has been vital to meeting these objectives. This was evidenced by the government's 2001-2005 Five-Year Plan (FYP), which called for the doubling of domestic natural gas production and the construction of 14,500 km of gas pipeline.[8] One of the keys to growing the role of natural gas in China's energy mix is development of the necessary infrastructure. However, lack of a comprehensive regulatory framework governing the natural gas sector has made the development of the needed infrastructure difficult. Most of the regulation has been put in place by local authorities, and the effect has been a confusing mix of laws that fosters uncertainty and inefficiency. In this environment it is difficult to attract the investment necessary to finance the large amounts of capacity additions necessary to realize the government's natural gas objectives. In response to this, the Chinese government, in collaboration with the World Bank, has been working to establish a more unified code that will establish a solid base for gas market development; however, progress has been slow.

CNPC, Sinopec, and CNOOC are the main players currently active in the development of China's natural gas infrastructure and much of their activity has focused on developing the import capacity needed to

[6] *Ibid*

[7] Li Zhidong, Ito Kokichi, and Komiyama Ryoichi. "Energy Demand and Supply Outlook in China for 2030." The Institute of Energy Economics, Japan. August, 2005.

[8] *Developing China's Natural Gas Market*. International Energy Agency. 2002, p. 78.

meet future demand. CNPC was the major sponsor of China's most important pipeline project to date, the West-East pipeline, while CNOOC has taken the lead in developing LNG import terminals. One characteristic of the LNG terminals has been the required concurrent development of gas-fired power plants that can provide steady demand for a portion of the imported LNG while demand from other sectors is established. Much of the financing for infrastructure projects is supplied by domestic commercial banks. The government has attempted to provide incentives for foreign investment in infrastructure projects and has been successful to some extent. However, many of the incentives have been granted on a project-by-project basis, reducing transparency within the sector overall and increasing the difficulty of attracting sustained foreign investment.

3.6 Indonesia

	Natural gas	Oil	Coal
Proven Reserves	2.56 tcm	4.7 bn bbls	5.5 bn short tons
Production (2003)	73.6 bcm	1.2 mm bbls/d	132.4 mm short tons

Source: EIA - Country Analysis Brief, Indonesia

Indonesia is one of the largest exporters of LNG in the world. In terms of LNG market share, Indonesia has 22.9% of the world market share and 33% of the Asia-Pacific market. Because of declining oil production, Indonesia's government has begun using its natural gas resources for domestic power generation, putting strong pressure on LNG suppliers to meet their delivery contracts. Indonesian gas, however, is currently up against stiff competition from other suppliers, such as Australia, Brunei Darussalam, Malaysia, and Qatar. In addition, most of the economy's long-term LNG contracts with Japan, Korea, and Chinese Taipei are expiring in the near term and there is a high probability that the agreements will be scaled down due to diminishing supply, unless alternative gas sources are found and brought on line.

Indonesia has limited infrastructure and is particularly lacking in its domestic gas transmission network. As a result of rising domestic demand for natural gas, and in an attempt to boost gas production and reduce oil consumption, the Indonesian government issued interim permits to nine companies allowing them to distribute natural gas to industrial consumers.

Upcoming infrastructure development projects include BP's 7.5 mtpa Tangguh LNG project in Papua province. Tangguh has more than 14 Tcf of natural gas reserves. In addition, state-owned electricity company PLN has entered into an agreement with Pertamina to construct an LNG regas terminal in Cilegon in West Java. The project will help reduce dependence on coal for power generation. Pertamina has also announced plans to build an LNG liquefaction terminal, to be completed by 2010, in Donggi in Sulawesi.

3.7 Malaysia

	Natural gas	Oil	Coal
Proven Reserves	2.12 tcm	3.0 bn bbls	-
Production (2004)	48.1 bcm	855,000 bbls/d	-

Source: EIA - Country Analysis Brief, Malaysia

Natural gas production has been increasing in recent years, reaching 48.1 billion cubic meters in 2004. If the level of production remains unchanged, gas reserves are expected to last only 34 years. JDA, the Malaysia-Thailand Joint Development Area, is considered the most active gas development area for the economy. Malaysia also has the world's largest liquefaction center in a single location, Bintulu LNG, with a total capacity of 23 million mt a year. Domestic consumption of gas has been expanding rapidly in recent years with much of the demand coming from the power sector.

In an effort to reduce the dependence of the power sector on oil and gas, especially given increasing oil prices, the government introduced the Eighth Malaysia Plan (2001-2005) which presents coal as a major alternative for oil and gas. All exploration projects are to be done in partnership with the national oil company, Petronas. In an effort to ensure a continuous and cost-effective oil and gas supply in the future, the government has approved power generation schemes that support its policy regarding the development of gas fields. Developments in the oil and gas sector will be further enhanced to strengthen Malaysia's share in the domestic and overseas markets. Malaysia's strategy is to invest in more development and research to explore more fields, as only half of the identified exploration area so far has been explored. Malaysia announced on June 14, 2004, during the Asian Annual Oil and Gas Conference in Kuala Lumpur that its goal is to increase oil and gas production by 3% per year for the next five years.

3.8 Mexico

	Natural gas	Oil	Coal
Proven Reserves	420 bcm	14.8 bn bbls	1.1 bn short tons
Production (2004)	37.1 bcm	3.8 ml. bbls/d	8.2 mm short tons

Source: BP Statistical Review of World Energy June 2005

Mexico has the sixth largest gas reserves in the Americas, It is projected that by 2012, 45% of the economy's natural gas demand will come from the power sector, and that natural gas-fired plants will account for 60% of Mexico's power capacity. Mexico's demand for natural gas has been estimated by its Secretaría de Energía (SENER) to increase to 81.6 bcm by 2010.

The two main goals of the Mexican government are to increase domestic production of oil and gas, and to develop LNG regasification import terminals. In 2000, Pemex introduced a Strategic Gas Plan that called for an increase in domestic natural gas production to 82.7 bcm by 2008.[9] The plan outlined the following goals: 1) increase natural gas production through multiple service contracts; 2) diversify foreign natural gas sources by importing more LNG to decrease dependence on domestic and U.S. production; 3) flare less associated gas; 4) increase natural gas transport, distribution, and storage capacity, specifically increasing interconnection capacity between the Mexican and U.S. pipeline grids; and 5) increase proven reserves by allotting more money to exploration. Five years into this program, natural gas production has increased at a rate of 6% a year to reach 135.5 Mcm/d by the end of 2005; two LNG terminals are under construction, with others being developed; gas flaring has been reduced from 5.5% total production in 2002, to 3.7% of total production at the end of the third quarter of 2005[10].

3.9 Papua New Guinea

Papua New Guinea has proven reserves of 170 million barrels of oil. Oil production is estimated at 46,200 bbl/day and consumption is estimated at 15,000 bbl/day. Natural gas production and consumption are both estimated at 110 million cubic meters. Reserves are estimated at 385.5 billion cu m. PNG has no coal or other energy resources. Power generation makes up nearly 100% of gas demand, and will continue to do so through 2020.

Papua New Guinea is currently self sufficient in its energy consumption and could be a natural gas exporter with sufficient investment in infrastructure, exploration and development. ExxonMobil is spearheading the development of a natural gas pipeline that would run from the Papua New Guinea highlands to the central eastern coast of Queensland, Australia. There may also be potential for the development of an LNG project.

3.10 Peru

	Natural gas	Oil	Coal (2003)
Proven Reserves	246 bcm	930 mm bbls	1.17 bn short tons
Production	0.56 bcm	112,000 bbls/d	20,000 short tons

Source: EIA - Country Analysis Brief, Peru

Peru is currently a net importer of crude oil, natural gas and coal. With the development of the Camisea gas fields, Peru is poised to become a net exporter of natural gas in the next few years, as Camisea's production potential exceeds domestic demand.

Camisea is the heart of natural gas developments in Peru. The field itself began production in August 2004, and the gas is transported by pipeline to Lima and Callao for household and industrial consumption. As a complement to the Camisea project, Hunt Oil, SK Corporation, and Repsol YPF are

[9] EIA – Country Analysis Brief, Mexico

[10] PEMEX – Financial Results Report Sep 30th, 2005

currently developing the Peru LNG project. The objective is to build an LNG liquefaction facility to export natural gas to Mexico and the west coast of the United States. Other potential projects around the Camisea gas fields include a pipeline to Chile. Several power projects using gas from Camisea are also under development.

3.11 Philippines

	Natural gas	Oil	Coal
Proven Reserves	107.6 bcm	200 mm bbls	260.1 mm short tons
Production (2005)	2.8 bcm	25,600 bbls/d	2.2 mm short tons

Source: EIA - Country Analysis Brief, Philippines

Despite the fact that the Philippines has 107 bcm of proven natural gas reserves, before the commercialization of the offshore Malampaya gas field in 2001 there was no significant gas production.[11] Currently, Malampaya provides gas to three power plants, totaling 2,700 MW in capacity.

The Philippines will continue to depend on oil imports for meeting the economy's energy demands throughout the next ten years.[12] The government's first goal has been to decrease the dependency on oil and to increase the security of energy supply through further investing in the gas and renewable sectors. Another major goal has been to assure that the electricity shortages of the 1990s are not repeated. The Philippines is considering the possibility of investing in regasification terminals to import LNG from Australia, Brunei Darussalam, Indonesia, Malaysia, or Qatar. This investment, if finally undertaken, will be complemented by two pipelines, one 100 km from Batangas to Manila and one 150 km from Bataan to Manila.[13]

3.12 The Russian Federation

	Natural gas	Oil	Coal
Proven Reserves	48.0 tcm	72.3 bn bbls	142.9 bn short tons
Production (2005)	589.1 bcm	9.3 mm bbls/d	254.8 mm short tons

Source: BP Statistical Review of World Energy June 2005

Russia is home to the world's seventh largest oil reserves, which, at the end of 2004, BP estimated at 72.3 billion barrels of proven reserves.[14] Russia also possesses the world's largest gas reserves, holding

[11] *Ibid*. p.3

[12] *Ibid*. slide 9 and slide 11

[13] Asian Development Bank, Technical Assistance to the Republic of the Philippines for Institutional Strengthening for the Development of the Natural Gas Industry October 2003. p.1-2

[14] *BP World Energy Review*, 2005.

around 48 tcm and the world's second largest recoverable coal reserves, behind the United States, with 143 billion short tons.

The IEA predicts that Russia will remain the world's largest gas exporter throughout its projection period to 2030. Net exports will continue to rise with increased imports from Central Asia to enable higher exports to Europe.[15] To boost natural gas and oil production, the Russian government has initiated a gradual increase of domestic gas prices as an incentive to producers. In addition, independent gas producers now have increased access to the state-owned pipeline system. More favorable tax policies are in place to stimulate the development of small and medium fields, rehabilitation of more mature fields, and the development of more technically complex gas reserves.

The gas transmission network faces bottleneck issues. Two major gas pipelines are currently being considered: the Yamal-Europe II and the North European Gas Pipeline. Yamal-Europe II would expand the Yamal-Europe I pipeline, which transports gas from Russia to Poland and Germany via Belarus. The upstream gas industry is also in need of major investment. Russia's Ministry of Economic Development estimates that US$160 billion is required between 2005 and 2015. To reach new export markets, namely North America, South-East Asia, and Great Britain, Gazprom is considering LNG export facilities at Murmansk, Yamal, and Shtokman. In the meantime, the Sakhalin-II developers have already begun construction of Russia's first LNG plant.

3.13 Thailand

	Natural gas	**Oil**	**Coal**
Proven Reserves	376 bcm	583 million bbls	1.5 bn short tons
Production	22.6 bcm	259,000 bbls/d	20.7 mm short tons

Source: EIA - Country Analysis Brief, Thailand

Much of Thailand's natural gas is used for generating electricity. In 2001, Thailand completed its program for the conversion of almost all oil-fired electric power plants to natural gas. Demand for natural gas is expected to rise at a 5%-6% annual rate over the next five years.

In May 2005, the Thai government announced a US$20 billion spending package for the economy's energy sector. The plan aimed at optimizing the use of hydrocarbon fuels, improving energy efficiency, and increasing the use of renewables. The plan includes US$3.2 billion for new gas pipelines and expansion of refineries, US$8 billion to build new petrochemical plants, and US$351 million to enlarge oil tank farms.

[15] *Ibid.*

3.14 Viet Nam

	Natural gas	Oil	Coal
Proven Reserves	192 bcm	600 mm bbls	165 mm short tons
Production (2004)	2.8 bcm	366,400 bbls/d	17.6 mm short tons

Source: EIA - Country Analysis Brief, Viet Nam

Currently all the natural gas produced in Viet Nam, which is not flared, is used for domestic consumption. The largest gas producing area in Viet Nam is the Cuu Long basin, a major source of associated gas from oil production. Two natural gas fields are also exploited in the Nam Con Son and the Northern Red River basins. The gas is primarily used to power the Phu My complex, which is discussed in further detail in Chapter 8 of this report.

The Vietnamese government is developing the economy's energy production capacity to keep pace with the economy's growth and to increase exports. PetroVietNam, Viet Nam's state-owned oil company, has come up with a Gas Utilization Master Plan (GUMP) to make the most efficient use possible of the economy's natural gas reserves. The first step of the implementation of GUMP in the 1990s was the use of associated gas from the White Tiger oil fields for power generation and in an LPG plant. For the 2003-2010 period, PetroVietNam is studying the possibility of building a gas pipeline between Phu My and Ho Chi Minh City, as well as developing several small pipelines in the south of the economy to better link gas production centers and populated areas. However, the main projected use of natural gas is for power generation, and this will be undertaken in cooperation with Electricity of Viet Nam (EVN). Fertilizer projects will also be combined with power plants in integrated centers on the model of Phu My.

4 THE COMPETITIVENESS OF NATURAL GAS VERSUS OTHER FUELS

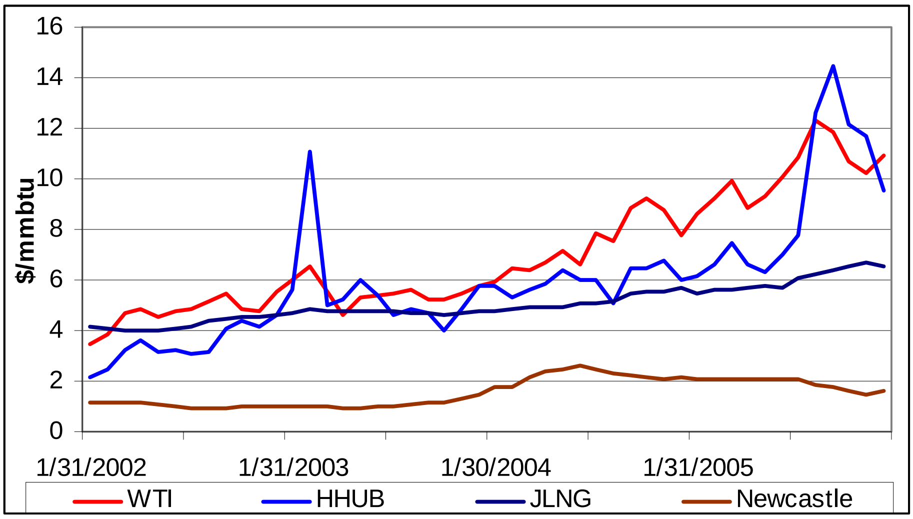
4.1 Introduction

The price of natural gas has become an issue of some concern over the last several years in many world markets. This chapter examines the nominal cost of gas as compared to other fuels widely available in the APEC region. Coal is often seen as the major competitor of natural gas, especially as a fuel for power generation. For this reason, this chapter also reviews recent global trends in the cost, price and availability of coal; compares the overall competitiveness of natural gas versus coal; and assesses the premium that natural gas should command over coal due to the more environmentally friendly properties of gas.

4.2 Unit Cost of Fuel Currently Available

The last several years have seen a dramatic rise in energy prices. The graph below compares the prices of several types of fossil fuels from the beginning of 2002 to the end of 2005 on a U.S. Dollar/mmbtu basis.

Exhibit 4.1: Fuel Prices, 2002 - 2005 ($/mmbtu)



Source: Bloomberg and Taylor-DeJongh

The West Texas Intermediate (WTI) index shows the spot price of crude oil and is a recognized benchmark for global oil prices. The Henry Hub (HHUB) index is the leading natural gas spot price index in the United States. The Japanese liquefied natural gas (JLNG) price is the average price of LNG cargos imported into Japan, the world's largest consumer of LNG. The McCloskey/Argus Newcastle index shows the spot price of coal FOB Newcastle, Australia. Each of these indices has shown some price appreciation over the last four years, but the prices for oil and gas have grown much more substantially than the price of coal. The table below compares price appreciation and price volatility of each of these fuels.

Exhibit 4.2: Fuel Price Appreciation & Volatility (2002 - 2005)

	% change	Standard Deviation (on a $/mmbtu basis)
West Texas crude	+ 213.3%	2.30
Henry Hub gas	+ 340.7%	2.66
Japan LNG	+ 55.7%	0.72
Newcastle coal	+ 43.9%	0.55

Over this period coal prices have shown the most stability by posting both the lowest amount of price appreciation and the lowest overall volatility. However, at times the price of coal FOB Newcastle has appreciated much more sharply than the prices of oil or gas. From July 2003 to June 2004 the price of coal at Newcastle rose by 163% before dropping back to lower levels. During this same time period the prices of oil on the WTI and gas at Henry Hub rose 23% and 13%, respectively. It stands to reason that the high price of natural gas will increase the demand for coal as a substitute, and that this increased demand will also lead to longer periods of sustained increases in coal prices.

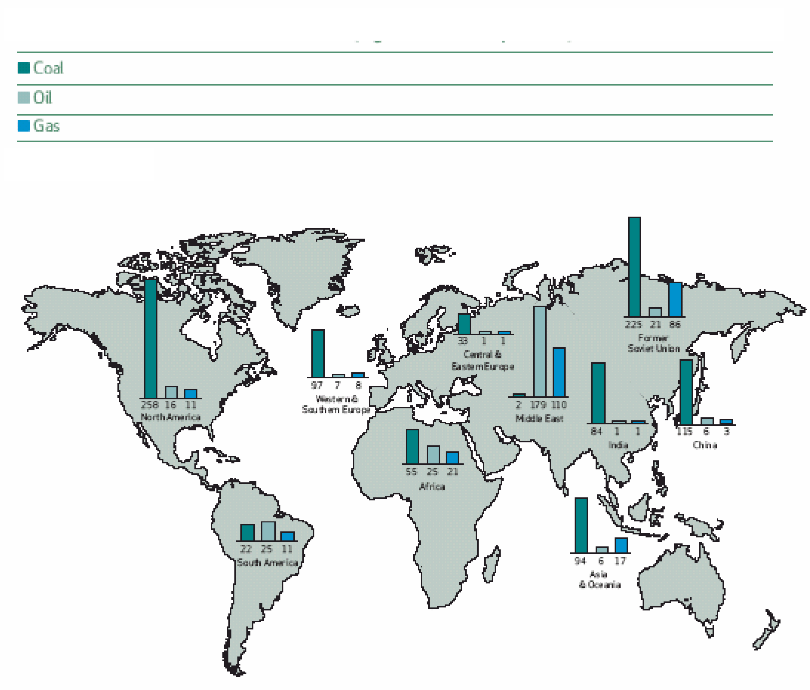
It is also interesting to note that price of LNG imports to Japan have also risen much less than that spot prices of oil and gas as well as exhibited lower volatility. This is largely due to the long-term nature of LNG contracts, with a price formula that contains elements unrelated to the oil price, as well as the prevalent use of a revenue-sharing pricing model, often referred to as the “Japanese model” or the “S-curve model,” in these contracts. LNG pricing contracts are discussed in more detail in Chapter Five.

Natural gas also competes against all other forms of energy, including nuclear and renewable, and as is the case with coal the competition most often occurs in the realm of power generation. However, as is discussed in more detail below, the relationship to fuel costs in the overall cost structure of nuclear power and renewable power is significantly different from that of coal and natural gas. The major cost component of both nuclear and renewable power plants is the upfront capital investment and the cost of generating electricity is comprised mainly of capital recovery costs. Fuel costs make up a marginal portion of the overall cost structure for these two forms of power generation — in the case of renewable energy fuel costs are non-existent (except for biomass) — and therefore the cost competitiveness of power generated by these two forms of energy has much less commodity price exposure.

4.3 Recent Trends in the Cost, Price and Availability of Coal

The fuel that most often competes with natural gas, especially in industries like power generation and steel production, is coal. As the map below shows, coal is the most widely disbursed fossil fuel, with economically recoverable reserves located in over seventy countries.

Exhibit 4.3: Location of the World's Main Fossil Fuel Reserves



Source: World Coal Institute

Although coal reserves are widely disbursed globally, in the APEC region the vast majority of reserves are found in the United States, Russia, China and Australia. According to BP's 2005 Statistical Review, these four economies hold over 97% of APEC's coal reserves, with the US alone accounting for over 40% of available reserves.

As the graph and table in the second section of this chapter indicate, the price of coal has risen substantially over the past several years. This trend has been driven by a number of factors. One important factor has been the increase in global demand for steel. As the market for steel has cooled, so has the demand for and price of coal. Increased Chinese demand has also been a factor. The EIA states that a slump in Chinese demand at the beginning of the decade increased the amount of Chinese coal available for export and depressed prices. However, in recent years China's demand for coal has picked back up, tightening supply and bolstering prices.

As the demand for coal has increased, infrastructure bottlenecks — both in production and transportation — have contributed to the rising cost of coal. Increasing demand means that mine production must be expanded and coal reserves that are more difficult to mine, and thus more expensive, must be exploited. Transportation also becomes a challenge. A report published by Platts states that during the end of 2004, shipping charges on coal exports from Australian, Chinese and Indonesian ports to Japan and Korea reached $15-$20 per metric ton (approximately $0.60-$0.80 per mmbtu), well above the more normal $10-$12 range.[16] Overland transportation is also becoming an issue, especially in the US and China, as the growing demand for coal is creating bottlenecks on the railways used to transport cargos from mines to demand centers.

A final trend may be an increase over the next several years in the amount of coal used for power generation. At the beginning of the decade, much new build power generation was gas-fired, especially in the US. However, high gas prices and concerns about its availability have made firms less willing to build these types of plants. In its reference case in the most recent Annual Energy Outlook, the EIA expects that through the year 2030 65% of additional generation capacity in the US will be coal-fired.[17] Indonesia recently announced that it was launching 2,270 MW worth of power projects, and all but 500 MW will be coal-fired. Power plants fired by coal usually take three or four years to build, meaning that there is a significant delay between investment decisions and actual start of operations. In the face of today's high gas prices, more decisions to build coal-fired power plants will be made. As this demand comes online over the next couple of years, bottlenecks in the current coal production and delivery infrastructure may become even more apparent and lead to more increases in the price of coal.

4.4 The Competitiveness of Natural Gas for Power Generation

Natural gas faces some of its most fierce competition in the area of power generation. The power sector is critical for natural gas because strong demand for power generation is essential to anchor the market for natural gas and justify investments in the complementary transportation and delivery infrastructure. Most APEC economies now face major decisions regarding the type of power generation that should be developed in order to meet the needs of their growing economies. Many of these decisions will represent an attempt to balance the costs of the electricity produced against other concerns such as exposure to the underlying commodity serving as fuel and the environmental impact of the generation facilities. The next two sections will attempt to provide a frame of reference for these discussions.

Most APEC economies are currently faced with the highly decentralized "decision" of what mix of coal- or natural gas-fired power facilities to utilize, while many are also pursuing renewable energy when it is viable and some are considering nuclear power. In 2003 the Massachusetts Institute of Technology (MIT)

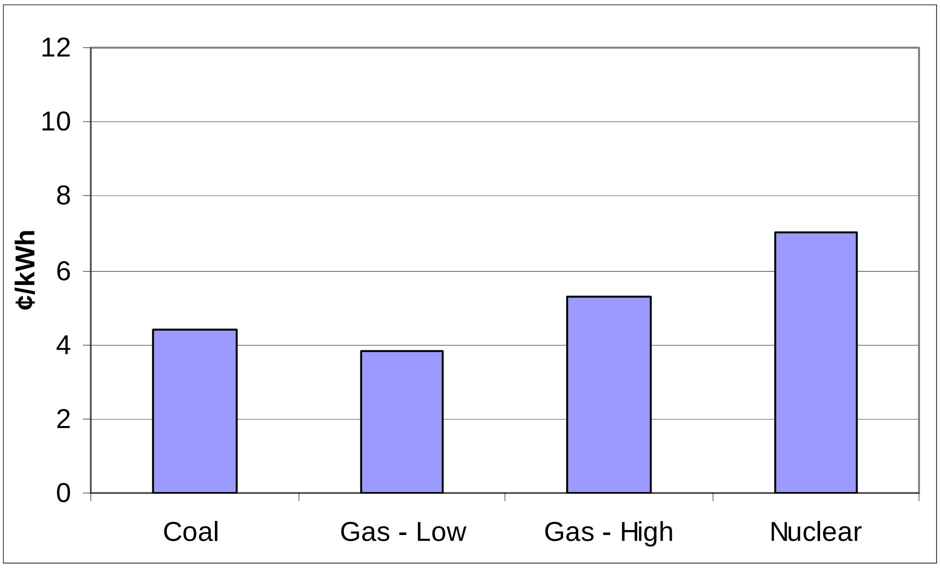
---

[16] Ryan, Margaret. *Platts Insight*. "Coal markets squeeze producers." December, 2005.

[17] Energy Information Administration. *Annual Energy Outlook, 2006.* p. 83.

published a comprehensive report evaluating the viability of nuclear power in the United States. One portion of the study compared the real, levelized cost of electricity produced from nuclear, coal- and gas-fired power plants. The base case comparison is listed below.

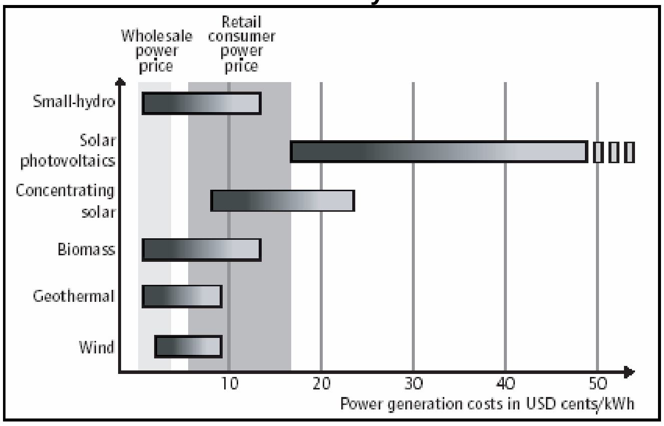
Exhibit 4.4: Cost of Electricity – Coal, Gas & Nuclear[18]



The low gas price assumed in this study is \$3.50/mmbtu, increasing at 0.5% per year, while the high scenario assumes a price of \$4.50/mmbtu with fuel costs rising at a rate of 2.5% per year. The assumed price of coal is \$1.20/mmbtu, increasing at 0.5% per year.[19]

The cost estimates above can be compared to the cost of electricity generated by renewable power shown below.

Exhibit 4.5: Cost of Electricity – Renewable Power[20]



[18] Massachusetts Institute of Technology, *The Future of Nuclear Power*. 2003. p. 42.

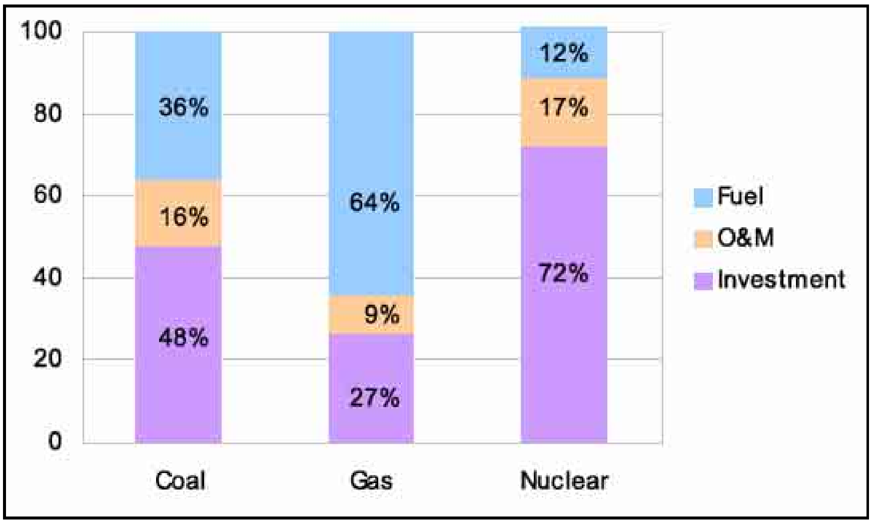
[19] A table of all the assumptions used by MIT in this study is presented in Appendix 3.

[20] International Energy Agency, *Renewables for Power Generation*. 2003. p. 20.

As the graph shows, under optimal conditions renewable power is able to compete with both fossil fuels and nuclear energy. However, optimal conditions are often difficult to achieve as sites suitable for the development of renewable power are often far from demand centers and require the construction of expensive transmission lines. Renewable power can also be relatively unreliable, making it less effective as a source of base load supply.

The cost structures of these four alternative sources of electricity fall along something of a continuum. Natural gas-fired CCGT technology is the least capital-intensive and can be constructed in the quickest amount of time. The largest portion of the cost of electricity generated by CCGTs is the fuel cost, leaving these types of plants more exposed to the underlying commodity risk than their competitors. Capital costs make up a larger portion of the overall costs of generation in a coal-fired plant and fuel costs, while still significant, are less of a percentage of total electricity costs than in a CCGT. The cost of electricity generated from nuclear power is largely made up of capital recovery costs, while fuel costs are marginal. Most forms of renewable power have no fuel costs (biomass is the exception), and thus capital costs are also the most significant piece of the cost structure of renewable power plants. The graph below shows representative costs structures for nuclear, coal and gas-fired power.

Exhibit 4.6: Power Generation Cost Structure[21]

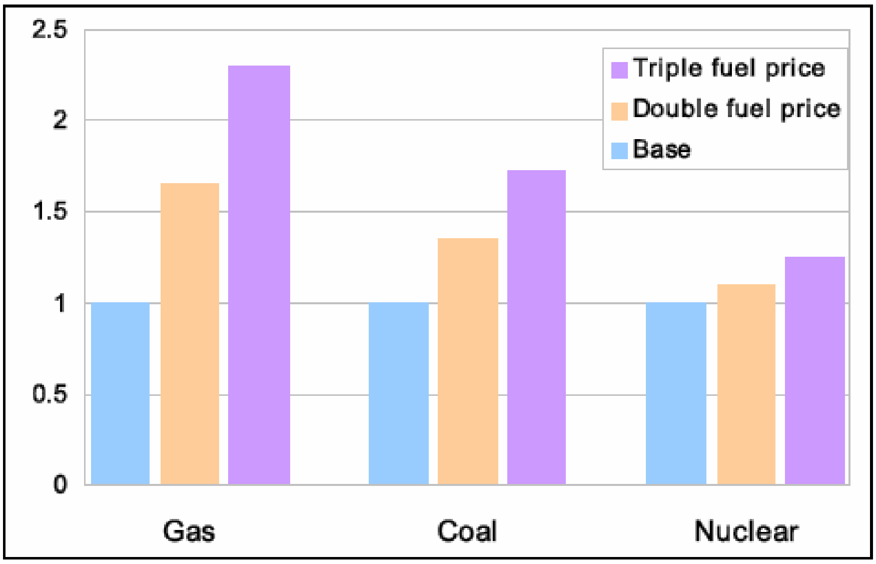


Because fuel costs make up such a small proportion of the overall cost structure of nuclear power, the price of nuclear power is much less sensitive to uranium prices than natural gas or coal-fired power plants

[21] APERC, *Nuclear Power Generation in the APEC Region*, 2004. p. 102.

are to the price of their respective fuels. The graph below gives an idea of how the cost of electricity generated can change for each type of power.

Exhibit 4.7: Fuel Price Sensitivity[22]



Higher sensitivity to fuel prices on the part of CCGT plants equates to greater exposure to commodity price risk on the part of the investors in these plants. This is especially true in deregulated markets such as the United States, where electricity generation is competitive. CCGT plants constructed and financed under the assumption that they would serve as baseload generators may be pushed to a different part of the load curve as gas prices increase. This can have a negative impact on the plant's economics and on its ability to service its debt. However, CCGT plants in economies such as Japan may face less exposure to volatile gas prices because their fuel supply has historically been sourced in the form of LNG under long-term contracts. Figure 4.2 showed that the price of LNG tends to be much less volatile than the spot price of natural gas, mainly due to the effects of long-term purchase agreements. This may have implications for economies such as China that plan to increase the use of natural gas in power generation mainly through the importation of LNG, with reported indexing of prices less linked to crude oil prices.

Although from a cost perspective most analyses of the competitiveness of different types of power generation focus on the price of the fuel, the impact of capital costs should not be overlooked, especially in developing economies where interest rates tend to be higher. Investments in coal-fired and nuclear plants are much more capital-intensive than investments in gas-fired facilities. Another factor that needs to be considered is the environmental costs of each option.

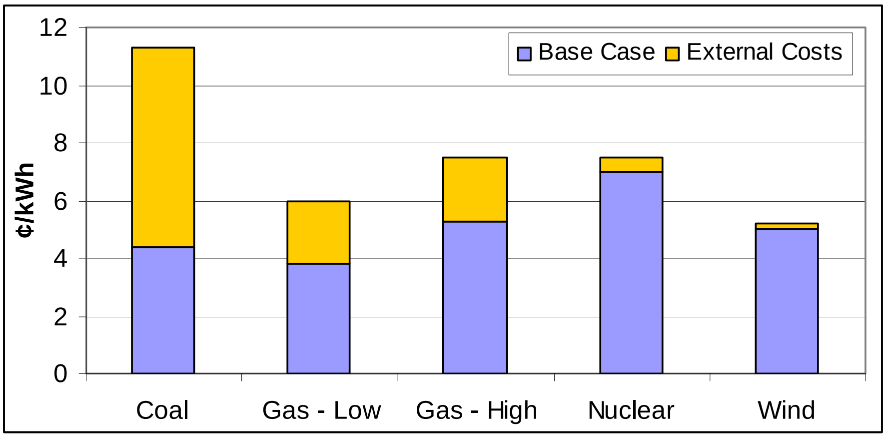
[22] *Ibid.*

4.5 The Environmental Premium of Natural Gas

The burning of fossil fuels to generate power can have a substantial impact on the environment, although natural gas burns much cleaner than coal and thus produces pollutants in much smaller quantities than coal. The impurities emitted during the combustion process include such pollutants as sulfur dioxide, nitrogen oxide, mercury and particulate matter among others. Conventional power plant emissions can contribute to phenomena like acid rain, water pollution, smog and global warming. All of these things represent a cost to society through their negative impact on human health, agriculture, and the lifespan of buildings and equipment. Therefore, different types of power generation need to be analyzed not only on the basis of their direct costs, but also on the basis of other costs that are less immediately obvious.

The European Commission has sponsored a project to quantify the costs of environmental pollution from power plants so that the overall cost of generation for different fuel types can be compared. The project, called the Externalities of Energy[23] (ExternE), has reviewed the impact and cost of pollution for power generation technologies across Europe. By adding the external costs of generation calculated by ExternE to the base case costs given in the MIT and IEA reports, a comparison of the overall costs of generation can be made inclusive of the environmental impact of each fuel type.

Exhibit 4.8: Overall Costs of Power Generation[24]



Wind energy's impact on the environment is minimal and stems mostly from activities during construction. However, the base case cost assumption of five cents per kilowatt-hour assumes optimal conditions for wind generation. Many regions in APEC do not possess these optimal conditions, making wind power an

[23] http://www.externe.info

[24] The external cost data provided in this chart are averages taken from a wide range of data made available by ExternE on its web site. The calculations made by ExternE are very site-specific. For example, coal-fired plants using different technologies and in different geographical regions have different emission profiles. For the full ranges of external costs, see the table in Appendix 3 or visit http://www.externe.info.
External costs were converted from Euro cents to U.S. cents using an exchange rate of $1.21/€.

unavailable option. Nuclear power also has a reduced impact on the environment. However, issues with technology, safety, proper disposal of nuclear waste and prevention of proliferation make nuclear power a controversial option for many APEC economies. Thus the choice of generation options often comes down to a decision between coal and natural gas. Taking the data from the European Commission's project into account, a case can be made for natural gas as the fuel of choice in economies which recognize and value the premium, even at relatively high gas prices and higher direct costs, given its reduced environmental impact and lower associated external costs.

4.6 Summary and Conclusions

Recent increases in natural gas prices may make some APEC economies hesitant to embrace natural gas as the best fuel choice to supply their economies' future energy needs. However, coal prices have also experienced periods of sharp appreciation. Increased demand combined with supply bottlenecks may contribute to higher coal prices in the future as well. Generation technologies using nuclear or renewable energy are not subject to the volatility of underlying commodity prices; however these options are often unavailable in many regions of APEC, leaving many policymakers with a choice between coal and natural gas. Although gas-fired generation presents lower upfront capital costs, in the face of today's high natural gas prices, coal-fired power appears to be advantaged from a cost perspective. However, if the overall benefit to society from the reduced environmental impact of natural gas-fired power is considered and quantified, natural gas may be the more compelling option.

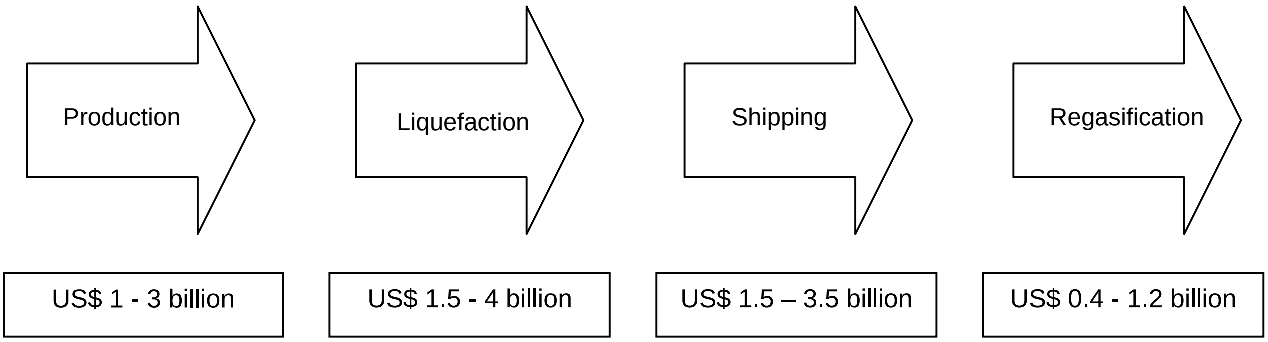
5 REVIEW OF THE EVOLUTION OF THE GLOBAL LNG MARKET

5.1 The LNG Chain – Production, Liquefaction, Shipping and Regasification

Natural gas that is found far from major demand centers is often uneconomical to transport via pipeline. One transport solution is to cool the gas to about -260º F where it is transformed into a liquid form called liquefied natural gas (LNG). In its liquid state natural gas is one-six hundredth the volume of its gaseous form, making it economical to transport, using specially constructed ships, to major natural gas markets. Once the LNG arrives at its destination, import terminals return it to its gaseous state and it is sold into the existing natural gas distribution system. This process — production, liquefaction, shipping and regasification — makes up the LNG value chain.

The LNG value chain is extremely capital-intensive. Exhibit 5.1 below shows, for projects ranging from 3 to 6 mtpa, the approximate investment needed for each portion of the chain.

Exhibit 5.1: Capital Expenditure across the LNG Value Chain



Upstream exploration, development and production of natural gas for LNG purposes differs little from the procedures of a conventional pipeline project, however the nature of the reserves is an important consideration. First, the reserves must be large enough to sustain production levels for approximately twenty years, which is generally the minimum time needed to make an LNG project worth the investment. A single train, 3.4 mtpa, plant requires 85 to 115 billion cubic meters of proven natural gas reserves. The gas must also be economical to produce and transport to a suitable liquefaction site.

Liquefaction makes up the most costly portion of the LNG value chain. Extensive design and engineering demands, transporting expensive materials and skilled labor to remote areas that have little or no existing infrastructure and operating in politically unstable environments are just some of the challenges that make developing a liquefaction facility difficult. Because of such challenges and the enormous resources needed to overcome them, these projects are generally only undertaken by international oil companies in conjunction with the specific country's state oil firm. Financing is provided by a consortium of international and regional banks and international financial institutions, often on a limited-recourse, or project finance, basis.

LNG shipping is also a critical part of the value chain. These distinctive ships must be specially constructed; they cannot be converted from a conventional tanker or other vessel type. LNG ships are either owned by an LNG producer or buyer, or they are time-chartered from an LNG shipping company. Ownership of the vessels may provide some degree of control over cargo delivery, especially for spot cargoes; however with the current cost of an LNG vessel between $160 and $230 million and a liquefaction project requiring a number of ships outright ownership of an entire fleet is expensive. A large portion of LNG ship capacity is contracted through time-charting. Under a time-charter agreement, either the buyer or seller of the LNG, depending on which party is contractually responsible for shipping arrangements, will contract with a ship's owner for rights to the ship for a specified period.

The final part of the LNG chain is regasification, where the LNG is offloaded from a ship to an import terminal, regasified, and then piped into the domestic distribution system. Regasification is one area where technology is increasing the number of options beyond conventional import terminals available to potential importers. Some of these options include Floating Storage and Regas Units (FSRUs) — LNG tankers that can also regasify their cargo — and floating buoy regasification technology where the regas apparatus latches onto the side of an LNG ship and floats with the ship while the cargo is regasified. These technologies may provide less expensive import infrastructure that can be tailored to the needs of smaller individual markets.

The commercial structure of regasification terminals can take a variety of forms. One example is a tolling model, where an independent developer builds a terminal and charges a fee for processing the LNG. By entering into a long-term contract with a company that controls either supply of or demand for LNG, the company can guarantee a reliable revenue stream that can be used to secure financing for the terminal. In China, regasification is controlled by a state oil company and is part of a domestic strategy to increase the role of natural gas in the domestic energy mix. In Japan, the vast majority of LNG terminals are controlled by domestic utilities. These utilities also take on the responsibility of contracting for LNG supply, arranging shipping, and selling the gas to domestic customers. The Japanese model, where a single entity is responsible for more than one component of the value chain, is an example of integration.

Some of the international oil companies are also engaging in this integrated model. A prime example is the Qatargas II project, where ExxonMobil and Qatar Petroleum control upstream production and liquefaction in Qatar, shipping from Qatar to the United Kingdom, and regasification and gas sales to the U.K. market. Integration is one solution to the problem of synchronizing the individual components of the

LNG value chain. Each component's development is a complex process requiring long lead times and huge investments. In addition, each component is reliant on the successful establishment and operation of all of the other components of the value chain for the delivery of natural gas from its stranded deposits to the demand centers that need it. Integration gives control of each component, allowing better coordination across the value chain and a greater ability to manage risks throughout the chain. However, integration requires enormous resources; Qatargas II was a $9.3 billion project. By using long-term gas sales contracts to reduce as much uncertainty as possible, companies can estimate the cash flow their individual projects will generate and use these projections to obtain the financing that will enable the construction and commissioning of the project.

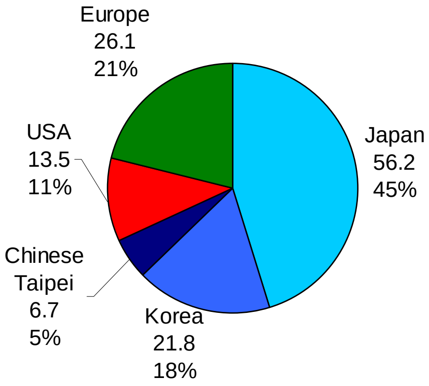
5.2 Historical and Projected LNG Supply and Demand

Because of the large costs associated with the development of LNG facilities, much attention is paid to the overall supply and demand picture for LNG. Historically, the demand for LNG centered on Asia, particularly the economies of Japan, Korea and Chinese Taipei. These economies have driven much of the growth in the region and have done so without the benefit of substantial domestic natural resources, including natural gas. Almost all of the natural gas used by these economies for residential consumption, industrial consumption and power generation has been imported in the form of LNG.

Although the U.S. and Europe historically have not imported as much LNG as the Asian economies mentioned above, their markets are growing rapidly. In the U.S., the energy crisis of the 1970's led to the construction of four import terminals. Several of these were later mothballed due to LNG's lack of competitiveness versus domestic production and pipeline imports. In recent years however, domestic gas production has reached a plateau and even begun a slight decline. In the meantime demand for natural gas has risen, fueled in part by a strong economy and greater reliance on gas-fired power generation. As of 2003, all four of the original U.S. import terminals were in operation. Since then, several of these terminals have filed for expansion, construction has begun on several new terminals, and plans for many more are in various stages of development.

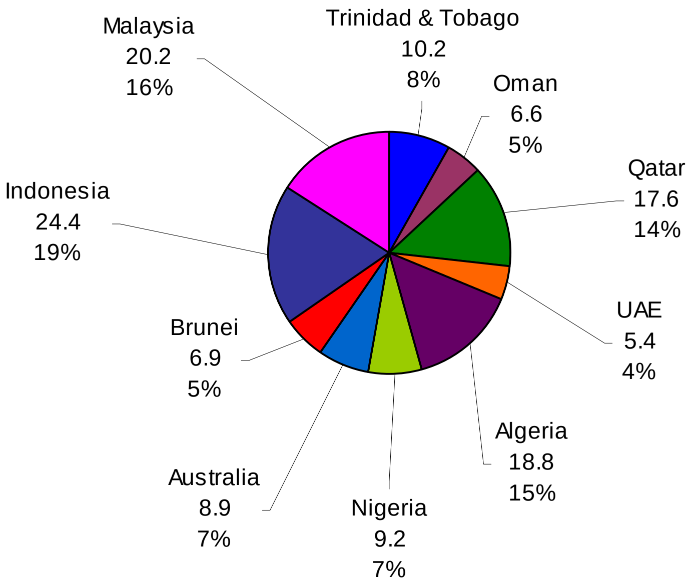
Europe's LNG demand growth has been relatively more stable. Production in areas such as the North Sea combined with pipeline imports from Algeria and Russia allowed demand to be met without extreme reliance on LNG. However, LNG has been an important source of marginal supply since the 1970's and demand has grown with the increased dependence on gas for power generation. The chart below shows the 2004 breakdown of LNG imports by region.

Exhibit 5.2: LNG Imports by Region (2004, in mtpa)[25]



The demand for LNG has driven the development of supply. Although, one of the first LNG exporters was the U.S., sending LNG to Japan from the Kenai plant in Alaska, North America never developed as a strong source of supply. Instead the Asian importers drew from reserves closer to home, and European buyers followed suit. Thus, in 2004 Indonesia was the world's largest exporter of LNG, followed by Malaysia. Algeria placed third and was the largest supplier to Europe. Qatar is a relatively new supplier of LNG, having started its first export train at the end of 1996, but has expanded aggressively. Trinidad & Tobago rounds out the top five suppliers. The Caribbean nation sends the vast majority of its supplies to the United States.

Exhibit 5.3: Major LNG Exports by Region (2004, in mtpa)[26]



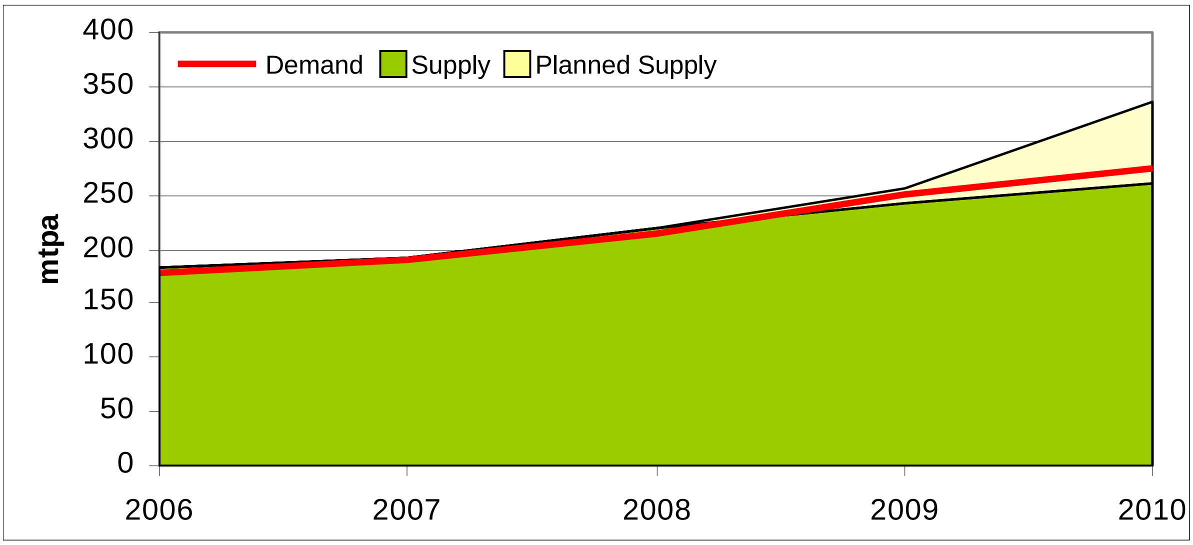
[25] BP World Energy Statistical Review 2004

[26] *Ibid*

The pattern of future supply and demand is expected to look significantly different from what is observed today. The three current Asian importers will continue to be major consumers of LNG; however their proportion of overall global demand will shrink. In contrast, an emphasis on gas-fired power generation in the U.S. and Europe is expected to increase the importance of natural gas within the overall energy mix in these regions. This trend, combined with flattening or even decreasing amounts of domestic production, will increase the demand for LNG substantially in these areas. Another new driver of demand will be emerging economies, led by China and India, both of whom are both expected to partially replace their coal usage with natural gas in an effort to increase energy security, diversity, and efficiency and reduce somewhat the harmful environmental impact of rapid economic development. However, one issue is the current high price of natural gas relative to coal. It remains to be seen what effect current prices will have on demand in developing economies. One scenario that is sometimes discussed is that of “demand destruction.” This refers to a situation in which the high price of natural gas increases the preference for substitutes such as coal, which in turn leads to reduced demand for gas and LNG imports. It may be the case that without government policies such as a pollution tax that help to monetize some of the environmental and efficiency gains of natural gas usage, gas will have difficulty competing with coal.

A shift is occurring not only in the demand picture, but also in the outlook on supply. Indonesia will soon cease to be the world’s leading LNG exporter as depleted reserves and continued strong domestic demand, encouraged in part by government price supports, reduce the amount of gas available for export. While supply from Indonesia is falling, it is rising rapidly in other areas of the world. In Asia, Australia’s export capacity is growing rapidly; by 2010 it could be exporting over 25 mtpa, more than Indonesia’s total for 2004. Qatar is taking advantage of its gas reserves, the third largest in the world behind Russia and Iran, and is positioning itself as the world leader in LNG export. By 2010 Qatar could export more than 50 mtpa, an impressive feat considering that this volume will have been developed over a span of less than fifteen years. The continent of Africa is also becoming a major player. Algeria is an established supplier and North Africa’s capacity is being further supplemented by significant development in Egypt. Greenfield projects in Equatorial Guinea and Angola will also contribute to the continent’s export totals. The most important supplier, Nigeria, could increase exports to as much as 40 mtpa by the end of the decade. The graph below depicts the expected global supply and demand picture through 2010.

Exhibit 5.4: Global LNG Supply & Demand to 2010[27]



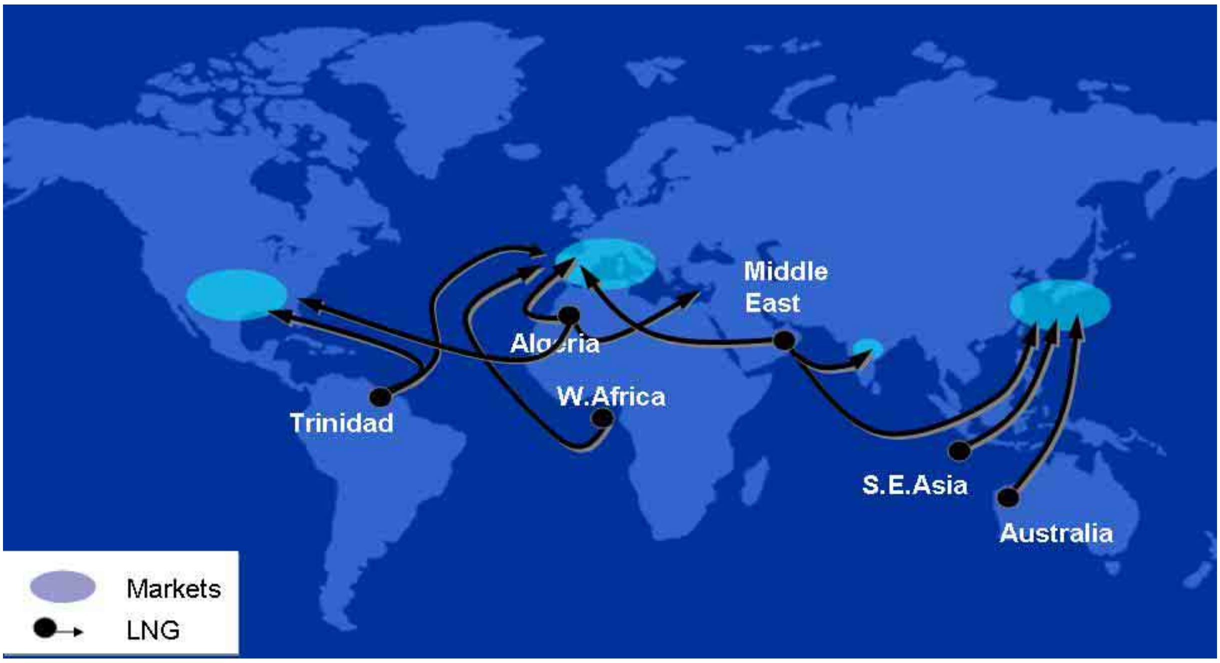
The graph shows supply will remain tight through the end of the decade. Even with the current construction schedule, supply will be tight in 2007 and 2008. Delays in construction of significant projects could even lead to shortages. However, in 2009 and 2010, projects that are currently in the developmental stage will begin to come on line and ease supply conditions somewhat, however demand growth may well outpace any gains made.

5.3 The LNG Trade

While an analysis of the global LNG market is useful, it is also important to understand that the LNG trade has historically been divided geographically into two major regions — the Atlantic Basin and the Pacific Basin — with little interlinks or overlaps. The Atlantic Basin includes (or will include) liquefaction plants in Africa, the Middle East and South America and regasification terminals in Europe and on the East and Gulf coasts of the United States and the Gulf coast of Mexico. Of more immediate concern to APEC is the Pacific Basin trade, which includes (or will include) supply plants in Australia, Southeast Asia, Russia and the Middle East and import terminals in East Asia, India and the western coasts of Mexico and the U.S. The map below depicts today's major LNG trade routes.

[27] Deutsche Bank and Taylor-DeJongh Estimates

Exhibit 5.5: Major LNG Trade Routes (2004)[28]



Traditionally, the LNG trade has been a point-to-point business. The large capital expense and significant risk of constructing an LNG liquefaction plant required that sponsors arrange long-term offtake agreements for the majority of plant capacity before construction of the plant ever began. On the buyer side, the importance of stable supply and prices combined with the lack of readily available LNG supply alternatives to provide incentive to enter into long-term contracts called Sales & Purchase Agreements (SPAs). These agreements have generally been between twenty and twenty-five years in length and include take-or-pay clauses that require the buyer to pay for quantities of LNG even if the buyer does not lift the contracted quantities from the plant. Destination clauses also limited buyer flexibility in re-routing cargos to regasification terminals not originally specified in the SPA. This traditional form of LNG trade is sometimes referred to as the "tramline model".

Sellers maintain that SPAs are necessary to obtain financing for their liquefaction projects. Many of these projects utilize limited-recourse, or project, financing where the lender has limited recourse to a sponsor's balance sheet in the case of default. Repayment of debt is therefore fully dependent on the cash flows of the project. Thus, lenders prefer ironclad contracts that reduce as much uncertainty as possible regarding a project's future cash flows. It is also important that a potential LNG offtaker be creditworthy with a strong investment-grade rating that reduces counterparty credit risk.

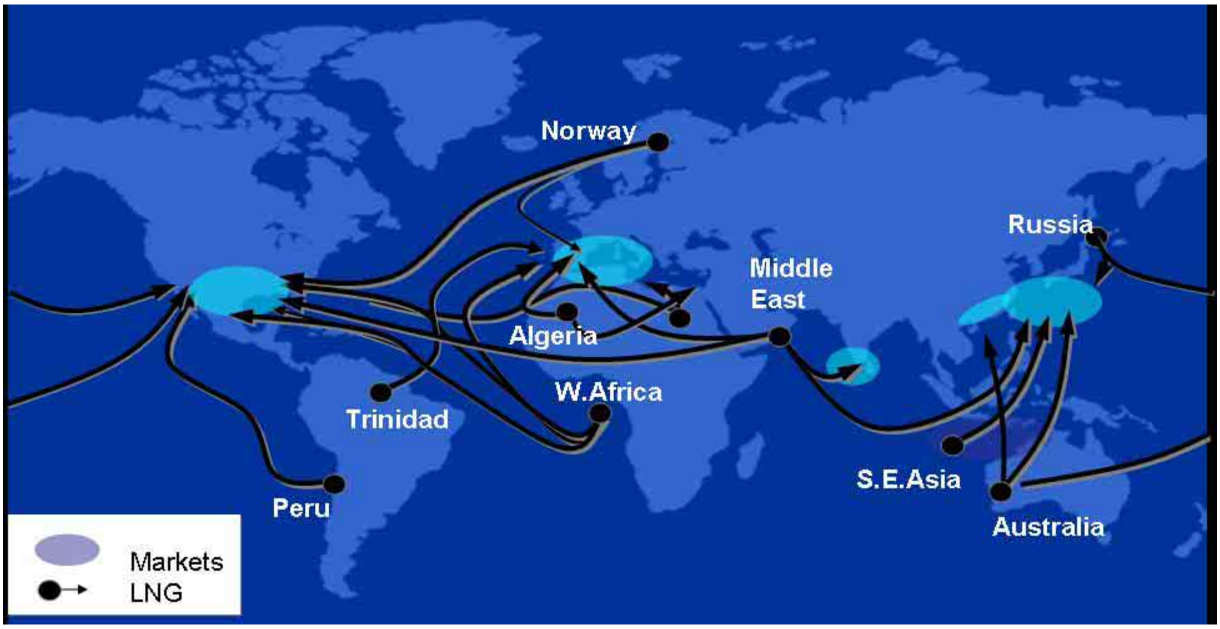
[28] Source: BG

In recent years, however, there have been some growing trends that point towards the development of a more flexible trade. As the size and volume of the market has expanded, so has its liquidity. One sign of this is the development and growth of a spot market for LNG. The spot market is a result of a number of factors. Improved design and de-bottlenecking have allowed liquefaction plants to produce above their nameplate capacities, land a few long-term SPAs, such as the one for the Dahbol power plant in India, have collapsed. Both of these factors have led to excess supply not accounted for by long-term offtake contracts. The availability of second hand ships, with extended operating lives, as well as some overbuild in the shipping industry has also provided the excess shipping capacity necessary to transport spot cargoes. Finally, growing demand for gas, especially peak seasonal cargos has provided a market for short term and spot deliveries.

Another trend has been the development of an arbitrage or swap trade, especially in the Atlantic Basin. Firms have realized that by holding regasification capacity in two markets, such as the U.S. Gulf coast and Spain, they can divert cargoes to whichever market is currently exhibiting the higher price for natural gas and thus maximize the value of their supply.

These developments have led to calls on the part of buyers for greater flexibility in SPAs and there are signs that this is occurring. Contract lengths have dropped into the fifteen-to-twenty year range and a growing proportion of contracts are of an even shorter nature. Destination clauses have also become less commonplace, which has increased the importance of control over shipping. As more liquefaction plants have come on line, price competition has grown. This has led buyers to request greater pricing flexibility, include price re-openers every several years. Much of this has been predicated on the fact that as the LNG trade has matured, sponsors and lenders have become more comfortable with calculated exposures to volume and price risks. One example is the Northwest Shelf project in Australia, where a decision to proceed with a fifth train was made without a full complement of SPAs in place. The sponsors based the decision based on a broader evaluation of the market, including the United States as a volume taker, as opposed to specific commitments. As the market for LNG continues to deepen, flexibility will continue to increase. The map below shows the outlook for the LNG trade in 2010.

Exhibit 5.6: Major LNG Trade Routes (Expected in 2010)[29]



5.4 LNG Pricing

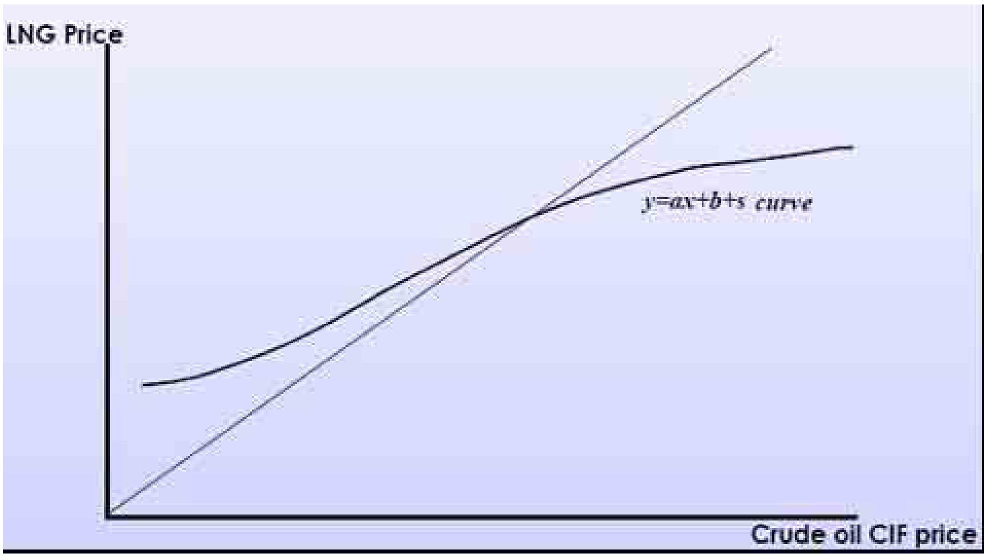
The point-to-point nature of the LNG trade originally created two fairly isolated markets; the Pacific and Atlantic — this has now expanded to include markets for China, India and the U.S. Accordingly, each market developed its on unique pricing model that was linked to a regional index of oil or natural gas prices. The Pacific model, known more commonly as the Japanese model, originally was heavily linked to the Japanese Customs Clearing (JCC) price of crude oil, also known as the Japanese Crude-oil Cocktail. Pricing followed the following formula;

$$P_{LNG} = a \times P_{JCC} + b$$

where *a* was a number between zero and one that indicated the strength of the linkage to the JCC and *b* was a fixed component that served as a price floor. By the mid-eighties, this model had evolved to include different values for the variables *a* and *b* for different price ranges of the JCC index. The overall effect is to support sellers when oil prices are low and support buyers when oil prices are high. This formula is referred to as the "s-curve" and is depicted in the chart below.

29 Source: BG

Exhibit 5.7: The S-Curve[30]



The Atlantic pricing model is in reality several pricing models. Depending on the region and the individual contract, the pricing linkages will vary. Prices may be linked to a basket of oil products; mainly fuel oil and gas oil with a heavier weight often being placed on fuel oil. Other contracts link the price of LNG directly to crude oil using the Brent index. The LNG price generally lags the index price because prices are recalculated on a quarterly basis using a price average from the preceding three to six months of data. In the U.K., which just recently began to import LNG after a long hiatus, prices are linked to the country's natural gas price index, the National Balancing Point (NBP). The SPA for QatarGas II was linked to the NBP price and did not contain a floor, effectively exposing the lenders to the project to U.K. price risk. This was a landmark transaction, made possible in large part by the integrated nature of the project, but also due to an increasing understanding of, and belief in, the LNG market on the part of lenders.

The underlying linkage to LNG prices in the U.S. model is the Henry Hub index. Henry Hub is a natural gas hub located in Louisiana, near the Gulf coast, and its position at the center of a confluence of interstate gas pipelines allows it to serve as the delivery point for the natural gas futures traded on the New York Mercantile Exchange (NYMEX). In some instances the U.S. pricing model is linked to the Henry Hub Index in a similar method to that seen in the Japanese s-curve model. Another common method is net-back pricing. The formula is as follows:

$$P_{\text{LNG delivered Ex-ship}} = P_{\text{Henry Hub}} - \text{Buyer's Cost} - \text{Buyer's Margin}$$

[30] Institute of Energy Economics, Japan

Buyer's costs include items such as the cost of regasification and marketing and administrative costs. In the case of FOB sales, prices can be netted back to the liquefaction plant by allowing for shipping costs.

Over the past several years there have been some new developments in pricing conventions. The first development is a trend towards price convergence across all of the markets. As the global market broadens, more and more sellers are targeting more than one market and thus competing across markets. This increasing competition has lowered the price spread across regions. Additionally, as more buyers seek to earn arbitrage profits by diverting cargoes to the regions with the highest price, they increasingly create pressure for prices to converge. It is possible that in the future gas prices will become uniform across the globe with a linkage to a single index like Henry Hub.

Another trend has been the use of a competitive tender process to solicit supply for given quantities of LNG. This method was successfully implemented by Chinese buyers for their Guangdong terminal and allowed them to secure lower prices, a different price formula, and the ability to acquire upstream resource equity, quite different from many other previous SPAs. These prices, along with reports of lower prices secured by Indian importers, led many buyers to seek price re-openers, whereby prices would be renegotiated with sellers every several years. However, many of these demands were made at a time when it appeared that there would be extra supply capacity in the future. Since that time, plans for several plants that were originally supposed to come on line in the 2007-2008 timeframe have been pushed back, tightening supply and giving the advantage back to the sellers of LNG. This could be one explanation as to why negotiations between Chinese buyers and Chevron regarding supply from the Gorgon project in Australia have faired so poorly. The conditions necessary to create a buyers market may not be seen again until the end of this decade, when the margin between available capacity and demand may widen slightly.

5.5 Drivers of Recent High Growth in the LNG Trade

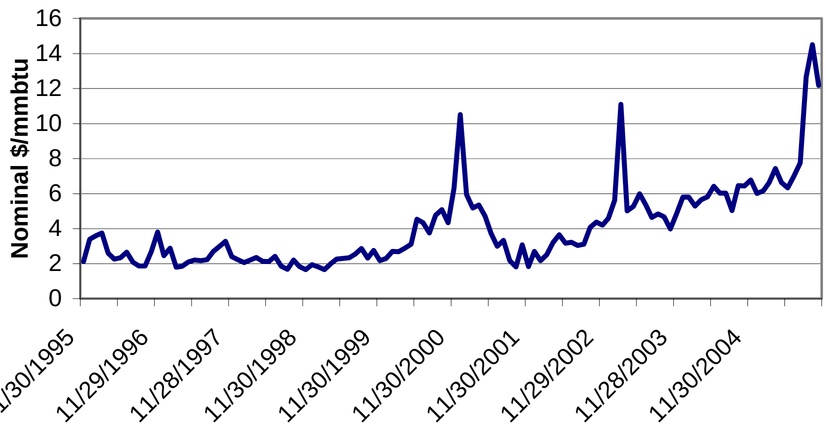
The global LNG trade has increased dramatically over the past decade and is expected to continue its strong growth in the years to come. Several factors have driven the growth in the global LNG market; including cost reductions across the value chain, high energy prices and an increasing demand for natural gas.

The Gas Technology Institute (GTI) estimates that liquefaction costs have fallen by 35% to 50% over the last ten or so years. GTI also estimates that LNG shipping costs have fallen about 45% over the last twenty years. These cost reductions have been made possible by a number of developments. On the liquefaction side, in a 2003 report on the global LNG market, the EIA points to improved operating efficiency due to technological innovations, more qualified contractors, better engineering techniques and an increasingly competitive bid process as factors that have led to lower costs. Increasing economies of scale have also played an important role in decreasing the dollar per mmbtu cost of regasified LNG. The first LNG trains had production capacities of 1-2 mtpa. Now trains with nameplate capacities of 5 mtpa are being commissioned and some of the trains currently under construction will have capacities of 7.8 mtpa. In addition, many of the new trains coming on line are expansions to existing sites as opposed to greenfield developments, thus requiring significantly lower capital and less back up equipment. Expanding at an existing site is much more economical than constructing a completely new site because some of the infrastructure at an existing site can be utilized, with minimal modifications, by the expansion train.

Economies of scale have also played a role in reducing the costs of shipping LNG and will continue to have an impact in the future. Currently, the average ship capacity is around 138,000 cubic meters, however, ships with capacities of 210,000 cubic meters are under construction and plans for even larger ships are being developed. Other significant factors that have driven shipping costs lower is the increasing number of shipyards capable of building LNG tankers and the move away from traditional steam turbine driven vessels. The EIA cites this increase in shipyard competition as the most important factor in driving down the costs of LNG ships.

Another factor behind the LNG trade's strong growth has been recent energy prices, which have been at levels not seen since the energy crises of the seventies. As Exhibit 5.8 shows, prior to 2000 U.S. gas prices averaged around $2.50/mmbtu.

Exhibit 5.8: U.S. Natural Gas Prices (1996-2005)



However, in the last several years the U.S. natural gas prices have trended upwards because of the rising price of oil and the shortage of available gas supplies, particularly during the winter periods. This trend has been seen around the world, as the high price of oil has also increased prices of substitutes like gas. These higher prices have made the economics of the LNG trade much more attractive. With prices expected to be in the $4-5/mmbtu range or higher going forward, interest in the LNG market will continue to be strong.

A final factor driving the expanding LNG trade is strong demand for natural gas. One aspect of this demand has been a growing reliance on natural gas for power generation. Environmental concerns regarding coal and the lower capital costs of gas-fired power plants have made gas a popular choice for power generation and created a large structural demand. At the same time, traditional supply for the European and American markets has reached a plateau and is beginning an incremental decline. Increasing demand and shrinking domestic supply have increased the importance of LNG's role in these markets.

5.6 GTL – An Alternative to LNG

Gas-to-Liquids (GTL) technology has existed for more than 70 years, but its development on a commercial scale has been, until recently, restricted to countries where conventional oil supplies were limited, such as Germany during World War II and South Africa during the apartheid era, or to the development of high value specialty chemicals, as in the case of the Bintulu plant in Malaysia. However, in the past decade, there has been a growing interest in the possibility of using GTL to monetize stranded gas resources. GTL not only adds value by converting low quality gas into oil, but it also yields superior-quality hydrocarbons that, once blended with regular fuels, produce lower-emission, higher quality fuels.

Currently there are three GTL plants in operation; one in Malaysia, one in South Africa, and a plant in Qatar that started operations in June 2006. The plant in Malaysia uses Shell's proprietary Middle Distillate Synthesis (SMDS) technology, while the other two plants use Sasol's Fisher-Tropsch (F-T) technology.[31] There are two broad technologies for GTL to produce a synthetic petroleum product, a direct conversion from gas, and an indirect conversion via synthesis. Sasol, Shell, ConocoPhillips, ExxonMobil, BP, Syntroleum and Rentech are some of the firms that have developed GTL technologies, all of them based on the indirect F-T synthesis. There have been several direct conversion processes developed, but none has been commercialized due to its high costs.

In addition to the three existing plants, there are also several plants under construction or in advanced planning stages. Qatar is leading the way with five projects that have a total capacity of approximately 625,000 b/d. However a moratorium on new natural gas projects that imposes a cap on gas production from Qatar's North Field may delay the implementation of some of these projects.

The renewed interest in GTL has been driven both by higher oil prices, which greatly improve project economics, and by the environmental advantages that GTL products offer. These environmental features

[31] *Natural Gas Market Review 2006 – Towards a Global Gas Market.* International Energy Agency.

command a price premium in the market, and combined with high oil prices, new legislation introduced in OECD countries demanding cleaner fuels, and advances in technology, have improved the economic attractiveness of GTL projects.

GTL projects also represent a revenue diversification opportunity for the producing country; the diesel produced by the GTL process is sold into transportation fuel markets as opposed to the more traditional natural gas markets that LNG supplies. Thus, by constructing a GTL plant an economy can diversify its gas exports across two very different markets.

Just how quickly GTL projects can be implemented will depend to a large extent on the project economics and the willingness from financial institutions to invest in GTL initiatives. APEC economies should consider GTL as an alternative method of monetizing stranded reserves of natural gas.

5.7 Summary and Conclusions

Major capital costs and the complexity of coordinating the many components of the LNG value chain have presented difficult challenges for the development of the LNG trade. Risks have been managed by creating strong contractual relationships throughout the chain that guarantee investment returns but reduce the flexibility of trade. Many projects have demonstrated that LNG can be a stable, competitive and profitable supply of energy. Cost reductions throughout the chain combined with high energy prices have further increased the competitiveness of LNG. This has encouraged growth in both supply and demand, and has resulted in a strong and increasingly liquid market.

The development of large export capacities in areas geographically able to serve several markets, such as Qatar, West Africa and Australia, have also furthered the development of a truly global market. Increased supply and shipping capacities and the increasing comfort lenders have with exposure to the risks in the LNG market have enabled more flexible sales contracts, further driving market liquidity. These factors have positioned the LNG trade to be a major supplier of the world's growing demand for natural gas.

6 ECONOMIC AND ENVIRONMENTAL CONDITIONS FOR NATURAL GAS TO BECOME A VIABLE ENERGY SOURCE

6.1 Gas Industry Infrastructure, Gas Market Creation and Expansion

Natural gas is not an easily tradable commodity. Although it can be stored underground in depleted reservoirs via re-injection, as linepack in pipelines or in either compressed or liquid forms (CNG/LNG), the extraction of natural gas from its production location, its transportation to centers of potential demand, and its distribution require it to be handled in bulk before it can be supplied to markets. This requires substantial investments to be made in production, storage, transportation, and distribution infrastructure. In addition, there must be enough reserves available to supply the infrastructure over the long period of time needed to reasonably recoup the investment in the infrastructure. This is usually a period of twenty years or more for major projects.

As has been emphasized in a previous report to the APEC Energy Working Group on cross-border natural gas trade, natural gas markets do not automatically happen — they must be created.[32] In this regard, the creation and expansion of a gas market may be hindered by:

- political and institutional barriers
- economic limits (low standards of living)
- inter-fuel competition
- the lack of gas transmission and distribution infrastructure
- the lack of investment in gas-based technology, such as CCGT power generation
- heavy-handed regulatory regimes
- deregulation (if deregulation constrains buyers from committing to long-term offtake or supply contracts or disaggregates buyers so as to reduce their financial capacity to undertake such commitments) and
- the lack of recognition of the environmental benefits and value of gas.

Market creation involves both contractual and regulatory issues. In an open market the former can be dealt with by commercial negotiations among sellers and buyers. However, in emerging markets the government may directly or indirectly be one of the parties, with a prescribed framework under which it operates. Regulatory regimes often constitute a major barrier. An "industry vision" by the government is an important starting point.

[32] ResourcesLaw International, "Great Expectations: Cross-Border Natural Gas Trade in APEC Economies", Report to the APEC Energy Working Group, APEC Secretariat, Singapore, 2004.

Solutions must be tailored according to the maturity of each individual domestic or regional market. Conditions in mature gas markets, such as Japan or Thailand (each of which are completely different in structure and operation), are to be contrasted with conditions in emerging markets, such as China or Viet Nam. If an economy already uses LPG extensively, such as in Indonesia, this can provide a foundation market of informed gas users from which customers can be progressively switched to reticulated natural gas, as is now happening in Hong Kong, China.

6.2 Economic Growth

Growth in demand for all forms of energy comes with economic growth, with energy demand typically exceeding GDP growth. In Viet Nam, for example, the use of domestic sources of natural gas is rapidly increasing following a surge in power demand resulting from the rapid industrialization and economic development of the economy. Economic growth not only underpins natural gas development, but the availability of affordable natural gas can accelerate economic growth.

There is much debate within the APEC region about which fuel is most beneficial for economic growth. Historically, economic growth in the region has been underpinned by coal and petroleum energy sources. Taking cost, efficiency, and environmental factors into account, natural gas may now be the optimal fuel for growth and economic development in many of the APEC developing economies. North America and Europe have a long history and culture of natural gas utilization for industrial, commercial and domestic use (lighting, heating and cooking), and have had the necessary infrastructure in place for many years. Asia's energy network is developing later, to supply electricity and gas demand to fuel economic growth and satisfy demands for improvements in standards of living. In Asia, air-conditioning is driving much of the domestic demand, as opposed to space heating in the colder northern hemispheres.

Economic factors such as industrial growth and increasing per capita incomes, will affect power demand and thus natural gas consumption in developing countries. Volatile oil markets will also continue to affect natural gas use due to the desire of many economies, developed and developing alike, to diversify their energy mix away from over-dependence on foreign oil sources. This will also serve to allow them to maximize foreign exchange earnings from the export of readily tradable fuels.

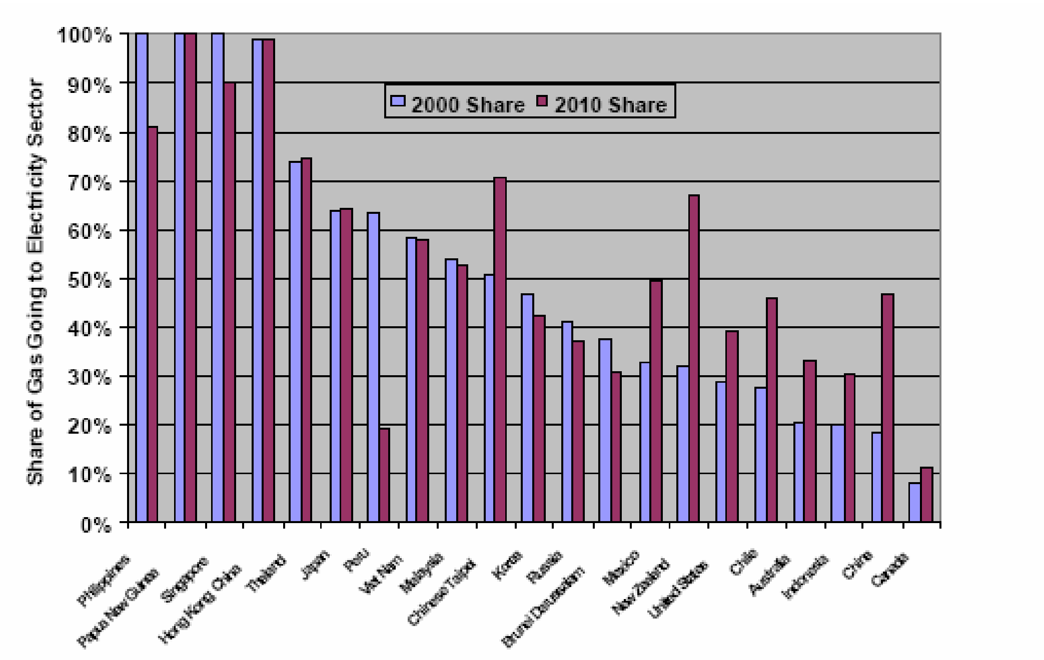
Growth in natural gas demand in the developed APEC economies remains far more moderate than in the developing economies, because much of the power generation infrastructure already exists. For example, natural gas demand in both North America and Japan is projected to average only 1.5% growth annually through 2025. In contrast, China's consumption is projected to grow at a rate of 7.8% annually; Korea is expecting average growth of 3.7%; other emerging Asian economies anticipate average growth of 2.9% per year; and Latin America's consumption figures will go up by an average of 3.3% annually, all through 2025.

Focusing specifically on the industrial sector, developing economies will see a more dramatic annual increase in utilization over developed economies: annual consumption in Japan's industrial sector will go up by an average of 3.4%, while that of Korea is expected to increase by an average of 7%.[33]

6.3 Growth in the Electricity and Petrochemical Sectors

The main driver of natural gas in most APEC economies is the electric power sector. The graph below illustrates estimated trends in natural gas consumption growth between 2000 and 2010. Of the 21 economies listed, 11 experience an increase in the share their electric power sectors hold in gas demand and two experience no change, including Papua New Guinea, whose electric power sector share is already at 100%. Subject to the availability of economic and socially acceptable supply, the electric power sector's share of gas demand in China and New Zealand is projected to more than double between 2000 and 2010.

Exhibit 6.1: Electric Power Sector Share of Gas Demand in APEC Economies[34]



Source: APERC (2002a)

The petrochemical industry is the second largest user of natural gas, and specifically accounts for most of the increased natural gas imports of Singapore. The petrochemical industry also accounts for a part of the U.S. natural gas imports, even though power generation continues to dominate natural gas end usages.

[33] EIA International Energy Outlook - 2005, p. 40, 42-45

[34] Natural Gas Market Reform in the APEC Region – 2003 (APERC), p. 33, Figure 18

6.4 Environmental Factors

Environmental constraints, such as the Kyoto protocol and national legislation, are expected to be additional drivers for natural gas demand. Natural gas is seen as a clean, efficient, and reliable energy source. In many countries maturing oil- and coal-fired power plants are set to be replaced by new, natural gas-fired power plants currently under construction. Oil and coal power plants emit higher levels of carbon emissions and are increasingly considered as environmentally unattractive from an emissions perspective — coal plants also have issues with regard to ash disposal. Carbon emissions should be accounted for and, subject to local policy, priced in to all new projects and investments.

The practice of CO_2 venting can reduce to some extent the environmental advantage natural gas holds over other hydrocarbon-based fuels. Natural gas is primarily composed of methane, but may also contain ethane, propane and heavier hydrocarbons with small quantities of nitrogen, oxygen, CO_2, sulfur compounds and water. Natural gas processing plants remove the acid gas components from the natural gas through a process called gas sweetening, allowing the gas to meet acid content limitations for final products. The CO_2 emissions, once separated, are generally vented into the atmosphere since there are little economic incentives to do otherwise.

However, the oil industry has found an alternative to simply venting the CO_2. The process is known as CO_2 Capture and Storage (CCS), and consists of the compression of separated CO_2, transportation of the compressed CO_2 through pipelines, and injection of the CO_2 into secure aquifers or abandoned oil and gas reservoirs where it is stored. To date there are only three projects that capture the CO_2 separated from the natural gas and injected underground. The best known project is Sleipner, which is operated commercially by Statoil, where CO_2 is separated from commercially produced hydrocarbons and injected into an aquifer 1000 m below sea level at 1 million tonnes per year. Several additional storage projects are under development in Argentina, Australia, Austria, China, Germany, Japan, Poland and Indonesia.
Another use for the captured CO_2 is Enhanced Oil Recovery (EOR) in which CO_2 is pumped into existing oil fields. This practice improves oil yields and total amount of oil recovered while leaving the CO_2 trapped behind. More than 70 such projects exist worldwide.

Other benefits of this practice include: secondary revenue stream as captured and stored CO_2 can be converted into a tradable commodity and enhanced air quality as these processes tend to remove other potentially harmful pollutants. While some challenges still exist (e.g. cost of the process is still relatively high, potential for leakage unknown), it is technically feasible now and the global opportunity is considerable (> 1000 gigatonnes of CO_2). According to the IEA the cost of capturing and storing CO_2 ranges from $50 to $100 per ton. With appropriate R&D investments the IEA estimates that cost can be brought down to $25-$50 per ton; but even with cost reductions, policy incentives are still necessary to stimulate the market to adopt CCS technologies.[35]

6.5 Inter-Fuel Competition

To be a viable energy source, the price of natural gas must be competitive compared to the other energy sources (oil, coal, renewables, and hydro) in the application it is being used for. Ideally, natural gas should be produced domestically from easily accessible sources or else imported at a competitive price under contract terms which match the needs, energy security, deliverability and specifications required by the end user. Developing natural gas resources can be more challenging to finance than crude oil or coal projects because natural gas is typically locked into a single destination market, more difficult to transport, has significantly higher threshold volumes of throughput to be economically viable and requires the development of more complicated infrastructure. The developing APEC economies in both Latin America and Asia have had greater difficulty in attracting the necessary investment and securing the long term supplies of gas, and as a result have been more reliant on oil and, to a certain extent, coal, for energy production. In addition, many investors and project sponsors prefer investing in oil development projects because oil is easier to sell and there is a quicker return on investment.

For many APEC economies, coal has always been a more cost-effective option than natural gas and is abundantly available locally. For economies like China, which have access to large amounts of coal and growing demand for energy in general, future volatility in natural gas prices would allow coal to remain an appealing alternative for some of its supplies, where the quality is adequate and efficient/cost effective transport can actually get the coal to the energy markets. Advances in clean-burning coal technology, given the volumes of coal which exist and the demand for energy which will require its use to meet demand, are likely to increase the use, life and environmental appeal of coal as an energy option.

The availability of coal as a competing fuel source may continue to be a major inhibiter of natural gas consumption in the long-term. The power generation sector is expected to consume 45% of worldwide natural gas supply in 2020 and to consume 69% of worldwide coal supply. If constraints on natural gas supply are not eased, gas prices can be expected to rise, in turn slowing consumption.

6.6 The Infrastructure Gap

Overall, barriers to natural gas utilization hinge upon a lack of related infrastructure, including LNG receiving terminals and pipelines, both for long-distance transport and local distribution. This is an area where rapid expansion of existing systems in developed APEC economies, such as the United States or Canada, is required, but developing APEC economies also need to start or continue to bridge the infrastructure gap. In Asia the most developed areas have higher levels of overall energy consumption,

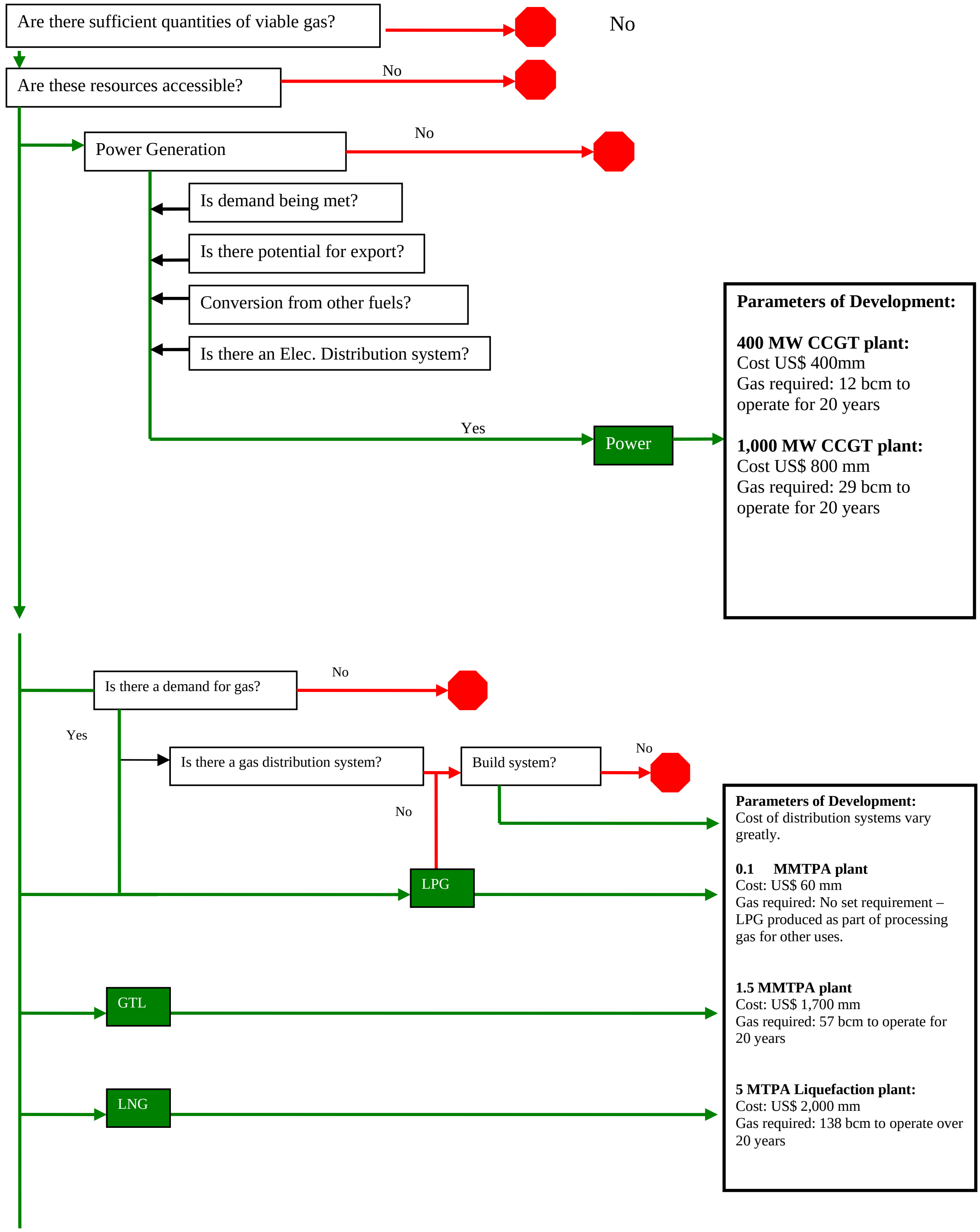
[35] Prospects for CO_2 Capture and Storage (CCS) – Fact Sheet. International Energy Agency. 2005

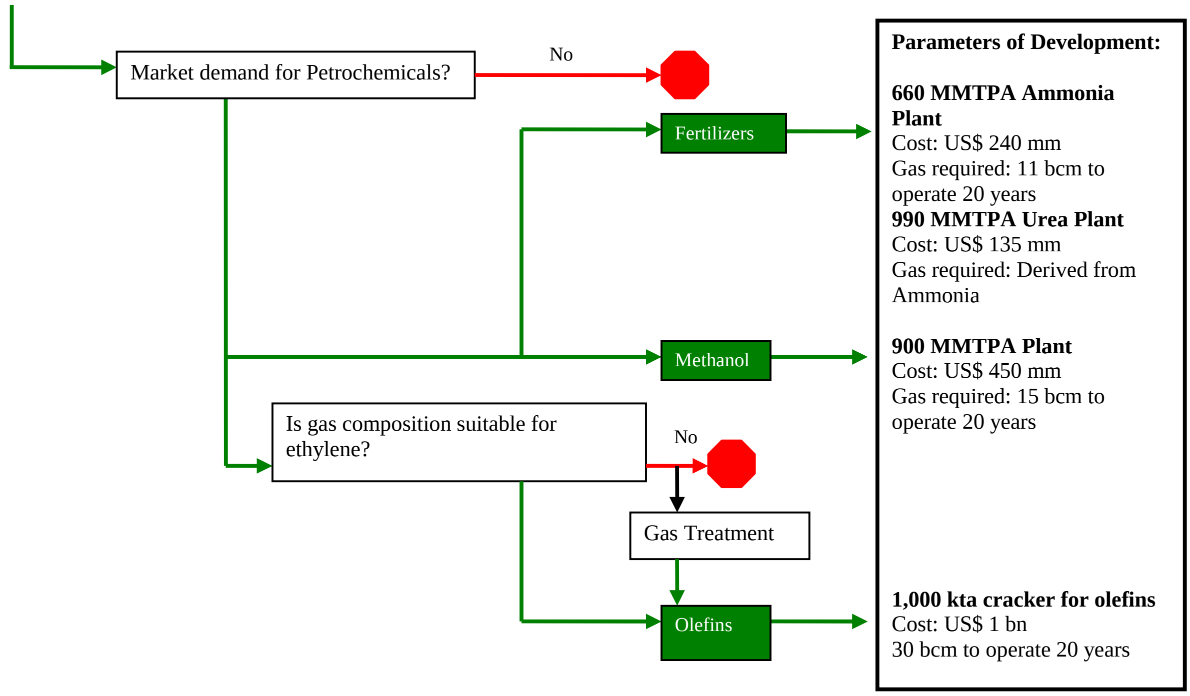
but are also often the farthest removed from natural gas resources. Investment in infrastructure and transportation networks will be imperative in promoting natural gas use among APEC member economies in Asia.

Japan, Korea, and Chinese Taipei, the three most developed economies in the Asian region, were until 2006 the only importers of LNG. The first shipments to China started in 2006. The distance of these importing economies from reserves in Australia, Brunei Darussalam, Indonesia, and Malaysia has made LNG the most efficient means of trading natural gas between these economies. However, a lack of related LNG or import pipeline infrastructure in many APEC economies will continue to retard natural gas consumption.

Developing the natural gas sector requires very large investments. These investments can be private, in which case a favorable investment environment is required, or public, where a strong commitment from the government or multilateral agency is a prerequisite. In any case, a defined base load demand to underpin the investment, preferably coupled with expected strong growth in demand to provide the investors with upside opportunity, should be present to justify investments in the natural gas sector, and also to help fund them. Natural gas projects are very costly to finance. In the case of private projects, they can be developed by large international oil companies, which have the necessary resources to either invest equity or project finance from international capital markets. In the case of public projects, states must have a good credit rating to be able to borrow the large amounts of money necessary to finance their share of these projects. Public private partnerships have become increasingly common to structure large infrastructure projects and combine private capital with government guarantees.

The decision tree presented below covers the principal options open to a government or energy company when considering how to monetize gas effectively. These basic options, as seen in the diagram, include direct utilization for heating and cooking, generation of power, petrochemicals, LNG, LPG, and GTL. Each of these possible uses of gas requires a minimum available quantity to be viable. The chart lays out the parameters for each gas monetization solution including an estimate for the required capital investment and the amount of gas needed as feedstock for 20 years. This time period is necessary as the minimum number of years required to recover the investment made in the infrastructure and to account for the assets' depreciation.


Are there sufficient quantities of viable gas?
No
Are these resources accessible?
No
Power Generation
No
Is demand being met?
Is there potential for export?
Conversion from other fuels?
Is there an Elec. Distribution system?
Yes
Power
Parameters of Development:
400 MW CCGT plant:
Cost US$ 400mm
Gas required: 12 bcm to operate for 20 years
1,000 MW CCGT plant:
Cost US$ 800 mm
Gas required: 29 bcm to operate for 20 years
Is there a demand for gas?
No
Yes
Is there a gas distribution system?
Build system?
No
No
LPG
GTL
LNG
Parameters of Development:
Cost of distribution systems vary greatly.
0.1 MMTPA plant
Cost: US$ 60 mm
Gas required: No set requirement – LPG produced as part of processing gas for other uses.
1.5 MMTPA plant
Cost: US$ 1,700 mm
Gas required: 57 bcm to operate for 20 years
5 MTPA Liquefaction plant:
Cost: US$ 2,000 mm
Gas required: 138 bcm to operate over 20 years



What the chart does not highlight is the additional costs associated with each of these options that will also need to be taken into consideration.

- In all cases the location of the proposed plant needs to be evaluated carefully. A plant will most likely be built either close to a gas source or to a client market. This may also require the infrastructure either to get the gas to the plant or the end product to the client.
- In all cases an appropriate regulatory and financial market system needs to be in place to ensure that the needed investments can be encouraged. An unfriendly regulatory or investment market can cause considerable barriers to the successful development of gas-related projects.

Each gas monetization option also has associated with it specific processes, and therefore costs, which may need to be considered depending on the quality and content of the gas, as well as its location and disbursement.

Gas Gathering: In the case of gas being produced from smaller, more disbursed fields, it may be necessary to develop a gas gathering system.

Associated Gas: Frequently, associated gas is either flared or pumped back into an oil field to improve oil well lifting. Any decision to utilize this gas for other uses will need to take into consideration the costs associated with less efficient oil production or alternatives to ensure production levels can be maintained.

Power Generation: When developers or governments are considering utilizing gas for power generation, it is fundamental to consider whether there is a domestic gas market and if the electricity can be delivered to customers. If the transmission and distribution system needs to be developed, there are other issues and costs to be considered beyond the sufficient supply of gas. It is also necessary to consider if the likely customers, both households and industries, have a strong tradition of payment for services. In addition, in many emerging markets theft of electricity and non payment can undermine the viability of these types of projects. The possibility of electricity export should also be considered.

Gas Distribution for Domestic Utilization: Like power generation and electricity distribution, the need for market development and the ability of customers to pay for the gas also have to be considered before developing a domestic in-home gas distribution system. In many economies, there is little or no tradition of using gas for either cooking or heating and therefore, the added cost of developing a domestic gas infrastructure system might be cost prohibitive. Alternatively, a more appropriate solution might be LPG, which can be bottled and more easily transported even to remote regions.

LNG: As a gas monetization option, LNG has been widely discussed in recent years, but it remains a costly alternative for gas monetization. In addition, other prohibitive costs may be possible gas gathering and gas treatment requirements. However, there is an increasing demand for LNG from many of the principal energy markets and gas consumers of the world (the European Union, Japan, the United States).

GTL: Though the technology has existed for nearly 60 years to convert coal to liquids, it has been not yet been applied to natural gas feedstock. This is changing with several projects being developed in Nigeria and Qatar. For example, Qatar and South Africa's Sasol recently inaugurated the Oryx gas-to-liquids (GTL) plant, the first of several projects planned by Qatar at it seeks to become the world's biggest GTL producer. The plant's full capacity is 34,000 barrels per day (bpd) including 24,000 b/d of diesel and 8,000 b/d of naphtha. As with LNG the additional potential costs, other than the capital required to build the plant itself, may also include developing the gas gathering and distribution system.

Petrochemicals: The development of a petrochemicals industry generally requires a greater commitment on the part of the host country government and the developers. The quality and content of the gas also needs to be assessed to decide which of the possible processes are suitable. Fertilizer and methanol development are two of the more obvious and less complicated options for downstream petrochemicals, as they require less treatment of the gas than ethylene and olefins. However, should the gas be unsuitable it may need to be treated for acidity, CO_2, water or stripping to separate the gas from the methane, ethane, and propane. Each of these procedures would require significant additional costs.

6.7 Political and Institutional Barriers

In Latin America, although the infrastructure gap is the primary barrier to increased utilization of natural gas, there are numerous plans for the expansion of existing infrastructure, as well as the construction of both new LNG terminals and transnational gas pipeline networks. There is also an overarching goal of regional energy sector integration and security.

Despite many of these advances and forward-looking policies, however, many political and institutional barriers remain to the increased use of natural gas in the Latin American members of APEC. Although the Andes mountain range serves as a physical impediment to infrastructure expansion in the northern and central regions of South America, there are other barriers that range from a lack of popular support for projects involving the extractive industry, to the long-standing animosity between Bolivia (which holds the second largest reserves base in the region) and Chile, to which Bolivia's only access to the ocean was ceded in the War of the Pacific in 1883; and institutional constraints concerning local financial markets, available capital and/or credit in the region, and legal frameworks to support the necessary commercial agreements and contracts.

Many similar institutional barriers to development are also prevalent in the developing APEC economies in Asia.

6.8 Structural and Regulatory Reform of the Gas Market

Structural and regulatory reform to attract investment to develop the necessary infrastructure will be necessary to increase natural gas use in developing APEC economies.

Gas market reforms should aim for increased competition and greater efficiency, which should generate lower prices. For gas importing economies, lower prices would result in increased demand and the associated economic benefits of increased gas usage, such as greater industrial output. For exporting economies, increased efficiency would support lower costs of production, and lower prices would translate into increased consumer demand. However, in the case of investments in capital-intensive infrastructure, some allowances may need to protect investors from competition for a period of time to ensure that the investors earn an adequate return on their investment. Without this protection, private investment in natural gas infrastructure may be discouraged.

Potential reforms of the natural gas market should include:

- market liberalization, allowing private investors access to the market
- directives mandating access to facilities (pipelines, terminals, storage, etc.) by third-parties
- preferential tax treatment for nationally important natural gas projects and
- environmental policies, encouraging greater use of natural gas.

Chapter 9 provides a more in depth discussion of policies favorable to the development of natural gas markets.

More competitive pricing mechanisms with greater transparency will be necessary to increase natural gas utilization across the APEC economies. If governments are too heavy-handed in the regulation of natural gas prices (for instance by subsidizing domestic gas prices), this will distort consumption patterns and will deter investment in exploration and production of natural gas and in gas-related infrastructure.

6.9 Technology

Several technologies are available to developing APEC economies that could help them increase their natural gas usage. The use of LPG and LPG air to create a gas market, then converting users to reticulation, are available technologies. Encouraging the use of LPG, as a transition fuel, may have merit, in particular when it can be also used as a transport fuel and for the establishment of LPG-air systems.

Compressed natural gas (CNG) – offers the possibility of lower capital cost entry and smaller volumes that can be moved around, but comes with a penalty of being a lower density fuel. CNG may be an appropriate technology solution when cheap local gas is available and transport distances are short.

Coal seam methane (CSM) – the APEC economies have considerable untapped potential, but small market players and technology suppliers, a checkered history of success, and poor or no regulatory frameworks in many economies are current barriers to either starting or increased development.

Liquefied natural gas (LNG) – for the developing APEC economies, bigger projects, such as LNG facilities, may not always be better for encouraging the development of gas markets, as some markets lack the critical size.

New and alternative energy conversion technologies are also available:

- ➢ Dual firing – power generation using dual fuels (one being natural gas) to lower the greenhouse footprint.

- Fuel cells – now getting much closer to commercial production, which will allow remote area power generation and not necessarily require major gas transmission lines. Field trial units are already in place, plus Japan has a large number of commercial units in operation. These cells offer the opportunity to avoid major "poles and wires" and their attendant losses and could be well suited to smaller community generation schemes.

- Micro turbines – have also made significant advances in recent years and will allow for local generation of electricity.

- Gas powered vehicles (GPVs) – all types – whether using natural gas or LPG. Substantial fleets of gas powered vehicles now growing further in Mumbai, New Delhi, and many places in Asia/Pacific. While LNG buses and prime movers seem to be gaining favor in developed economies, CNG conversions for taxis and buses have made good inroads in lesser developed countries. The key issue is around enabling the necessary infrastructure for refueling, with good networks of retail outlets required to gain customer acceptance or larger commercial fleets having their own infrastructure. This technology offers substantial opportunities for the replacement of imported gasoline with cleaner and quieter domestic gas.

- Gas appliances – required for new retail and small industries gas markets, which could initially be imported from Japan, Korea, etc., and later manufactured locally, if demand warrants it – with items, such as stovetops, rice cookers, and hot water heaters [which can be combined with solar heaters], all readily available. This is particularly important in creating gas markets when there is no space heating load and merely relying on the relatively low volume/household consumption of wok burners will not quickly grow the gas market.

6.10 Typical Issues in Attracting Investment and in Gas Market Creation and Expansion

A checklist of the typical issues that policymakers must address in turn in attracting investment in gas industry infrastructure and in promoting the creation and expansion of a natural gas market is set out in the table below, together with our recommended strategies for consideration. It is nonetheless emphasized that each economy requires policies and strategies that are tailored for its specific needs.

Exhibit 6.2: Typical Issues to Be Addressed by Policymakers and Recommended Strategies

TOPIC	ISSUE TO BE ADDRESSED	RECOMMENDED STRATEGY
Availability of resources	Is natural gas available in sufficient quantities to satisfy potential future demand, either from indigenous or imported sources?	The potential for indigenous production should be thoroughly investigated. Exploration and development incentives should be provided. If insufficient indigenous resources are available, consideration must be given to importing gas, either by pipeline or in the form of CNG, LNG or liquids. In any case, long-term supply contracts will be necessary.
Affordability	What is the burner-tip price that consumers will have to pay for gas?	Gas should be supplied to consumers at market-based prices. If low-income consumers cannot afford market-based prices, the government may consider subsidies or rebates for the needy. Economy-wide subsidies should be avoided.
Competitiveness	Are coal and other alternative fuels available and at what price? Can switching be achieved without undue cost?	Gas must compete with coal and other alternative fuels on a life-cycle basis. Natural gas should be able to compete with other fuels in the end-user market according to market-based prices. Cross-border gas trade, if allowed, will increase gas-to-gas competition. Investment in switching capacity should be encouraged.
Security of supply	What is the level of risk that gas supply could be interrupted? Interruptions could be caused by production and transportation problems and events of *force majeure*, both in the domestic and international markets.	Diversity of supply sources is the main strategic response. For domestic gas production, the creation of a stable and attractive climate for private investment is necessary for the long-term development of an adequate supply of natural gas. For imports, reliance must be placed on sustainable contractual arrangements, ideally with a diversity of competing supply sources.

Immaturity of the domestic market	Who are the gas customers in the domestic market (high-volume, industrial end-user, power generators or small-load commercial and residential end-users)?	A gas market must be created – it will not automatically happen. There should be reliable demand forecasts, an "industry vision" by the government, structural and regulatory reforms, facilitation of investment in infrastructure and transparency in everything that is done.
Infrastructure	What is the extent and condition of the pipeline network and storage and other facilities that provide the essential infrastructure for the bulk handling of gas?	The domestic investment climate must be stable and attractive for both domestic and foreign investors to induce the necessary level of investment. The requirements of bankability must be satisfied.
Technology	Are appropriate technologies for natural gas use available?	There are a number of options, such as the use of LPG as a transition fuel. Combined cycle gas turbine (CCGT) technology is an option for power generation.
Competition	Is the industry dominated by a state monopoly or are there competitive activities?	Wide-ranging structural and regulatory reform may be necessary. Commercialization and privatization of a state monopoly should be considered. The progressive introduction of competition is the means for enhancing benefits to the consumer and achieving efficient resource allocation. A level playing field is necessary.
Regulatory regime	Is there a light-handed regulatory regime that guarantees competitive neutrality and provides incentives for investment in infrastructure?	Price controls should be avoided except for pipelines and other monopolistic facilities. The regulatory regime should provide incentives for natural gas use, such as allowing for long-contract development periods, long-purchase commitments, oil-equivalent pricing, and payment guarantees. Allowing access by third parties to production facilities, pipelines and storage facilities can reduce development costs.
Environment	What is the policy position with respect to the environment, Kyoto, global warming and impacts on the community?	Carbon emissions should be accounted for and, subject to local policy, priced in to all new projects and investments.

6.11 Summary and Conclusions

Natural gas consumption in APEC economies holds great potential, especially among the developing member nations. The developing economies are expected to experience a higher rate of energy and natural gas demand growth, and as such must develop their infrastructure capabilities to keep up with this surge in demand. Worldwide natural gas demand as a whole is projected to more than double over the next 20 years, driven by positive global economic growth, an increasing desire of many economies to diversify their energy mixes away from a heavy dependence on foreign oil, and a growing collective concern for the environment.

Natural gas is a more efficient, cleaner-burning fuel than competitor fuels, and holds benefits both for the industrial and the residential sectors. Impediments to continued growth and development in the utilization of natural gas include deficits in related infrastructure due to a lack of investment and lackluster investment due to fragile institutional frameworks and political uncertainty.

Reforms across financial and governmental institutions, as well as the gas industry itself, will be necessary to support greater use of natural gas in developing APEC economies. Each economy has its own specific needs and priorities that require tailored solutions to be developed.

The checklist of typical issues and recommendations included in this chapter may provide a useful starting point for policymakers in individual economies.

7 ISSUES, INFORMATION AND DATA NEEDS FOR EXPANSION OF NATURAL GAS IN THE POWER GENERATION AND INDUSTRIAL SECTORS

7.1 Introduction

Gas presents certain advantages as a fuel for power generation; it is clean, efficient, and gas-fired power plants quickly reach maximum capacity in case of a peak in demand. Natural gas can also be used as a feedstock by the petrochemical industry. APEC economies could thus benefit from maximizing their utilization of natural gas for these two purposes.

Natural gas is unequally developed among APEC economies. While in some economies maximum usage has almost been reached, others still have room for developing their natural gas sector. Several issues must be addressed to do so, and information and data play a critical part in assessing the viability of natural gas projects.

7.2 Current Status of Natural Gas Usage in the Power Generation and Industrial Sectors

Power generation and the petrochemical industry are the largest consumers of natural gas in most APEC economies. The level of gas utilization in this sector varies widely across these economies, however, even among those with a similar level of development. This chapter aims at providing a brief overview of the current usage of natural gas for power generation and industrial purposes.

Japan, Korea and Chinese Taipei use natural gas primarily for power generation purposes (more detailed figures can be found in Chapter 2 of this report). A large part of the power generation infrastructure in these economies is gas-fired. None of these economies has significant domestic natural gas reserves, and gas is imported in the form of LNG. These economies have all been pioneers in the use of LNG to fuel large power plants.

The situation is quite different in the United States and Canada where power generation represents between 10% and 20% of the total end usage of natural gas. Industry is the largest consumer of natural gas, with about 40% of the total. Natural gas is used to fuel the large petrochemical industry in the Gulf of Mexico region in the United States. Singapore has a similar situation as natural gas consumption is driven partly by power generation and also in large part by the Jurong Island petrochemical complex. In Australia and New Zealand, power generation and industry each represent approximately 40% of the total end usage; natural gas is the third energy source in Australia after coal and oil, but is growing with the discovery of new reserves.

Among developing APEC economies, the picture is even more diverse. The Russian Federation contains the world's largest natural gas reserves and is a heavy user of gas both for power generation purposes and for its petrochemical industry, even though both suffer from aging facilities. Natural gas represents

53% of the total energy consumption in Russia, by far the largest percentage among the APEC economies. Malaysia also has large gas reserves and owns the largest LNG liquefaction facility in the world. Similar to Russia, Malaysia is highly dependent on natural gas for its power generation purposes and also uses gas to supply a dynamic petrochemical industry.

Indonesia also contains very large reserves and is a major LNG exporter, but due to a poor distribution network, little gas is used for domestic power generation purposes. However, a price subsidization system has led to development of a large domestic petrochemical industry. This subsidization scheme has increased the demand for gas and reduced the incentive for discovering new reserves. This in turn has reduced the amount of gas available for export as LNG and forced Indonesia to cancel a large number of LNG cargos.

China's power generation sector is currently dominated by coal, a fact which stems from the abundant domestic coal reserves. A surge in electricity demand and rising environmental concerns are, however, prompting the Chinese government to develop new gas-fired power plants. Some of this gas will be sourced from domestic fields, while the remainder will be provided by LNG imports.

Most South American countries rely heavily on hydroelectricity for power generation and do not consume much natural gas. This statement holds true for the South American APEC members, Chile and Peru. Chile relies on hydroelectricity for more than half of its power generation, and difficulties in importing natural gas also limit the industrial usage. However, Chile is willing to increase its natural gas consumption and is considering importing LNG as an alternative to the unreliable pipeline supply from Argentina. Peru also has relied heavily on hydroelectricity and coal, but recent developments in the Camisea gas fields have prompted the construction of new gas-fired power plants and spurred industrial development.

Viet Nam is in a similar situation, having relied traditionally on hydroelectricity and coal for power generation. However, Viet Nam is experiencing a strong growth in demand for electricity and at the beginning of this decade, began to build new gas-fired power plants fueled by recently discovered domestic gas reserves. The newly explored gas fields are also expected to fuel a growing domestic petrochemical industry.

Mexico has traditionally relied on oil for more than half of its power generation, and very little on natural gas. The government has recently decided to shift its policy away from oil and a large number of power plants are being converted to gas; several LNG import terminals are also being constructed and more are planned. Thailand is following a very similar path, converting most of its oil-fired power plants to cleaner gas-fired facilities. More than 75% of Thailand's natural gas consumption is for power generation purposes, as industrial usage is not very developed.

In Papua New Guinea, almost 100% of the domestic natural gas consumption is dedicated to power generation as the economy does not have a petrochemical industry. Papua New Guinea's natural gas reserves are still underexploited and are expected to be developed in the near future. The same can be said for the Philippines, which, despite large natural gas reserves, has only developed the Malamapaya gas field. Malampaya fuels a power plant, but most of the economy's electricity is produced by oil or renewables.

7.3 Issues for Gas Utilization in the Power Generation and Industrial Sectors

Increasing natural gas usage for power generation and industrial usage requires major infrastructure investments and faces many challenges among the numerous and varied APEC economies.

First, in certain economies, natural gas usage seems to be close to its maximum capacity. This seems to be the case for Japan, Korea, Malaysia, the Russian Federation, and Chinese Taipei. In these economies, natural gas already fuels a large majority of the power generation capacity, and it may not be prudent to further increase these economies' dependency on a single fuel. Malaysia is considering diversifying its power generation fuel mix precisely to reduce its sole reliance on natural gas.

Natural gas usage cannot be indefinitely increased for industrial purposes either, as the petrochemical products' markets have a limited demand. While some economies can benefit from abundant and low cost natural gas resources, as well as low labor costs, other economies are not suited to develop a petrochemical industry. However, some economies, such as China or Viet Nam, could develop their petrochemical industry as part of their industrialization process.

Whether developing a petrochemical industry or developing power generation capacity, increasing natural gas usage will require major capital investments. Natural gas is difficult to transport and store. If it is possible to build power plants close to a gas field, such as in Malampaya in the Philippines, Phu My in Viet Nam or Camisea in Peru, then this challenge is less important. But in the case of an economy without abundant gas resources, such as Chile's, gas must be transported either by pipeline or in the form of LNG to the power plant facility. Both require major infrastructure investments.

The sheer cost of building gas infrastructure is also an issue that needs to be taken into consideration. Power plants, pipelines, LNG facilities and petrochemical plants are all high-cost developments and, therefore are strong candidates for project financing. Project finance enables a wider variety of institutions to be involved in the financing process, ranging from multilateral development banks to export credit agencies to private sector banks and is often the structure most suitable for attaining the debt volumes necessary to finance the needed infrastructure.

7.4 Information and Data Needs for Expansion of Natural Gas Use in the Power Generation and Industrial Sectors

Expanding the use of natural gas for power generation or for use in developing the petrochemical sector requires major capital investment in an economy's infrastructure, whether it is undertaken by the government or private sector. For this reason, the decision to build a gas-fired power plant, a pipeline, an LNG terminal, or a petrochemical plant should be based on a variety of factors and evaluated using sufficient and reliable information and data.

Demand for electricity or for petrochemical products must be thoroughly assessed. Regional integration can play a positive role in creating a regional market for petrochemical products, but the competitiveness of petrochemicals must be assessed in a global context. In the case of power generation, demand assessments will be domestic or possibly regional. Sufficient and reliable data must be gathered to forecast the future demand for electricity. Gas-fired power plants are expensive to run in comparison to those fueled by coal or oil. Their long-term profitability must be ensured for financing to be successful, especially if realized on a project finance basis.

Data on supply must also be reliable. In the case of a pipeline or an LNG terminal, gathering this data can be difficult, and the commercial contracts rather than data will help secure long-term supply and the viability of the project. In the case of a power plant or petrochemical plant fueled directly by a dedicated gas field, it is important to have an accurate estimate of the recoverable reserves in the field and of its estimated life.

Beyond data, information on natural gas can also play an important part in increasing the role of natural gas in power generation. This is particularly relevant for LNG. Many projected LNG regasification terminals in the United States, such as the Clearwater terminal planned in California, which could fuel power plants, are being fought by local residents, and delayed or abandoned for this reason. Sometimes citizens consider LNG a safety risk, a feeling that often stems from a lack of information on how the gas is handled. Better information dissemination and increased public awareness regarding LNG could smooth the permitting process and enable the development of new gas-fired power plants.

Data gathering is an area where APEC is particularly active. The Asia Pacific Energy Research Center (APERC), created by APEC in 1996 as an affiliate of the Institute of Energy Economics, Japan (IEEJ), has developed a comprehensive energy database aimed at understanding energy demand and supply dynamics in APEC economies. Continuous dialogue between APERC and APEC economies' statistics offices make it possible to improve the quality of data collection and disseminate best practices.

Indicators collected by APERC for natural gas are a strong starting point for economies looking to make informed decisions on natural gas development. This set of indicators includes:

- indigenous production
- opening and closing stocks and stock changes
- imports
- exports
- gas processing
- gas recovering
- gas power generation
- final total energy consumption by energy and by end use

Other indicators would be interesting to develop, targeting more particularly natural gas reserves for the economies that possess significant reserves and are aiming at better exploiting them. The United States Energy Information Agency offers an interesting set of indicators in this respect; it collects data on the proved reserves of:

- dry natural gas
- wet natural gas
- non-associated natural gas
- associated natural gas
- NGL
- Coal-bed methane
- Offshore deepwater gas reserves

These indicators enable both governments and the private sector to have a detailed picture of the nature of an economy's natural gas reserves. The ratio of wet gas to total reserves is a good indicator of the potential for developing a gas-based petrochemical industry. Large reserves of non-associated gas are a favorable environment to develop LNG liquefaction facilities. Deepwater and coal-bed methane reserves are more difficult and costly to exploit.

Other useful indicators for economies currently producing natural gas include the number of wells drilled and the amount of natural gas flared in the course of oil production. These two indicators can be used to improve the efficiency of natural gas production.

For importing economies, the focus is slightly different. The key is to be able to accurately forecast the demand and not face shortages. Forecasting demand traditionally starts by gathering detailed data on end uses of energy and then estimating the growth of each sector. Energy demand should also be broken down by region to estimate future needs and plan new projects accordingly. Demand forecasting rests heavily on reliable economic growth forecasting.

Data collection should also include storage capacity to measure the ability of an economy to face a short term supply shock.

Price data is valuable for both importing and exporting economies. Several indicators can be used:

- wellhead price
- import/ export prices
- retail prices (residential and industrial)
- electric power price

For exporting economies, gathering data on wellhead prices can help them to assess the competitiveness of their gas in regional markets and to make informed decisions on whether to export gas or sell it exclusively on the domestic market. For importing economies, the analysis of natural gas prices should be done in comparison with prices of competing fuel (such as coal) to assess the competitiveness of natural gas as an energy source. Depending on the outcome of this analysis, natural gas use can be limited to residential consumption or extended to industrial and power usages. Price competitiveness of natural gas is a key component of increasing its consumption.

7.5 Summary and Conclusions

Natural gas is being increasingly used by APEC economies for power generation and industrial purposes. Recent discoveries of new gas resources and general economic development have spurred this process in some economies, such as China, Peru, and Viet Nam. Undeniably, the key to developing increased natural gas use is investment in related infrastructure; many economies do not exploit their natural gas resources to full capacity because of the lack of data and information required to validate the pursuit of those investments.

Developing a natural gas sector requires major investments that should be supported by strong evidence of growth in demand. Investing the resources necessary to develop and maintain critical data and information is one way that APEC economies can support the development of natural gas markets.

8 CASE STUDIES INVOLVING THE POWER GENERATION AND INDUSTRIAL SECTORS IN SELECTED APEC DEVELOPING ECONOMIES

8.1 China's LNG Market Development

8.1.1 The Demand for Natural Gas

China has become a major player in the world energy markets; in 2004 it surpassed Japan as the second largest importer of oil, lagging only behind the United States. Despite this ranking, coal remains China's most important source of energy. China is the world's largest producer and consumer of coal, according to the BP Statistical Review, coal made up 69% of China's primary energy fuel consumption in 2004. China's huge demand for energy is driven in part by the energy-intensiveness of its economy; the amount of energy China uses to produce one unit of GDP is well above international standards. In response to these trends, the Chinese government has worked towards developing a new energy policy that diversifies its energy imports, lessens the environmental impact of energy consumption and increases energy efficiency.

A major part of this energy strategy has focused on increasing the role of natural gas as a primary energy source for China's economy. Currently natural gas makes up about 3% of China's primary energy mix. The government is seeking to increase that figure to 10% by 2020. Estimates indicate that the demand for gas will reach between 85 and 125 billion cubic meters (bcm) by 2010 and 180-250 bcm by 2020. This growth is expected to be led by strong demand from the power generation sector, followed by increases in residential and industrial demand.

China has just recently commenced importing gas for domestic use. The development of the production and transportation infrastructure necessary to transport gas from the large reserves in the north-central and north-western parts of the economy to demand centers on the eastern coast, along with the development of offshore fields, has enabled domestic supply to meet recent growth in demand. However, the National Development and Reform Commission (NDRC) estimates that domestic production will reach 80-100 bcm by 2010 and 130-150 bcm by 2020; levels insufficient to keep up with projected demand. The shortfall will have to be met by increasing levels of imports.

8.1.2 The LNG Strategy

One of the issues that China faces in developing the gas supply necessary to meet its future needs is that much of its residential population and industrial bases are situated in the southeastern part of the economy, far from its domestic reserves in Inner Mongolia and Xinjiang. These demand centers are even further away from possible pipeline imports from Kazakhstan and Russia. In addition, the Chinese government is interested in maintaining a diversified supply of energy. The solution created by the government was to encourage the development of LNG import terminals. These terminals could be located close to coastal demand centers, as well as enable the establishment of a diversified portfolio of possible energy sources.

The three national oil companies, China National Offshore Oil Corp. (CNOOC), China Petroleum & Chemical (Sinopec), and Petrochina, took the lead in developing the terminals. At first, as many as eighteen terminals were proposed. However, fears of overcapacity and supply caused the government to intervene by announcing that only one terminal per province would be allowed. An analysis compiled by researchers at the East-West Center and FACTS, Inc. and published in *Oil & Gas Journal* lists eight terminals that are planned or proposed, their estimated capacities, and their targeted timeframes.

Exhibit 8.1: China's Planned or Proposed Import Terminal Capacity[36]

	Guangdong	Fujian	Zhejiang	Shanghai	Shandong	Liaoning	Jiangsu	Guangxi	Total
2005									
2006	3.9								**3.9**
2007	3.9								**3.9**
2008	3.9	2.6							**6.5**
2009	9.9	2.6			3.0				**15.5**
2010	9.9	2.6	4.0	4.0	3.0		3.0		**26.5**
2011	9.9	2.6	4.0	4.0	3.0		3.0		**26.5**
2012	12.9	2.6	4.0	4.0	5.0	3.0	3.0		**34.5**
2013	12.9	2.6	4.0	10.0	5.0	3.0	3.0		**40.5**
2014	12.9	5.0	4.0	10.0	5.0	3.0	3.0		**42.9**
2015	12.9	5.0	10.0	10.0	5.0	6.0	5.0	3.0	**56.9**

Estimates for a number of these projects vary as many of the decisions regarding final capacities and timeframes have not yet been finalized.

One strategy that is common for many of the Chinese LNG terminal developments is the concurrent development of gas-fired power facilities. The initial plans for the Jiangsu terminal include the development of 2,400 MW of power generation, and many other terminal developments also include plans for power plants. This strategy accomplishes three main objectives. First, it directly achieves the national strategy of increasing the proportion of gas-fired power generation. Second, it provides a foundation offtaker for the gas from the terminal, increasing the likelihood that the terminal will get financed and built. Finally, the co-development of the terminal and power projects achieve synergies that create cost savings, enable efficient deployment of capital and reduce the overall cost of the electricity that is produced.

[36] Fesharaki, Fereidun and Wu, Kang. *Oil & Gas Journal*. "Higher natural gas demand has China looking worldwide." 7/18/2005. p. 51.

8.1.3 The Guangdong Terminal

Much can be learned through a closer examination of the first successful terminal development in China, the Guangdong LNG terminal. This US$850 million project is being constructed in two phases. The first phase has a planned capacity of 3.7-3.9 mtpa and includes the construction of a 300 km trunkline system connecting the terminal to bankable customers in Hong Kong. This phase is expected to begin operation in 2006. Two new gas-fired power plants are being constructed and will be fueled by gas from the terminal. The terminal will also supply fuel to at least four other existing power plants. Phase II will expand the terminal's total capacity by 2-6 mtpa and push the trunkline system out, enabling the terminal to serve a larger geographic region.

The sponsors of the project included CNOOC (33%), BP (30%), and several domestic gas distribution and power generation companies. This sponsorship consortium is in many ways typical of sponsor groups at the other proposed terminals. These groups generally consist of a state oil company with a significant equity stake, and one or more local gas or power companies that will also be major offtakers. In this case the consortium also included a foreign oil company, BP. Although the Guangdong terminal did not end up purchasing LNG from a BP-sponsored liquefaction plant, another Chinese terminal in which BP holds a stake, Fujian LNG, did. The combination of a state-owned oil company and local offtakers also holds some integration advantages for the terminal development. CNOOC is able to leverage the creditworthiness derived from its strong backing from the Chinese government to secure long-term LNG supply. Banks, which may not be familiar with the smaller gas and power companies who make up the majority of the terminal's offtake agreements, are comforted by the fact that these companies are equity holders in the project and thus have added incentive to honor offtake agreements.

The financing of the Guangdong project is of particular note, as it was the first large-scale energy infrastructure project financed on a non-recourse basis by China's domestic banks. Seventy-five percent, about US$635 million, of the project cost was debt funded, with 90% of the debt provided by China's four largest state banks. Project financings are complex transactions that require a great deal of specialized knowledge. Strong participation by China's major banks in this deal will provide a foundation for similar financings in the future.

8.1.4 Issues

Despite the early success of the Guangdong terminal and CNOOC's second terminal in Fujian, there is still an air of uncertainty surrounding China's future demand for LNG. These concerns revolve around two main issues; the development of a pipeline import supply network and the current high price of LNG and its impact on the competitiveness of natural gas versus coal.

Pipeline projects under development that plan to bring natural gas to China from reserves located within the borders of its northern neighbors could supply up to 70 bcm annually in the most optimistic scenario.

These projects include an 8-10 bcm/yr pipeline from Kazakhstan and two 20-30 bcm/yr pipelines from Russia, one entering China from the northwest and one from the northeast. While it is uncertain that all three projects will become reality, it is likely that one or two of the pipelines will be built. This will not have an adverse affect on LNG terminals located on the southern coasts of China, like the Guangdong and Fujian terminals. However, as the terminal locations move further north, possible competition from pipeline imports becomes more of an issue, especially if the pipeline along the northeastern route is constructed.

Of greater concern is the current price of LNG. CNOOC was able to negotiate favorable supply contracts for Guangdong with the North West Shelf liquefaction project in Australia. At that time, the possibility of excess liquefaction capacity loomed large, enabling the Chinese buyers to negotiate more favorable terms with the suppliers. However, as Chapter 5 of this report shows, supply is expected to tighten over the next couple of years. Strong demand from Japanese and American markets and high oil prices have increased the price for LNG, as has been evident from the inability of CNOOC and Chevron to come to terms on supply contracts for LNG from the Gorgon facility, a liquefaction plant also located in Australia. Higher LNG prices make the resulting natural gas less competitive with coal, China’s largest source of primary energy. Unless the Chinese government enacts policies that put a higher cost on the environmental impact of coal usage, high gas prices will encourage construction of additional coal-fired power plants, reducing, to some extent, the possible role of LNG and natural gas in China’s economy.

This lack of certainty regarding future demand for LNG makes the financing of current LNG terminals more complicated. Adding to this complexity is the difficult regulatory environment in China that does not encourage the use of long-term power purchase agreements (PPAs). This has a cascading effect. The lack of long-term PPAs makes financing difficult for the new power plants that are integral to providing offtake for LNG terminals. Without these plants and the demand they provide, financing of the LNG terminals themselves becomes riskier. Even if the power plants are built, without long-term PPAs in place, the offtake agreements they make with the LNG terminal provide less effective security to the terminal’s lenders than would be the case if long-term agreements were available.

8.1.5 Conclusion

China’s demand for energy is growing rapidly, and it is clear that natural gas and LNG will play a strong role in meeting that demand. Despite some uncertainty regarding the exact nature of future demand, China’s early LNG terminals have been successfully developed and financed, and can provide insight for additional terminal development in China and elsewhere in the region. Co-development of gas-fired power plants provides a foundation of demand for the terminal. Integrating offtakers as equity participants in the terminal project creates an alignment of interests and provides some measure of comfort to lenders, who may not otherwise be completely familiar with the credit history of some of these smaller domestic firms.

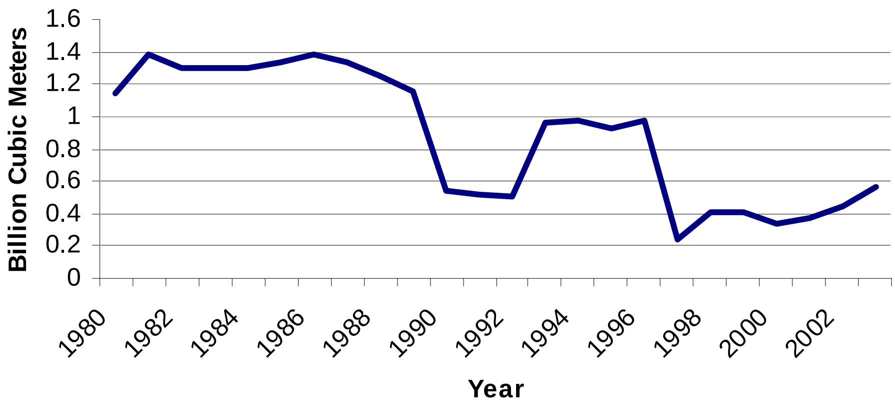
However, in light of the emphasis on bank reform in China, it is probable that domestic banks will have to limit their exposure to these LNG terminal projects, at which point greater participation by foreign lenders will be necessary. China will need to develop a stronger legal and regulatory framework that allows lenders greater ability to manage some of the risks of these projects if it wants to achieve all the objectives of its current energy strategy.

8.2 Peru – Development of the Camisea Gas Field

8.2.1 Peru's Natural Gas Sector

Peru's natural gas reserves at the beginning of 2005 were estimated at 250 bcm, or 0.1% of the global total, making Peru the in fourth largest holder of natural gas reserves in South America.[37] Peru's production of natural gas has been volatile since the 1980s, with steep declines in production noted between 1989-91, and 1996-97, with a recovery period in between.

Exhibit 8.2: Peru's Natural Gas Production



Source: EIA – International Gas Production Data

Peru's natural gas production steadily climbed from 1998 to 2003, but it will increase exponentially with output from the economy's new gas production project, the Camisea fields.

8.2.2 The Project

Camisea, which went online in September of 2004, consists of multiple natural gas fields in the Ucayali Basin of southeastern Peru along the Camisea River. The San Martin and Cashiriari fields, known together as Block 88, make up a large part of Camisea and house an estimated 192.5 bcm of proven reserves, plus an additional 411 million barrels of natural gas liquids. To ensure production for LNG export, Camisea has also recently secured production rights for Block 56, which is adjacent to Block 88

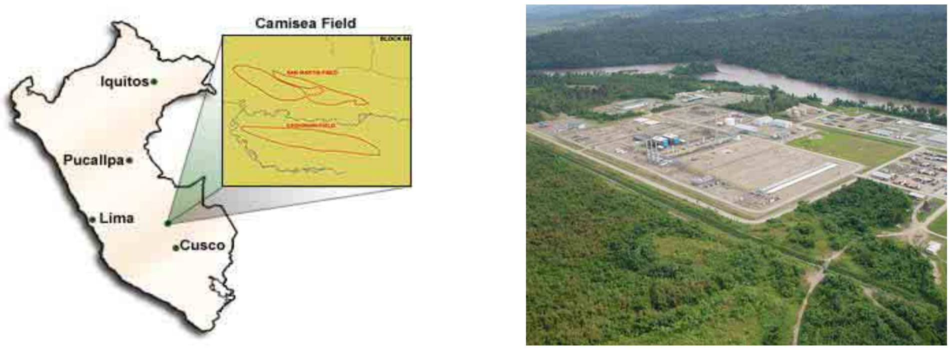
[37] BP Statistical Review of World Energy June 2005

and contains over 99 bcm of total reserves. If the project continues as planned, it will make Peru a net exporter of natural gas; Peru's production volume for the project's first month in operation, 104 mcm was twice that of the same month during the previous year.[38]

8.2.3 Origins of the Project

The Camisea gas fields were discovered between 1983 and 1987. An initial Terms Agreement for exploitation was signed between Petroperu, the state-owned oil company, and Shell in 1988, but negotiations were terminated before the two sides could reach an agreement. In 1994, an Evaluation and Development contract was signed between Petroperu and Shell again. A feasibility study was submitted in 1995, and the next year an exploitation contract was signed by a Shell-led consortium and Petroperu. The consortium backed out of the contract in 1998, and, in 1999, the Special Committee for the Camisea Project solicited international public bids to award the exploitation license agreement and three concessions for gas and liquids transportation. In February and October of 2002, the license agreement and transportation concessions were awarded respectively. In December 2002, the contract and three concession agreements were signed in Lima. Gas reached Lima in September 2004, twenty years after the initial exploration. The first exports of natural gas will not take place before 2009, a result of delays in signing commercial agreements and exploitation agreements with the government of Peru.

Exhibit 8.3: The Camisea Field



Source: Proyecto Camisea (http://www.camisea.com.pe/)

8.2.4 Operations

Upstream. The upstream consortium, made up of Pluspetrol Peru Corp., Hunt Oil Co. of Peru, SK Corp. and Tecpetrol del Peru (which is wholly owned by Techint Group), has a contract that allows it to extract gas from Block 88 for 40 years. Pre-operational expenditures are estimated to have reached US$550 million.

[38] EIA – Country Analysis Brief, Peru

Transportation. Transportadora de Gas del Peru (TGP), which is led by Tecgas (Techint Group) and made up of Pluspetrol Resources Corporation, Hunt Oil Co., Sonatrach Petroleum Corporation, Grana y Montero, SK Corp. and, ~~and~~ Tractebel, was awarded the three 33-year downstream contracts and is in charge of transportation. The three different contracts are for transportation of gas from Camisea to Lima; transportation of natural gas liquids from Camisea to the coast; and distribution of gas in Lima and Callao (this part of the contract is only operated by Tractebel). The contract included the construction of two pipelines at a total cost of US$850 million: a 714 km pipeline for natural gas and a 540 km pipeline for natural gas liquids (NGL). The parallel pipelines run both to Lima and Callao, to a gas processing plant in Las Malvinas and to a fractionation plant in Paracas Bay, on the Pacific Coast, where natural gas liquids can then be exported. Building the pipeline was a technical challenge due to the high elevation in the Andes and the sensitive environment. The engineering challenge was made even more complex by the fact that the Camisea project decided to adhere to a strict "no roads" policy, meaning that no roads could be carved in the Amazonian forest, and all construction materials had to be brought by ship or helicopter. The natural gas pipeline has an initial capacity of 285mmcf/d to be raised to 450 mmcf/d in 2015; the NGL pipeline has an initial capacity of 50,000 b/d

The pipelines were completed in 2004 and have caused strong opposition from both local indigenous peoples and international environmental organizations. The controversy was partly responsible for the delay in building the pipeline. Originally, Shell and Mobil were developing the project but abandoned it in 1996, partly because of President Fujimori's request to build an uneconomical 500 MW power plant in the jungle, and partly because of international protests that led to the resignation of Citigroup as financial advisor.

The TGP pipeline crosses protected natural and Indian reserves in the Amazon jungle, and the gas fractionation plant is located next to Peru's only marine refuge, and both have been under intense scrutiny from activists. After the withdrawal of Citigroup, the bank started working on a set of stringent environmental standards together with the IFC and ABN Amro; these standards are known as the Equator Principles. Also, the controversy surrounding the environmental aspects of the project likely played a part in the decision of the US Ex-Im Bank to not grant the US$ 200 million loan it was initially considering. Only the Inter-American Development Bank (IDB) stepped in with a US$ 75 million loan.

The IDB has recently become the target of international protests after five leaks occurred in the pipeline between 2004 and 2006. The IDB announced a review of the project, while Osinerg, Peru's energy regulator, is preparing a tender for an international audit of the pipeline construction.

Distribution. In 2002, Tractebel was selected by TGP to operate the distribution service and was later added to the consortium. Natural Gas of Lima and Callao, which is owned by Tractebel, was created to manage distribution through the two cities. Tractebel is to construct a 60 km pipeline, with initial investments of US$55 million, to distribute gas to the industrial sector and power generators in the cities of Lima and Callao. Although Lima has an existing distribution network through which to distribute gas nation wide, the project plan includes an expansion of this pipeline network to reach industrial, commercial and residential consumers across the economy. The total investment need is estimated at US$170 million.

8.2.5 Economic, Fiscal & Social Benefits of Camisea

The development of the Camisea natural gas project in Peru is central to the economy's overall energy strategy, and thus is tied to the economy's growth and development in the coming years. The project aims to increase natural gas production with the end result of making Peruvian industry more competitive; improving the economy's trade balance in the hydrocarbons sector and generating revenue through exportation of excess product; and dispersing the social welfare effects to the economy's population. Peru will be able to substitute its imports of diesel and liquefied petroleum gas (LPG) and export naphtha and LPG products, improving the economy's hydrocarbons trade deficit; according to official figures, Peru would realize savings of US$ 1.9 billion per year in hydrocarbon imports. Despite Peru's endowment of natural gas, the economy relies heavily on hydroelectric power; increased production of gas will allow the Peruvian power sector to diversify away from hydropower, which can be unreliable in times of drought, to more gas-fired generation facilities. Economic benefits will stem from increased FDI flows into the economy, the potential development of a gas-based petrochemical industry, and employment opportunities. The spill-over social effects will include an increased standard of living, a reduction in electricity tariffs and thus electricity prices, and decreased emissions of greenhouse-effect gasses into the environment. President Toledo's government forecasted a 1% increase of the GDP because of Camisea and promised a 15% drop in electricity prices. The idea is to reduce the dependence of the Peruvian power industry on coal and expensive imported oil. This will require the retrofitting of oil-fired power plants or the construction of new gas-fired power plants, and as of yet this has not occurred.

The benefits have however yet to be felt in Peru. Converting the power generation sector and industries to natural gas is a slow process, and incentives do not seem to be sufficient to lead to major changes. At a micro level, households also need incentives to switch to natural gas as their primary domestic fuel. Some conversion projects, such as converting buses in Lima to CNG, have been planned but not realized for lack of funding.

Regarding the fiscal benefits, 50% of Camisea's royalties (which at a rate of 38% are substantial) were to be earmarked for the regions crossed by the project and set aside for social and development funds. It appears that the distribution of these funds to the region is delayed. The IADB and the Peruvian government are nevertheless cooperating to solve this issue, as the distribution of royalties to the regions affected by the project was one of the conditions for IADB funding[39].

8.2.6 LNG Export Ambitions

Hunt Oil is also leading the push to develop an LNG export facility, including related port and pipeline infrastructure, in Pampa Melchorita, located roughly 170 kilometers (km) south of Lima. The Peru LNG Consortium, comprised of stakeholders Hunt Oil (50%), SK (30%) and Repsol YPF (20%), has delayed awarding an engineering, procurement and construction (EPC) contract for the US$2 billion JV project until the spring of 2006, pushing the venture's operational start-date back to 2009 or 2010. Part of the reason for the delay is that Repsol, which is slated to export 4 million tons per annum of the facility's LNG output, has yet to sign firm offtake contracts. Repsol submitted the lowest cost bid to supply LNG to Mexico's proposed regasification plant in the Pacific-coast town of Manzanillo, but the Mexican state power company and energy regulator CFE delayed selecting its preferred bidder[40]. Domestic pressure may further delay the call for bids on the politically-charged project as the July 2006 Mexican election approaches. Other causes for delay are land disputes with local government entities and the Peruvian congress' failure (as of yet) to agree upon a tax regime that will not undercut the state's legal and fiscal stability.

The Peru LNG facility will have an initial output of 16 Mcm/d, most of which is to be exported to the United States. Additionally, Peru has discussed the possibility of LNG exportation to Chile with ENAP, Chile's national petroleum company. Because both economies have intentions to build the related export/import infrastructure, LNG trade could potentially be more cost-effective than trading gas via pipelines through their shared border. Tractebel (Belgium), however, has held talks with the Chilean government about constructing a pipeline about 1,500 km in length, for an estimated cost of US$ 500 million. Camisea has stated that there will be enough gas for domestic consumption, LNG exportation and exportation to Chile via pipelines. Another option for a pipeline between Camisea and the Chilean market would be the Southern Cone gas pipeline. An agreement was signed in December 2005 between the Energy ministers from Argentina, Brazil, Chile, Paraguay, Peru and Uruguay creating a legal framework for this US$ 3 billion project which would link Peru's Camisea gas fields to Porto Alegre, Brazil.

Peru has also discussed forming a partnership with Bolivia for LNG exportation. Bolivia holds the second-largest proven reserves of natural gas (behind Venezuela) in South America, but is land locked and, thus has no access to water routes to export its resources. While there has been discussion of linking Bolivia's Margarita gas field with the Peruvian port of Ilo, located just north of the Chilean border, no plans are

[39] Elizabeth Brito, Senior Environmental Specialist, IADB, during the seminar "Energy Politics in Peru" held at the George Washington University, Washington DC, April 26, 2006

[40] Infrastructure Journal News online June 6, 2006

under development; and, the feasibility of connecting Bolivian gas fields to Peruvian ports is uncertain based on both economic and political factors.

Peru's LNG plans could potentially be hampered by the costs of delivering the LNG from the Camisea gas fields to the coast crossing the Amazon jungle. The stringent environmental standards imposed to the project are likely to raise the construction costs, which could affect Peru LNG's competitiveness on the Pacific Basin market.

8.2.7 Financing

The entire project, consisting of natural gas production, processing, transportation, and distribution, will cost US$1.6 billion. For the US$1.2 billion transportation portion of the project, TGP has invested US$850 million, and the Inter-American Development Bank, along with the Corporacion Andina de Fomento, has approved US$135 million in financing for Transportadora de Gas del Peru. The financing will consist of a US$75 million A loan with a term of up to 14 years, and a US$60 million syndicated B loan with a term of up to 12 years. An additional US$270 million in debt was sourced from inside Peru: US$200 million in a floating-rate dollar facility; and US$70 million in Peruvian Soles, led by Banco de Credito Peru.[41]

Financing for the US$ 3 billion Peru LNG project has not yet been structured.

8.2.8 Lessons Learned

The fact that it took twenty years to bring the gas from Camisea to Lima is a good indicator of the difficulties faced by the project. Most of these difficulties stem from both local and international opposition to a project that would cross the Amazon jungle. Managing environmental concerns is likely to be a tough challenge in any economy trying to develop its natural gas resources. Dialogue and the enforcement of tough standards seem to be the best ways to approach the issue. However, while beneficial for Peru's environment and population in the long run, these stringent environmental standards may affect in the nearer term Peru's competitiveness on international energy markets, and could hamper the economy's export potential.

8.3 Philippines – The Malampaya Gas Field

8.3.1 Overview of the Electricity Sector in the Philippines

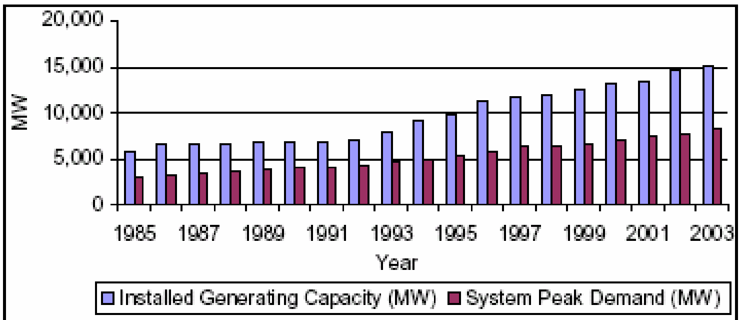
The Philippines's electricity sector has been faced with difficult times, with a series of shortages and blackouts, and a ballooning public debt. During the last 30 years, the Philippines has witnessed a

[41] Project Finance Magazine – "Latin American Oil&Gas Deal of the Year 2004"

constant growth in supply and demand for electricity. Over the last 30 years electricity consumption has increased 320% while population and GDP growth have increased 96% and 130%, respectively.[42]

Trying to keep up with increased consumption, the Philippines government has managed to maintain one of the lowest maximum demand-over-installed-capacity ratios in the region. This ratio did not exceed 55% during the mid 1980s, shortly before the power shortages of the late 1980s and early 1990s.

Exhibit 8.4: The Philippine's Maximum Demand/Installed Capacity



MW = megawatt.
Source: Department of Energy.

Source: Asian Development Bank

However, the conventional wisdom that a low maximum demand over capacity ratio is a safe indicator for availability of supplies did not apply to the Philippines, which faced severe shortages despite these seemingly encouraging ratios. As a recently published study by the ADB explains, "low availability of installed capacity, aging power plants, transmission bottlenecks, seasonality of hydroelectric plants, geographic mismatch of supply and demand, and poor management of reactive power" are some of the reasons why the extra capacity was not enough to preclude the shortages.[43] Finally, another major issue arose from the decision of the newly elected government led by Corazon Aquino in 1986 to abolish, for security reasons, the newly built 620MW power plant in Bataan, without taking actions to replace the lost capacity that this decision created.[44]

All of the above led to severe power shortages in the late 1980s and created a very difficult political situation for the Philippines government. To overcome the electricity shortages, the incumbent, newly elected government took significant market risk and started contracting U.S. dollar denominated take-or-pay agreements to sell electricity to the National Power Corporation (NPC) through IPPs. It took several years, until 1993, and numerous IPPs, more than 40, for the shortages to disappear. However, the

[42] Asian Development Bank, Sector Assistance Program Evaluation of Asian Development Bank Assistance to Philippines Power Sector p.4-5

[43] *Ibid.* p. 7

[44] *Ibid*. p. 9

problems were not completely overcome; they were only temporarily hidden and were brought to the surface again in the aftermath of the Asian financial crisis, this time not in the form of shortages but rather debt. In fact, NPC's dollar denominated debt from the take or pay contracts doubled, as the peso depreciated during the Asian financial crisis of the 1990s.[45]

8.3.2 The Malampaya Project

The development of the Malampaya project was deeply rooted in the situation described above. The US$4.5 billion project was meant not only to increase the security of supply and to decrease the dependency of the Philippines on imported fuel, but also to provide increased economic benefits through the predicted US$8-10 billion in revenues to the government[46] and the substitution of substantial energy imports with domestically sourced gas.

Exhibit 8.5: The Malampaya Project

Source: Shell Malampaya Project

The roots of the Malampaya project go back to 1989, when a small gas reservoir was discovered by Occidental Petroleum at a field known as SC 38. A year later, Shell Philippines Exploration B.V (SPEX) bought half of SC 38 and started looking for additional reserves of gas. It took another two years, before the Malampaya gas field was discovered in 1992, 70 km northwest of Palawan in the South China Sea. The necessary drilling found 2.7 tcf of gas and 85 mm barrels of condensate. These quantities were declared commercial in 1998 and SPEX bought the remaining 50% of SC38.[47]

However, these reserves also represented a serious engineering challenge because located in an area where the water depth was 820 meters.[48] Malampaya also contains sizeable quantities of oil, which has deemed uneconomical to recover due to the configuration of the reservoir. It was quite clear from the beginning that the economics of the project would make sense only in a fully integrated value chain, one in which the upstream, namely SPEX, would be harmonized with the downstream, namely the three

[45] *Ibid*. p. 9

[46] Malampaya Deep Water Gas to Power Project, celebrating the dawn of a new industry and the culmination of a country's dream p.2 http://www.malampaya.com

[47] http://www.malampaya.com

[48] Infrastructural Journal, Shell Philippines pursues larger market for Malampaya natural gas. 16 October 2001 (http://www.ijonline.com)

power plants in Batangas controlled or proposed to be built by the NPC, the First Gas Corporation and FGP Corporation, respectively. Such an undertaking implied a US$4.5 billion investment.[49]

In the meantime, SPEX sold 45% of its 100% ownership of SC 38 to Texaco in late 1999, followed by another 10% to the Philippines National Oil Company Exploration Corporation (PNOC-Ec) in early 2000. SPEX, as a result, reduced its share to 45%, but remained the developer and the operator of the project. On 16 October 2001, President Arroyo officially inaugurated Malampaya.[50]

8.3.3 Project Description[51]

- The design capacity of the platform was set at 508 mmscfd of gas and 32,800 bpd of condensate.
- Topside facilities consist of an integrated 3-deck structure measuring 92 m x 40 m with an operating weight of 14,000 tonnes and a dry (floatover) weight of 11,500 tonnes with a cellar deck engineered to be 24 meters above the sea.
- Malampaya Field is located 80 km northwest of Palawan Island in the South China Sea, with water depths ranging from 43 m at the platform, to 820m at the subsea wells.
- A Concrete Gravity Substructure (CGS), consisting of a hollow concrete box measuring 112m x 83m x16m high, weighing 91,000 tonnes with a net storage of 385,000 barrels, supports the topsides and temporarily stores condensate.
- The CGS incorporated 34,000 cubic meters of concrete, 12,000 tonnes of reinforcing steel, and 750 tonnes of pre-stressed steel strands.
- The platform has been designed to withstand a storm wave or earthquake with an intensity expected up to every 10,000 years, and for such events occurring up to every 100 years, to remain fully operational.
- The platform can be re-floated at the end of its operational life for environmentally responsible decommissioning.

8.3.4 Offshore Gas Pipeline

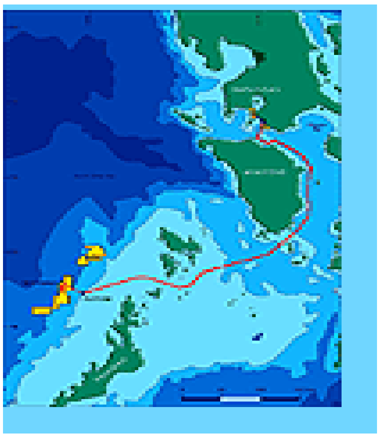
To get the gas from the Malampaya field to onshore a 504 km pipeline, with a total cost of US$1 billion, was required.[52] It took six months to build the pipeline and the whole undertaking has been praised, not only for having used cutting edge technology, but also for being environmentally friendly.[53]

[49] *Ibid.* http://www.malampaya.com

[50] Infrastructural Journal, President Arroyo inaugurates Malampaya 17 October 2001 (http://www.ijonline.com)

[51] The description of the Malampaya project and its technical characteristics are quoted from Halliburton's web page at: http://www.halliburton.com/kbr/projectProfiles/energy/auShell.pdf

Exhibit 8.6: Pipeline Route



Source: http://www.malampaya.com

8.3.5 Supply of Electricity

The Malampaya gas-to-power project supplies gas to three major power plants in the Philippines. The first one, Ilijan, belongs to the National Power Corporation (NPC). It is a 1200 MW plant operated through a build-own-operate (BOT) scheme led by Korea Power Corp., Mirant Philippines, Kyushu Electric Corp., and Mitsubishi Corp. The other two plants are the Santa Rita and the San Lorenzo plants. Their capacities are 1000 MW and 500 MW, respectively, and both are owned by the First Gas Power Corporation, a private domestic firm.[54] The GSPA's for the agreements were signed in December 1997, for Ilijan and in April 1998, for the two plants belonging to the First Gas Power Corporation.[55]

The plants are located in an extremely isolated region of the Philippines, on Luzon island. When the project development began in 1996, the location chosen for the Ilijan power plant was little more than jungle, accessible only by a narrow dirt road and without power supply. The engineering challenge to build a state-of-the art combine cycle gas-fired power plant in these conditions was thus considerable.[56]

---

[52] The cost is taken from Taylor-DeJongh's (TDJ) database. TDJ advised the government of the Philippines on this transaction.

[53] *Ibid*.

[54] Project Finance Magazine, Growth Platform. January 2002 (http://www.projectfinancemagazine.com)

[55] http://www.malampaya.com

[56] Washington Group International, Project profile on the Ilijan power project at http://www.wgint.com/project.php?id=13

8.3.6 Significance of the Project

The Malampaya offshore gas field has been a landmark project for the Philippines and its economy. It is by far the largest natural gas project in the history of the Philippines and the US$4.5 billion that was necessary for the investment constitutes one of the largest ever FDI in the Philippines.[57]

Beyond the numbers and the historical importance, the project has had other important results for the economy as a whole. By 2004, the Malampaya project managed to supply gas to meet 16% of the Philippines electricity needs, which is equivalent to 26 billion barrels of imported fuel.[58] Furthermore, the project was a clear indicator as to the ability of the economy to handle such a large foreign investment and to merge the vested interests of all the participating parties towards a common development goal. Finally, the Malampaya project has managed to achieve international recognition from such bodies as the UNEP and the ICC as one of the "Top Ten Best examples of Sustainable Development Partnerships in Action," thanks to its environmentally friendly design, construction, and operation.[59]

8.4 Viet Nam – Phu My 2-2 Power Plant

8.4.1 The Project

The Phu My 2-2 project is a 715 MW gas-fired power plant located in the Phu My industrial complex, 85 km from Ho Chi Minh City. The Phu My complex comprises four other power plants. Phu My 2-2 is fueled by natural gas from the Nam Con Son basin, under a gas supply agreement with state-owned company Petrovietnam. The plant began commercial operations in February 2005.

Phu My 2-2 was the first project in Viet Nam to be built through a 20 year build operate transfer (BOT) contract with private entities and the first large-scale project financing in the economy. It was also the first project with 100% foreign ownership (at least for the duration of the contract). A special purpose project company was set up, Mekong Energy Company (MECO), which is owned by Electricité de France (EDF), Sumitomo Corporation, and Tokyo Electricity Power Company (TEPCO). Electricity of Viet Nam (EVN) is the offtaker of the power produced at Phu My 2-2. After 20 years, ownership and operation of the power plant will be transferred to the Vietnamese government.

Phu-My 2-2 was a breakthrough for private power projects in Viet Nam; previously, only state-owned entities developed power plants. EVN was responsible for hydroelectric and gas-fired power plants and Vinacoal, the coal producing company, for coal-fired power plants. Phu-My 2-2 was also the first large-scale power project powered from a dedicated gas field rather than associated gas from several oil fields.

---

[57] EIA, Country Analysis Brief. The Philippines p.3 October 2004 (http://www.eia.doe.gov)

[58] Ibid. Project Finance Magazine

[59] www.inq7.net/gbl/2002/sep/03/gbl_5-1.htm

8.4.2 The Financing

Phu My 2-2 was financed using project finance, and was the largest such financing to occur in Viet Nam when it closed in October 2002. The total size of the project was US$480 million, of which US$340 million was debt. The debt was arranged by Société Générale Asia, ANZ, and Sumitomo-Mitsui Banking Corporation. The structure of the debt was rather classical for a project finance deal. Multilateral banks provided US$240 million of direct loans, with a 15-year tenor. JBIC of Japan lent US$150 million, France's Proparco lent US$40 million and the Asian Development Bank (ADB) provided a US$50 million direct loan. At the time, Phu My 2-2 was the largest involvement of Japan and France's export credit agencies in Viet Nam.

Commercial banks provided the remaining US$100 million. Due to the rather high perceived risk profile of Viet Nam, these loans needed to be at least partially guaranteed. The World Bank's International Development Agency (IDA) provided a US$75 million partial risk guarantee and the Asian Development Bank (ADB) partially guaranteed US$25 million under an arrangement with a private political risk insurer. The ADB's partial guarantee under an arrangement with a private risk insurer was a first.

Convincing multilaterals to guarantee the project proved to be a difficult task. France's political risk insurance agency Coface refused to guarantee the facility despite the fact that it was led by EDF. In the end, however, Phu My 2-2 reached financial close in a short time, and was named Deal of the Year by several publications

8.4.3 Reasons for Success

Several reasons can be found behind this success. The first one is the sound economics of the project; demand for electricity was and continues to be strong in Viet Nam, and the project managed to secure dedicated, low cost, natural gas. The strength of the commercial contracts is another positive feature of Phu My 2-2; the project has a long term gas supply commitment and a long-term power purchase agreement with two state utilities. Under the BOT agreement the Vietnamese government will gain ownership of the plant after 20 years. The project's private sponsors also proved important when it came to convincing investors; EDF, TEPCO, and Sumitomo are all investment grade entities with a proven track record in project finance and in developing power projects. Finally, the commitment of both the World Bank and the Vietnamese government to make this project happen helped secure the guarantees to finance the project.

Phu-My 2-2 has also had a strong legacy, and became the example to follow for other project finance deals in Viet Nam, including a similar power project named Phu My 3. Phu My 2-2 is also a welcome addition to Viet Nam's power grid; it is estimated that the new plant provides 8% of the economy's demand for electricity, a demand that keeps growing as the economy continues to industrialize. The project helps alleviate power shortages in the economy, an important step towards its sustained development and poverty alleviation.

9 POLICY MEASURES TO FACILITATE THE EXPANSION OF NATURAL GAS USE IN DEVELOPING APEC ECONOMIES

9.1 Introduction – A Tradition of State Monopolies

If a state-owned enterprise (SOE) enjoys a monopoly over a particular economic activity, whether it is a railway system, a power system, or gas supply system, the government will be concerned not only that the monopoly will operate in the public interest, but that it will perform with optimal economic efficiency so that, at the least, it will not impose an undue financial drain on the state.

Increasingly, however, governments are expressing concerns about the economic efficiency of their state-owned monopolies. One specific concern may be cross-subsidization between customers. For example, households might be paying unjustifiably high prices compared with industrial customers.

The existence of a monopoly may also have the effect of preventing competition either in the upstream (production) activities or in the downstream (distribution) activities. If entry to the market remains closed to potential competitors, there is no exposure to the forces of competition. Without exposure to competition, the management of an SOE will tend to wait for political directions rather than pursue the most efficient and profitable course of action.

Optimizing the economic efficiency of an SOE therefore poses special challenges. A government has three broad options available to address its concerns:

9.1.1 Option 1: Retention of the Monopoly

The first broad option is to retain the monopoly intact under state ownership and impose stringent regulatory controls over it to eliminate cross-subsidization and to prevent any misuse of control over access to the natural monopoly element. Increasingly, this option is falling out of favor with governments. Apart from other options seeming more economically efficient, it is very difficult for a government to judge the level of efficiency of a monopoly because of the difficulty of benchmarking its performance against comparable organizations.[60]

9.1.2 Option 2: Divestiture of the Monopoly

The second broad option for a government is to divest itself of the monopoly or of a stake in it. However, this often carries the risk that significant efficiency benefits will not be achieved unless appropriate regulatory reforms are carried out before the privatization.

[60] This is not to suggest that it is impossible for a state-owned monopoly, like a private sector monopoly, to be economically efficient. In theory at least, a monopoly can achieve efficiency by avoiding the transaction costs which are incurred by a multiplicity of rival, independent players competing against each other in an open market situation.

Without regulatory reforms, the government may be likely to attract a higher sale price. However, this could be at the expense of entrenching an uncompetitive monopolistic structure in private hands.

At the other end of the divestiture spectrum is the risk of maintaining an excessively heavy-handed regulatory regime and the risk of selling at too much of a discount. If a government makes regulation too heavy handed, or if it removes the protection of an SOE from competition altogether, this will mean not only lower profits for the SOE but a lower sale price for the government. Therefore, stability and evenhandedness in the regulatory regime are essential to attract buyers at the right price.

9.1.3 Option 3: Structural and Regulatory Reform

The third broad option for a government seeking to optimize the economic efficiency of a state-owned monopoly is to undertake comprehensive structural and regulatory reform. The structural reform of a monopoly necessitates the unbundling or disaggregating of the monopoly by separating the natural monopoly element from the potentially competitive activities. Private sector competitors can be invited to participate in the competitive activities when the government decides to proceed with privatization.

In such a case, not only will structural reforms be required to dismantle the state monopoly but regulatory reforms will also be required to ensure the contestability[61] of the market in the competitive activities and to safeguard the interests of consumers. The industry regulator should be independent of government. Both structural and regulatory reforms are prerequisites before competition can be achieved.[62]

Even where the legal barriers to entry in potentially competitive activities are removed, the natural monopoly element can prevent new entrants from competing on equal terms with existing service providers — preventing access to essential facilities, such as a pipeline. Laws enabling competitors to obtain access to such essential facilities are therefore required.

Irrespective of the stage of market development, the natural monopoly characteristics of the natural gas industry, particularly transmission and distribution, require some level of regulation. Table 9.1 sets out how the policy priorities will change as the market matures:

[61] Contestability is a term used in relation to a market to describe the ability of potential competitors to enter the market and to fight for customers.

[62] The case for structural and regulatory reform of monopolies is by no means confined to the public sector. Most market economies have competition laws designed to foster competition in industry by inter alia outlawing mergers and acquisitions which have the effect of reducing the level of competition in a market.

Exhibit 9.1: Change of Government Priorities with Maturity of the Gas Market

	Characteristics	**Role of Government**
Embryonic stage	Monopoly or few competitors No or little regulation framework No or little infrastructure Local and limited market	The government should be prepared to act both as investor and as regulator. Most of the projects are not self-supporting and need some help especially in financing and regulation. The potential investors are looking for some reward for taking risks, investing money and expect a fair return and a secure pay-back period. In some cases, due to the lack of private investors, the government would have to be the first investor.
Growth stage	High return on the projects Increasing private and foreign investment Clear regulation Price regulation Development of infrastructure Regional market	Foreign and/or private investors are attracted and consider a commitment in the development of the gas industry. The result is that the government is expected to promote a clear pricing structure that allows transparent pricing and competition.
Maturity stage	Intense competition Fewer projects Decreasing rate of return Strong competition	The government will look for increasing competition and a decrease in prices. It will foster and encourage competition and will look to improve end-user benefits. The trend is that monopolies are tending to disappear, profiting direct competition.
Decontrolled stage	Deregulation Narrow price margins Market segmentation	No government intervention is needed. The industry and end-users are mainly expecting that the market operates fairly and that the competition is not distorted. The market is free.

9.2 Policy Priorities for Expansion of Natural Gas Use

Four policy priorities are central to the expansion of natural gas use in developing APEC economies:

9.2.1 Affordability

The gas industry must be able to supply consumers with gas at prices they can afford, unless the government is willing to subsidize gas supply on an economy-wide basis.

9.2.2 Supply Security

For this policy priority, the creation of a stable and attractive environment to induce private investment is necessary for the long-term development of an adequate supply of natural gas.

9.2.3 Promotion of Competition

For this policy priority, the promotion of competition is the means for enhancing benefits to the consumer and achieving efficient resource allocation.

Ultimately, the desired outcome is to reach a point where market forces provide the signals and incentives for investment in resource exploration and development.

Developing economies with emerging natural gas markets face a dilemma in deciding which factor is to receive emphasis at the outset. The decision is largely dependent upon the answers to the following questions:

- Who are the gas customers (high-volume, industrial end users or small-load commercial and residential)?
- What is the extent and condition of pipeline network and other facilities that make up the infrastructure for the gas sector?
- Where does the gas supply come from (domestic or imported)?
- How much is the burner-tip price for competing alternative fuels?

The regulatory regime can also provide incentives for natural gas use such as allowing for long-contract development periods, long-purchase commitments, oil-equivalent pricing, and payment guarantees. Allowing access by third parties to production facilities pipelines and storage facilities for gas liquids can reduce development costs and provide market access.

Natural gas competes with other fuels in the end-user market and is priced according to market value (“market-based pricing”). Cross-border gas trade, if allowed, will increase gas-to-gas competition.

Policy towards cross-border gas trade tends to be sensitive to the stability of supply.[63] Importing economies look to imported natural gas to supplement or provide domestic supply. Exporting economies have generally determined that they have sufficient reserves both to meet domestic requirements and to supply export markets.

9.2.4 Attraction of Private Investment

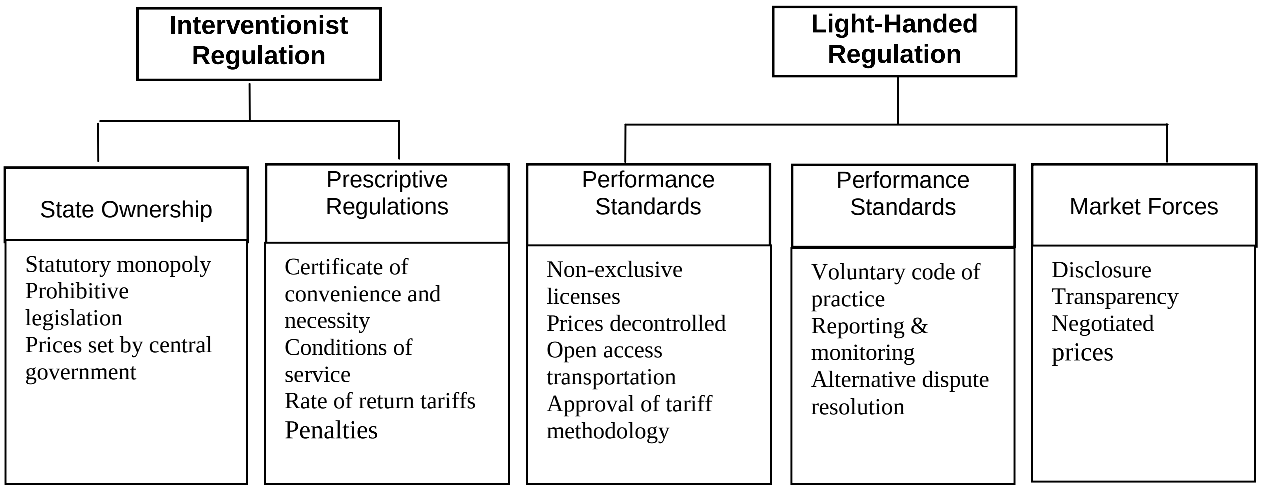
A growing economy is almost always the first thing that investors look for when developing a project. Private capital is of course attracted by the opportunity of doing business profitably. This requires the government to provide incentives to invest, to ensure the security and stability of the investment climate, and to provide safeguards against intervention.

9.3 The Regulatory Role of the Government

The main role of government is to set the conditions under which markets can operate with minimal supervision.

Two common regulatory philosophies and their features are depicted in table 9.2 below. In terms of actual practice, regulatory policies often fall somewhere between these two philosophies.

Exhibit 9.2: Common Regulatory Philosophies



Regulations can be promulgated to correct for market imperfections and to reduce uncertainty for investment. Regulations in the gas industry primarily focus on:

[63] Japan and Korea import over 95% of their natural gas which is mainly supplied by other APEC economies (Australia, Brunei Darussalam Darussalam, Indonesia, and Malaysia) as well as from outside the region (Qatar).

- **Technical standards,** implemented through licenses, permits, and codes.
- **Control of entry criteria,** implemented through licenses and permits. Licenses can either be exclusive or non-exclusive. Exclusive licenses can be awarded via public tendering or similar process to ensure the public interest is protected.
- **Economic issues**, such as prices, return on investment, and access to transportation-related facilities, implemented by tariffs and unbundling of transportation from the sale of gas as a commodity.
- **Taxation**, implemented by rules defining assessable income and limits for deductions. The domestic use of natural gas can be heavily influenced by incentives in the fiscal regime.

9.3.1 Technical Standards

Regulations in the gas sector must lay down the technical specifications for construction and maintenance, gas-quality specifications, environmental protection, land access, and limitations on flaring or venting of gas.

9.3.2 Regulation of Entry

The primary purpose in regulating entry into the gas industry is to ensure that owners and operators of pipelines and LNG terminals have adequate operational qualifications and financial resources. This type of regulation also allows the government to facilitate the coordination of investments within the gas industry, as well as related sectors, such as power generation, and to avoid creating redundant capacity and 'stranded assets'. Pipeline permits are issued by a regulatory authority following a review of the pipeline route, market requirements, engineering design, and environmental impact. The license may be exclusive or non-exclusive depending upon the level of competition for the right to serve a market.[64] Competitive bidding may be desirable.[65] Regulation of entry has been used to create statutory monopolies by awarding exclusive franchises and concessions, or by restricting entry to state-owned enterprises.

9.3.3 Economic Regulation

The approach taken for economic regulation is often more complex because a gas user pays for two components:

- the energy or 'commodity' value of the gas, and
- the cost of storing and transporting the gas by pipeline from the source of supply.

[64] Practices vary from Japan where licenses are granted for 20 years to New Zealand which has abolished geographical exclusivity.

[65] See for example Article 40 Mexico Natural Gas Reglamento (Nov. 1995).

Economic regulation is principally used as a means to limit the market power that is characteristic of the natural monopolies found in the gas sector. In the gas sector, market power typically arises from the vertical integration of the sale of gas, as a commodity, with transmission and distribution (the "gas merchant pipeline").

Owing to the capital-intensive nature of the gas industry, economic regulation that sets the rate of return that is allowable on qualifying assets has also been used. Selection of a particular tariff design primarily depends upon whether the return on the pipeline owner's equity is subject to performance risk if throughput declines over time. Regulatory intervention attempts to promote economic efficiency by applying the Cost of Service model, which sets tariffs such that total revenue is equal to total average cost.

The Value of Service tariff is the deregulation alternative to Cost of Service and is based upon charging what the market will bear. This approach is best suited to a commercial environment where the parties have equal bargaining power or where there are competing alternative fuels. The level of the tariff is settled by arm's length negotiation between the users and the pipeline owner. If the pipeline supplying the natural gas has a monopoly position in the market, the tariff may not achieve an outcome that is economically efficient.

Gas sector reforms have been implemented in various forms depending upon the specific circumstances in each economy. For example, in the United States, the regulator for interstate gas sales adopted a series of regulations that allowed gas producers to arrange for pipeline transmission to direct-market to end-users on the condition that the producers release the pipelines from claims for take-or-pay under long-term supply contracts.[66] Access to gas pipelines and production-related facilities in the United Kingdom resulted from concerns about the monopoly power of a gas merchant pipeline company.[67]

The most common regulatory tool for dealing with natural gas prices is to impose controls on the price at the point of sale (wellhead, city gate, or burner tip). International experience has shown this form of intervention has often led to under-investment in resource development as well as in infrastructure and has resulted in reduced supply. For example, producer prices in the United States were subject to different prices depending upon whether it was 'old' or 'new' gas.[68] It was considered to be unnecessary

[66] Federal Energy Regulatory Commission, Orders 380, 436, 500 and 636. The FERC Orders were subject to a series of appeals before the D.C. Circuit Court of Appeals, American Gas Assn. v. FERC 824 F.2d 981; 888 F.2d 136; 893 F.2d 349; 912 F.2d 1496 which upheld the majority of the rule-making.

[67] Monopolies and Mergers Commission, 1993, "Report on British Gas Under the Gas Act 1986".

[68] *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968).

to extend the higher price to old gas because the reserves had been developed at a time of lower cost, and the higher price would confer a windfall on such producers.

In economies where prices have been subject to rate-making practices applied to public utilities, rate-regulated natural gas companies must engage in complex and lengthy proceedings to determine the Cost of Service tariff that could be charged to obtain an acceptable rate of return. In other economies, the price of gas was set by the central government with differentials depending upon whether the end-use was for power generation, agricultural applications or commercial purposes.

A number of economies have introduced gas industry reforms that have stressed elimination of price controls on gas in combination with new rules for access to so-called “essential facilities”.[69] This approach is referred to as “unbundling”. In its most basic form, unbundling means that the commodity price of gas is quoted separately from the cost of transmission.

Gas prices may be fully deregulated or only regulated for commercial and residential customers who lack the bargaining power to deal with producers and transporters on an equal level. Other regulators set maximum prices only. In more extreme applications, pipeline ownership is divorced from gas production and marketing by regulation. The approach taken in a specific economy must take into consideration such factors as the maturity of the gas sector, as reflected by market penetration and extent of infrastructure, as well as the existence of long-term commercial and financial obligations.

In some APEC economies, domestic gas prices are mandated by government, which may reflect subsidies for agriculture, domestic use, and regional development. At APEC workshops in Tokyo and Singapore in 2004, the preference for economies to adopt market-based energy prices and then to use a system of rebates as the policy mechanism for adjustment was suggested as best practice.[70]

Regulators have adopted market-sensitive tariffs to allow wholesalers to purchase gas without having to file a new rate case when gas prices change. Similarly, power generators have been given permission to pass through increased gas costs under fuel cost adjustment provisions in their tariffs.

9.4 The Fiscal Regime

9.4.1 Domestic Projects

Like other commercial sectors, the natural gas industry is subject to the imposition of taxes on company income and shareholder dividends. Corporate tax rates can vary substantially, making business

[69] OECD, 1994, Natural Gas Transmission: Organization and Regulation

[70] ResourcesLaw International, "Great Expectations Cross-Border Natural Gas Trade in APEC Economies", APEC Secretariat, Singapore, see appendices 2 and 3.

structures important in determining ‘tax domicile’. Many countries have adopted income tax provisions specifically for the petroleum industry that provide for accelerated write off of development expenditures or depletion allowances for both domestic and foreign oil and gas.

Further liberalization and adjustment to the taxing of energy projects is required, in particular when complex joint ventures are established for different parts of an energy project and the ability of proponents to efficiently structure or restructure their projects is hampered by inflexible tax laws.

The facilities and infrastructure required for efficient and reliable production and marketing of natural gas are supported by complex contractual and financing provisions that specify delivery rates and mechanisms for price adjustment for many years into the future. These provisions, such as take-or-pay obligations, can have tax implications as well.[71]

In a world of higher energy prices, gas exporters can be faced with a potential dilemma of higher netback prices for export gas over those available in the domestic market. Whilst this may not be a problem in economies where the government controls or owns the energy-producing assets, a free-market environment will see the resource developer striving to secure the highest returns for its shareholders.

Gas sales and transportation arrangements also attract excise taxes on the sale of goods and services. As a general rule, taxes should be imposed as close as possible to the point of final use so that consumers are aware of the true cost of supply. Determining tax jurisdiction where the point of sale occurs can have significant tax consequences. Some countries also have special levies that are paid on natural gas.

9.4.2 Cross-Border Projects

Harmonizing fiscal regimes primarily requires a single method for assessing income and capital allowances. It is preferable to grant the project exemptions from excise taxes, withholding taxes on dividends, customs duties, and transit fees. Often these issues are dealt with in bilateral investment treaties.

Once the fiscal regime is established, there are three variations for apportioning tax revenues from cross-border gas projects where there are facilities located in more than one economy:

- the value of facilities or length of pipeline located in each economy,
- the quantity of natural gas delivered in each economy, or

[71] For example, take-or-pay payments made by a gas purchaser are usually treated as a deferred charge that is only included in the purchaser’s cost of gas when it is made up. If the gas is never taken and the take-or-pay payment is not refunded, the amount is allowable as a loss in the tax year that it was determined it was not possible to make-up by delivery.

- some combination of these two.

9.5 Policy Measures for Consideration by APEC Economies

9.5.1 The Need for Effective, Stable and Fair Regulation

It is important that the regulatory regime for the natural gas industry distinguish between the commercial functions of the government, either as a participant or beneficiary in profit-sharing from the sale of gas, and its other functions in allocating the right to develop gas resources and as regulator of the industry.[72] Before establishing an independent regulatory body for natural gas, some economies have relied on the line agency or ministry that has policy responsibility for energy. Often the department or bureau responsible for natural gas oversight is not independent from the line ministry that is responsible for promoting investment in upstream operations or the national oil company.[73]

In the longer term, each economy will need to establish an effective, stable, and fair scheme of independent regulation. The role of government is to design and put in place the regulatory scheme; the role of the regulator is to implement it. The regulator does not, or certainly should not, make its own regulatory rules. Some principles of effective regulation are set out in Exhibit 9.3.[74]

Exhibit 9.3: Principles of Effective Regulation

The regulator should be legally and organizationally separate from the government and the utilities
The objectives of the regulator should be specified in clear and unambiguous terms
The scope for the regulator to exercise personal discretion should be limited (to maintain confidence in the impartiality of the regulatory process)
Regulatory procedures should be transparent and easy to administer
Regulatory procedures should be carried out promptly
A method of review of network pricing should be specified which enables network operators to benefit from efficiency improvements and which leads to simple, automatic adjustments

[72] The World Bank, 1995, "Legislative Framework Used to Foster Petroleum Development", Policy Research Working Paper 1420.

[73] Several APEC economies have their energy or related ministries performing gas regulatory functions. In Thailand, the Energy Policy and Planning Office (EPPO) regulates pipeline tariffs and rates of return from gas supply and distribution. In the Philippines, upstream petroleum operations and pipeline licensing is within the Department of Energy. In Malaysia, the Department of Electricity and Gas Supply, under the Ministry of Energy, Communications and Multimedia, regulates the natural gas industry. In Viet Nam, the Prime Minister's Office sets prices for natural gas while the Ministry of Trade and Tourism directly controls the state entity responsible for the distribution system.

[74] Taken from Pritchard, R and Webb, D, "Privatization and Private Provision of Infrastructure", chapter 4 in Pritchard, R (ed), 1996, "Economic Development, Foreign Investment and the Law", International Bar Association and Kluwer Law International, London, UK.

The regulator should be able to obtain direct access to information about service quality and user satisfaction, with mechanisms to consult with the public
The regulatory system should function free from political interference
The regulator should be legally accountable for its actions by a prompt and effective appeal process

Independence of the regulator, both from the government and the regulated entities, is a crucial issue. Without independence, conflicts of interest are likely to arise and the stability and fairness of regulation is prone to deteriorate. At the same time, the regulator must be held legally accountable for its actions; regulatory independence and accountability must go hand in hand.

There are two broad options by which the establishment of an effective regulatory scheme can be achieved: the first is by the enactment of legislation to establish an independent regulatory scheme applicable to the entire industry; the second is "regulation by contract", that is, by the negotiation of contractual regulatory arrangements with the energy facility operator on an individual basis.

For governments in economies which are not accustomed to independent regulatory systems, it may be more palatable for political reasons for regulatory controls to be negotiated and set out in particular contractual arrangements. These may be easier for some governments to implement than the establishment of an independent regulatory agency at the outset and may be seen by investors as offering more certainty, security and stability for their investment. Such contractual arrangements must, however, be enforceable against governments.

In the longer term, there is an absolute need to avoid regulatory policies that do not reflect the current environment in the industry and therefore discourage new capacity, competition, market entrants, efficiency gains, and carbon-intensity reductions and other advances.

9.5.2 Regulation of Natural Gas Imports

Cross-border natural gas can become subject to two masters when importing countries also regulate this trade. Regulators in the importing economy have required evidence of competitive pricing, market demand, and security of supply before granting approval. The trend is for a light-handed approach that allows imported gas to be judged on its economic merits in competition with domestic supplies.[75]

[75] In Mexico, imported natural gas is exempt from price regulation under Article 8 of the Natural Gas Reglamento (Nov. 1995).

9.5.3 Regulation of Natural Gas Exports

Regulation of gas exports has taken several forms. In those economies that have adopted production sharing contracts (PSCs), the contractor typically has the right to ". . . lift, dispose of and export its share of petroleum production . . ." Unless the host government has enacted legislation that regulates natural gas exports, this contractual provision is sufficient authority for cross-border natural gas trade.

Other exporting economies have taken a formulaic approach where exports could only be sanctioned when either the level of gas reserves or the capacity to deliver gas to the domestic market had been satisfied.[76] Papua New Guinea requires either a ministerial instrument or agreement with the state before natural gas can be exported.

9.5.4 Cross-Border Regulatory Harmonization

Regulatory harmonization does not mean that each economy involved with the project, whether as exporting, importing or transit nation, will adopt a uniform or standardized regulatory regime. Rather, to the extent possible, it is a commitment to provide a regime that is simple, transparent, and that supports the natural gas industry's commercial and financial structure. The goal of harmonization is to remove the uncertainty of local law and regulatory regimes. Within such a framework, the project sponsors can structure a project entity that facilitates financing.

The process of regulatory harmonization is dependent upon the legal, commercial and cultural similarities of the exporting and importing countries. Possible approaches include:

- multiparty project agreements between the respective governments and the commercial sponsors,
- project-specific agreements or framework treaties between sovereign states, and
- special purpose enabling legislation and regulations.

A combination of the above approaches could be necessary where there are serious political and commercial risks.[77]

[76] For example, until 1986 the National Energy Board of Canada conditioned gas exports on the "Reserves Test of Formula" and the "Deliverability Test of Appraisal" when a market-based procedure was for granting export licenses. A similar situation has been evident in Bangladesh.

[77] For example, the legal framework for the West African Gas Pipeline Project involving Benin, Ghana, Nigeria, and Togo includes an international project agreement between the states and the commercial group of companies, a treaty between the governments and harmonizing legislation as well as an administrative body specifically created to regulate the project on behalf of the states.

9.5.5 Multi-Party Project Agreements

Multi-party project agreements have been used successfully to promote cross-border natural gas trades. Typically, they are used where the natural gas is transported by pipeline and have tended to recognize the right of the respective states to assert regulatory authority over the portion of the pipeline system that is within their jurisdiction rather than adopt uniform rules.[78]

Regional trade agreements have also served as platforms for securing access to both supplies and markets. In terms of regulatory harmonization, the signatory states agree to limit regulatory measures that discriminate in favor of its nationals, restrictions on imports and exports and export taxes.[79] Specific directives on natural gas transportation have been issued under these trade agreements.[80]

Multi-party project agreements also raise concerns about the extent that the respective governments are willing to give undertakings regarding:

- waiver of sovereign immunity,
- whether foreign law will control the interpretation of the agreement,
- performance guarantees and credit support for state-owned enterprises, and
- consent to participate in and be bound by international arbitration and dispute resolution procedures rather than invoking the jurisdiction of its courts.

9.5.6 Investment Agreements

Some APEC economies have had experience as host governments in contracting directly with international oil companies through exploration and production investment agreements.[81] Often these agreements contain so-called ‘gas clauses’ that provide for negotiation of supplemental agreements if natural gas rather than oil is discovered. A contractual approach is particularly useful where there are either major gaps in domestic law or fundamental differences in legal systems. There have also been a substantial number of international arbitrations concerning the interpretation and enforcement of such contracts which support the credibility of using a contractual approach to regulation.

[78] For example, the Agreement Between The United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline (Sept. 20, 1977; June 6, 1978).

[79] North American Free Trade Agreement (NAFTA), Art. 606 – Energy Regulatory Matters.

[80] Directive on the Transit of Natural Gas Through Grids, Council Directive No. 91/296 EEC (31 May 1991)

[81] Production sharing contracts, service contracts and petroleum agreements are examples of such contracts.

9.5.7 Special Legislation

Special legislation may be necessary when contracts and trade agreements are not sufficiently robust for the project participants and their financial backers.[82] Regulatory exemptions, waivers of law, and tax holidays have also been used to underwrite governmental support for cross-border gas projects.

9.6 Summary and Conclusions

In many APEC developing economies, SOEs have enjoyed a monopoly over the local gas supply system. In the short term, this may mean that the importing gas monopoly has the creditworthiness and other credentials to qualify it to enter into a long-term SPA with a natural gas supplier.

However, monopolies are not always economically efficient as they are not exposed to the forces of competition. Unless a monopolist wants to deal with a new gas supplier, there may be no way for the new supplier to enter the local market. There is a need for governments to consider the policy and regulatory options on an economy-specific basis as the local market matures.

[82] For example, special legislation was passed in Canada (Northern Pipeline Act 1978) and the United States (Alaska Natural Gas Transportation Act 1976) to facilitate the Alaska Natural Gas Pipeline Project.

10 SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

10.1 Importance of Natural Gas in APEC's Energy Mix

Natural gas already represents a major energy source in a number of the APEC economies. Some of the economies, such as Japan, Korea, Malaysia, Russia and Thailand, are already heavily dependent on natural gas for energy production and industrial use. Most of the developing APEC economies have tended to rely more on coal for their energy needs, as coal is the more abundant domestic resource (China in particular). In some other economies, natural gas has only recently been discovered (Peru, the Philippines, and Viet Nam).

Natural gas is the fastest growing energy source globally, and the APEC economies are expected to be an important part of this growth. While some industrialized APEC economies, such as Japan, Korea, Chinese Taipei, and Thailand, may only experience limited growth because their natural gas markets are already mature, other APEC economies will be strong drivers in the growth of the global natural gas market. The United States is currently considering and building numerous LNG regasification terminals for power generation and industrial use as is China, which is also building LNG terminals in an effort to keep up with booming domestic electricity demand. Smaller economies, such as Peru and Viet Nam, are expected to develop their natural gas reserves and become both natural gas consumers and exporters.

10.2 Advantages of Natural Gas for APEC Economies: Economic Development and Environmental and Energy Security Advantages

For APEC developing economies with natural gas reserves, exporting gas can be an important part of their economic development strategy. Brunei Darussalam provides a successful example, and Papua New Guinea could follow in its footsteps.

The high number of new natural gas projects in the APEC economies also reflects the growing importance of natural gas as an environmentally friendly energy source. A key driver behind the increasing use of natural gas for power generation, in the light of the Kyoto protocol and other initiatives, is to reduce carbon emissions.

Natural gas is also an important consideration in addressing the energy security issues of the APEC economies. For those economies in which natural gas represents only a low percentage of the overall domestic energy mix, increasing the use of natural gas is a way to diversify away from other fossil fuels, such as coal and oil. This is particularly so in China and the Philippines. For economies where natural gas reserves have been discovered, such as Peru and Viet Nam, developing natural gas is another way to reduce the dependency on foreign energy imports.

10.3 The Threshold Question: Proximate Location of Resources

Always the threshold consideration in introducing or increasing the use of natural gas in any economy is whether natural gas resources are located in proximity to centers of potential demand. If indigenous resources are located near a population center, the cost of field development and installation of pipelines and other required infrastructure may justify early development of the gas resources. By contrast, if the indigenous resources are located in a remote location, separated from population centers by natural barriers, such as rivers or mountains, or in offshore coastal waters, the cost of field development and construction of transportation infrastructure will represent a far greater challenge.

If an economy has coal resources, coal bed methane (CBM) and/or coal mine methane (CMM) may also be an alternative resource that can be developed. Both CBM and CMM have considerable untapped potential in many APEC economies, but the accompanying enabling regulatory framework is often not developed.

Natural gas utilization poses a challenge of a far greater order of magnitude and complexity if there are insufficient indigenous resources and natural gas must be imported from abroad. Apart from the challenge of project scale, transportation costs will constitute an increasing proportion of the ultimate cost of natural gas, whether imports are procured by pipeline or by conversion to LNG and shipment to an LNG receiving terminal in the importing economy. In addition, the complexities associated with cross-border trade raise many policy, legal, and commercial issues that need to be dealt with.

10.4 Financial Support

Institutional support for projects is required, which could be provided by the host governments by way of limited recourse underwriting or support, through to agencies, such as the World Bank, Asian Development Bank and other multilateral agencies, providing various forms of project finance, aid, or guarantees to enable their completion.

10.5 Recommendations to Develop the Natural Gas Sector in Developing APEC Economies

Most of the developing APEC economies could increase their usage of natural gas. The threshold consideration is really about affordability; there must be a certain critical mass of consumer demand or potential demand that will justify the high initial capital cost of installing the required infrastructure to bring the gas to market. In encouraging investment in natural gas development, governments need to introduce a favorable regulatory environment, at the same time providing a sense of security for investors and incentives to invest. For example, they can provide fiscal incentives to power producers to encourage them to switch their fuel use from coal. Similar incentives can be devised on a smaller scale to encourage the use of natural gas for public transportation.

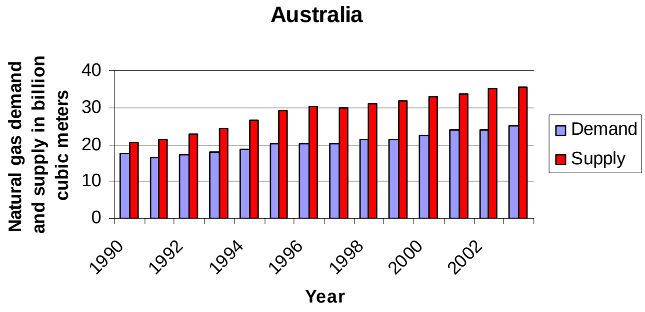
Governments should help with the collection of reliable data on natural gas demand and potential future demand. The governments also have an important role in spreading information on natural gas among their communities. One of the reasons some LNG terminal projects have been abandoned by their sponsors in the United States was the opposition of local residents, opposition spurred by a lack of knowledge on the actual risks and benefits of LNG, for example.

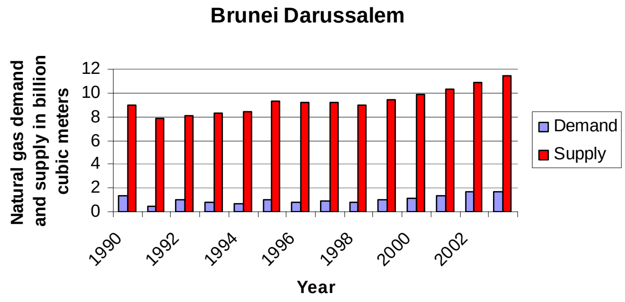
As a broad initial strategy, it is recommended that governments of all APEC developing economies should adopt a clearly articulated "industry vision" for the natural gas sector as part of their individual domestic energy policies. This will give comfort to potential investors about the future direction of industry and power generation development. Ad hoc government decisions tend to hamper market efficiency and impair the development of a strong natural gas sector. Aided by a clear and realistic industry vision, private investors can usually be counted on to respond to opportunities in the market.

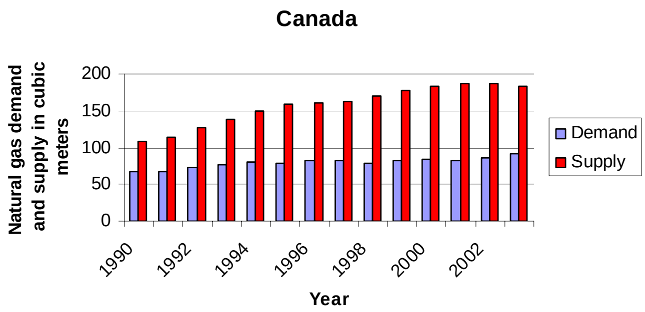
APPENDICES

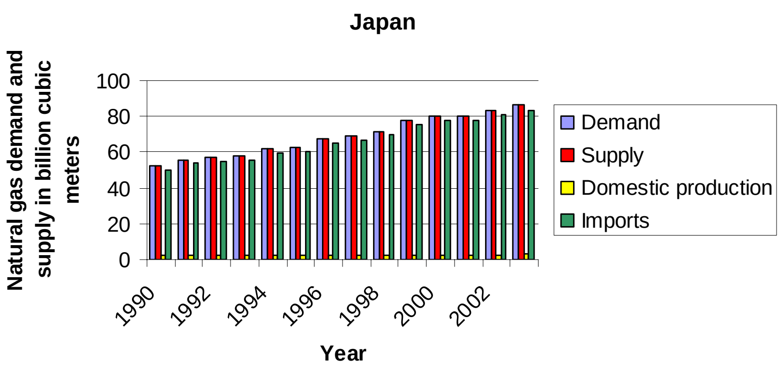
Appendix A

Natural Gas Demand and Supply in Industrialized APEC Economies Since 1990[83]



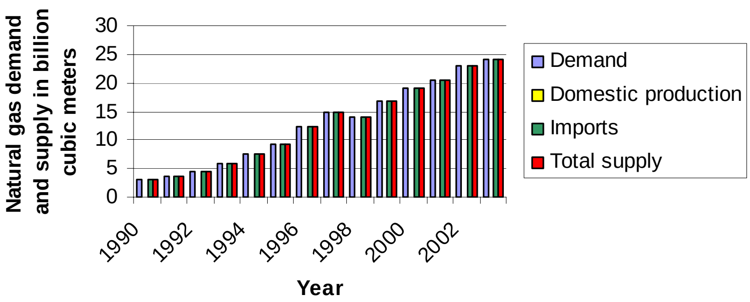




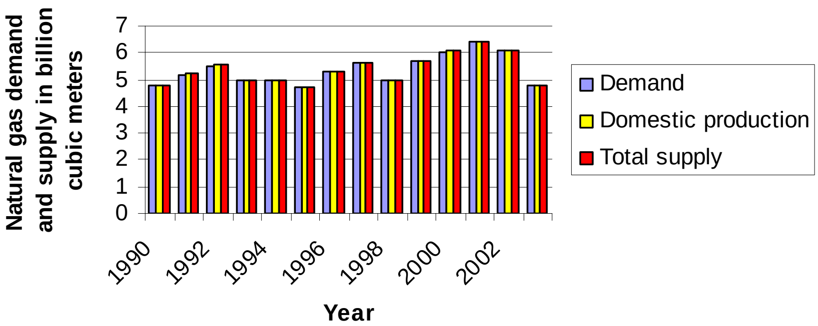


83 Demand is assumed to be equal to the total domestic consumption, and supply is the sum of domestic production and imports. The difference between supply and demand corresponds to exports. Data is from the EIA.

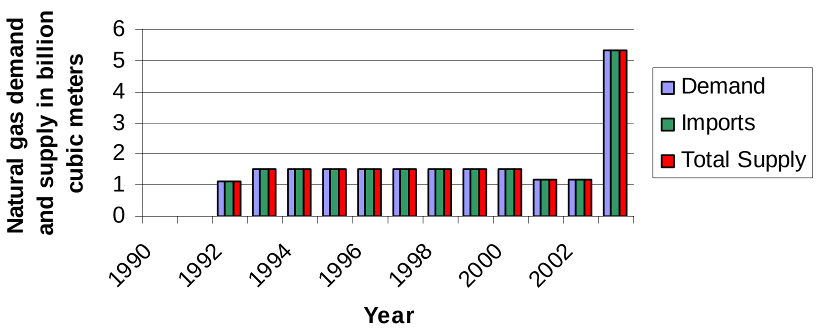
Korea



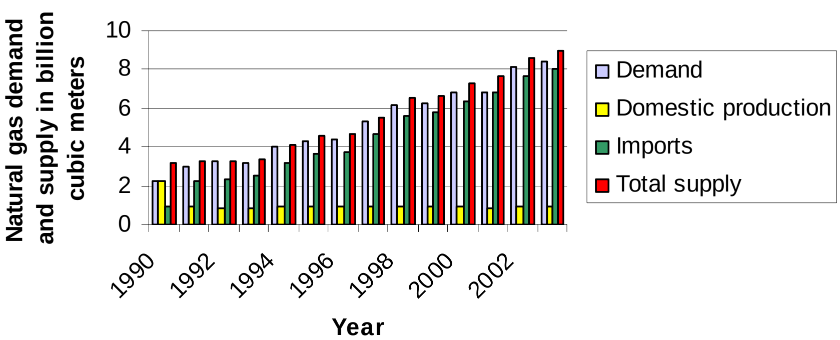
New Zealand

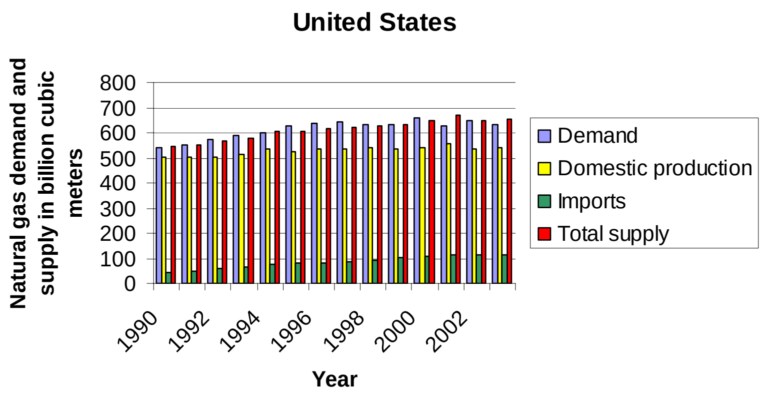


Singapore

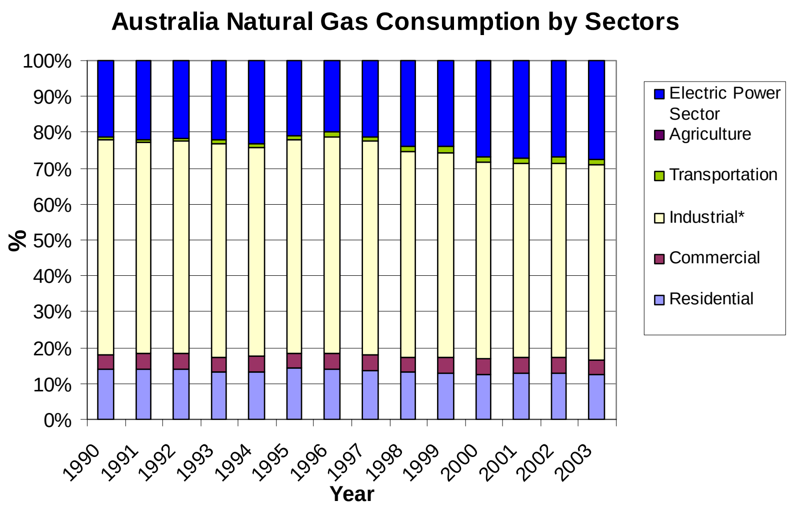


Chinese Taipei

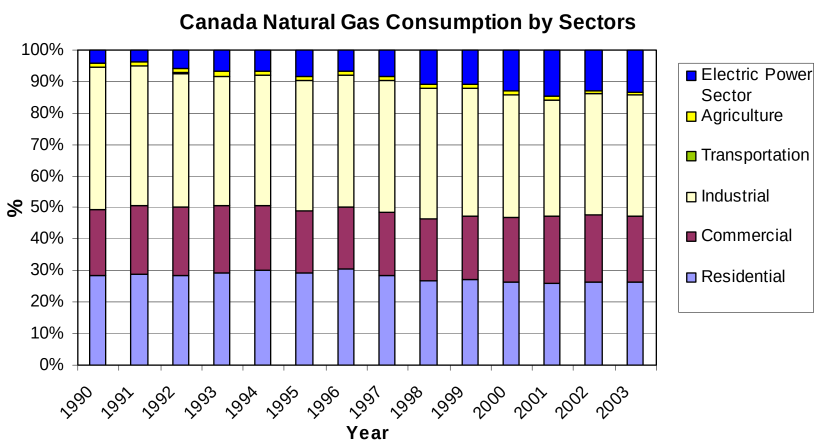




Breakdown of Natural Gas Usage by Sector Since 1990

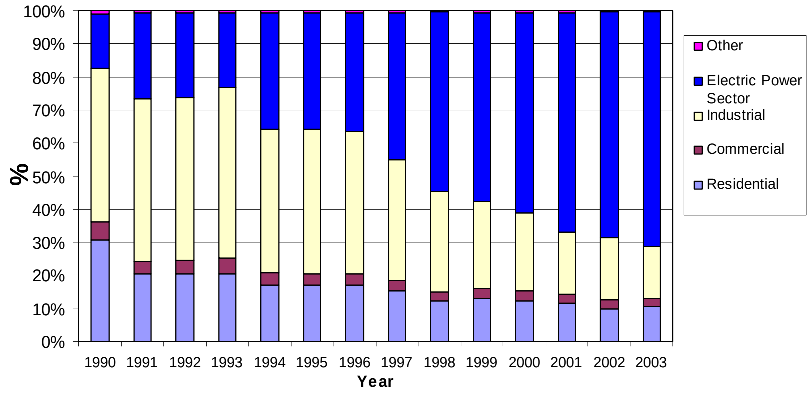


*Industrial=Mining + Manufacturing + Construction
Source: Australian Bureau of Agricultural and Resource Economics (ABARE)



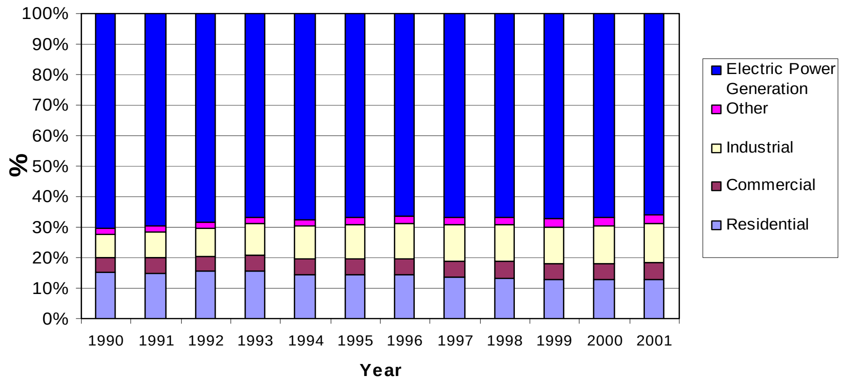
Source: Statistics Canada

Chinese Taipei Natural Gas Consumption by Sectors



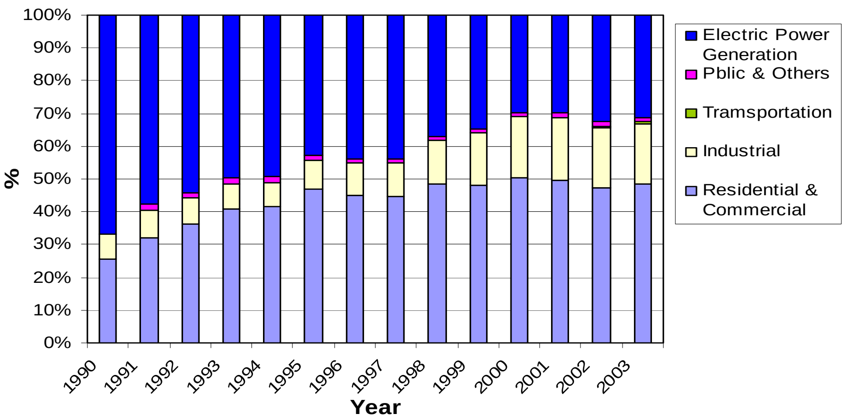
Source: Bureau of Energy, MOEA

Japan Natural Gas Consumption by Sectors

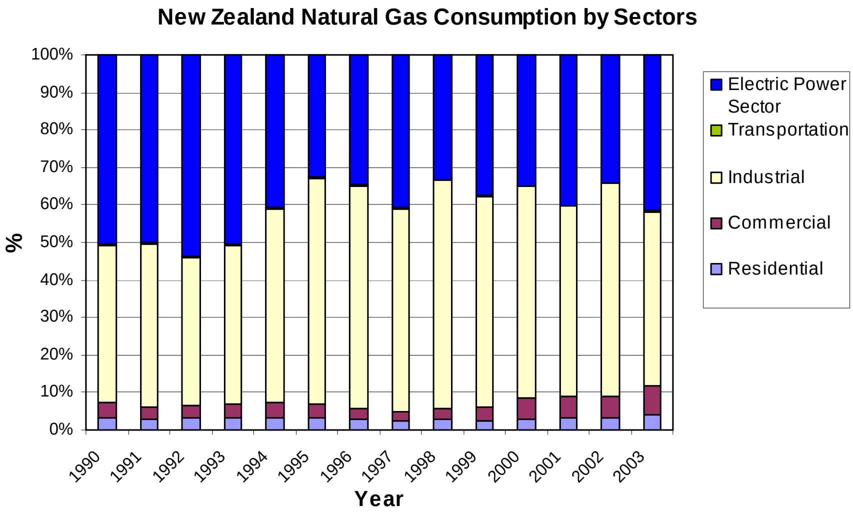


Source: Statistics Bureau & Statistical Research and Training Institute

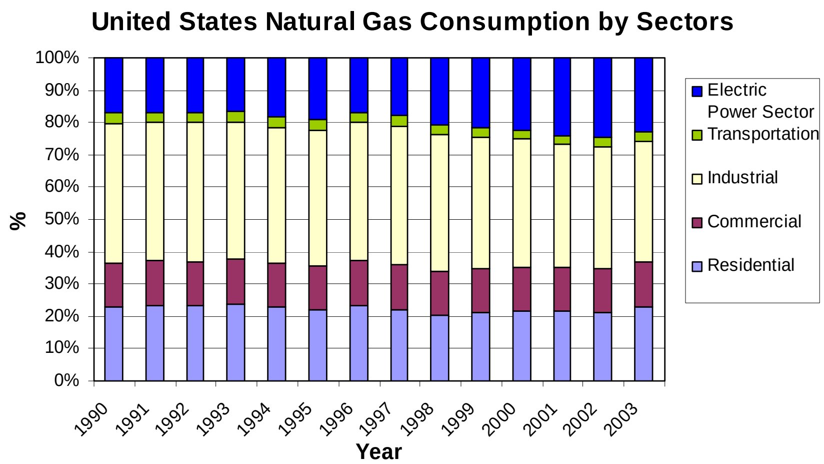
Korea Natural Gas Consumption by Sectors



Source: Korea Energy Economics Institute



Source: Ministry of Economic Development



Source: Energy Information Administration, USDOE

APPENDIX B

Review of the Natural Gas Sector in Developing APEC Economies

CHILE

Available Energy Resources

	Natural gas	**Oil**	**Coal**
Proven Reserves	99.1 bcm	150 mm bbls	1.3 bn short tons
Production	999.6 mmcm	18,400 bbls/d	0.5 mm short tons

Source: EIA - Country Analysis Brief, Chile

Chile is a net importer of oil and only has one oil-producing region within its borders: the Magellanes Basin. Chile's national oil company, Empresa Nacional de Petroleo (ENAP), has developed 23 oil fields in the basin. Exploration of other regions has proven unfruitful, and existing wells have matured; thus, production of oil in Chile is on the decline. Chile has three refineries, the largest being the Bio Bio refinery.

Chile's production of natural gas is minimal. Up until the late 1990s, its production was sufficient to fill domestic demand; however, severe drought in the latter part of the decade limited its hydroelectric generating capabilities. Frequent power shortages prompted the need for greater consumption of natural gas for power generation.

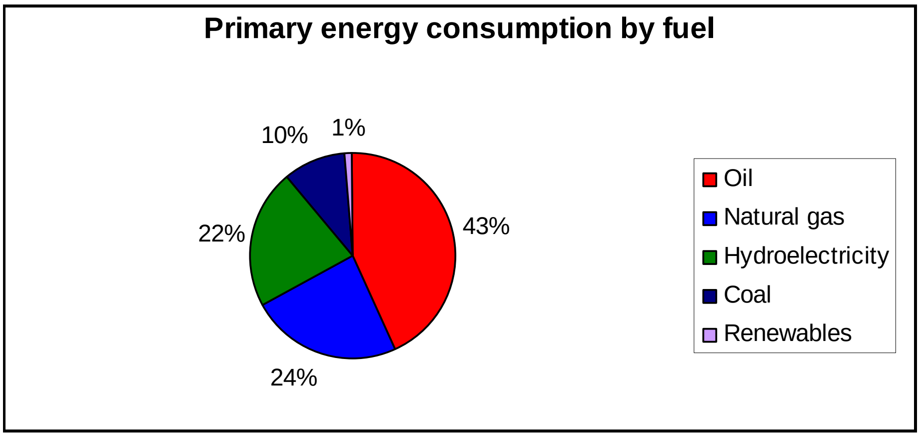
Chile's largest coal mine was closed in 1997, and the only two remaining mines are located in the far south of the economy on Tierra del Fuego. The coal is of low quality and expensive to produce. Production from the two mines is supported by coal imports.

In 2003, Chile had a total installed electricity generation capacity of 10.5 GW and produced 45.3 billion kilowatt-hours. Hydroelectricity supplied ~~of~~ 53% of Chile's total production in 2003, with thermal sources comprising another 43%.[84] Chile's installed thermal capacity is 0.4 megawatts-thermal and that produces roughly 7 terajoules per annum of direct-use heating.[85]

[84] EIA – Country Analysis Brief, Chile

[85] EIA – "An Energy Overview of Chile"

Current Energy Mix



Source: EIA - Country Analysis Brief, Chile

Since Chile began importing natural gas in 1997, consumption has increased 21.7% per year to 7.06 bcm.[86] In 2003, natural gas made up 23.7% of the economy's total energy consumption;[87] the goal of Chile's National Energy Commission (CNE) is to increase natural gas consumption as a portion of the economy's energy mix to 43% by 2020.[88]

Argentina is Chile's main source of natural gas imports. In 2004, Argentina suffered an energy crisis and cut natural gas exports to Chile. Since then, exports from Argentina have fluctuated between 20% and 50% below average,[89] and have sometimes ceased completely during specific periods. Productivity at power and methanol plants in Chile has declined due to shortages in gas supplies. Methanex owns three of the import pipelines that run from Argentina to Chile; those pipelines supply Methanex-owned methanol plants, the exports of which go to North America and Asia. While Chile is interested in receiving exports from Bolivia, political tension between the two economies makes an energy trading relationship elusive for the short term. Regional integration plans for the energy sector may soon make an energy partnership between the two possible. Argentina is also Chile's primary source of oil imports, followed by Brazil and Nigeria. Chile's coal imports come from Australia (33%), Indonesia (23%), Colombia (17%), and the United States (14%).[90]

---

[86] EIA – Country Analysis Brief, Chile

[87] *Ibid*

[88] EIA – "An Energy Overview of Chile"

[89] EIA – Country Analysis Brief, Chile

[90] *Ibid*

Energy Strategy

The over-arching goal of the Chilean government is to enter into an integration agreement with the other fuel-exporting economies in the region, particularly its immediate neighbors (Argentina, Peru, Brazil, and eventually Bolivia), and create an energy "ring" through which resources are shared. Several schemes have been put into motion to accomplish this, but the political tensions between Chile and Bolivia continue to limit such agreements. Chile is also promoting the development of an inter-connected electricity grid for the region, which would include cost-sharing on the construction of power plants and the harnessing of Chile's abundant hydroelectric power. The recent decision by Bolivia's government to nationalize its energy resources may prove a further hindrance to any energy integration plans. This move by Bolivia also seems to provide further justification for Chile's plan to construct an LNG terminal. Although LNG may not be the least expensive source of natural gas for the economy, it will be the most stable source of supply and will provide the economy with a degree of energy security that it has not had for some time.

Chile is interested in continuing to develop its gas-fired power plant capacity. By 2020, CNE aims to increase the proportion of natural gas in the economy's energy mix to 43%,[91] and has plans to develop 10 new combined-cycle gas-fired power plants in contrast to one new hydroelectric facility in its Central Interconnected System (SIC), which serves 93% of the domestic market. However, this goal may change if gas prices continue to remain high.

Energy Infrastructure

ENAP operates Chile's domestic natural gas distribution network of pipelines; this network runs from the Magellanes Basin to various population centers and there are seven natural gas import pipelines that run between Argentina and Chile. In total, the four northern and central pipelines cover 2,854 km and offer 34 million cubic meters/ day (Mcm/d) of transport capacity. Among these are the GasAndes and the 530 km Gasoducto del Pacifico pipelines. The 940 km GasAtacama pipeline is co-owned by Endesa-Chile and CMS (US). Tractebel (Belgium) and the Southern Company (U.S.) own the fourth pipeline, the Norandino, which has a capacity of 7.93 Mcm/d and supplies gas to Electroandina's power plant and other gas-fired power plants in the north of the economy. The other three pipelines supply Methanex plants.

Chile's state-owned oil company, ENAP, is the main supplier of the economy's energy. ENAP is responsible for production and importation of oil and natural gas, and fills over 40% of the economy's demand. In the northern and central regions, pipelines running from Argentina to Chile are owned by ENAP and CMS, Tractebel, TotalFinaElf, and a TransCanada/El Paso/Gasco partnership.

[91] EIA – "An Energy Overview of Chile"

CHINA

Available Energy Resources

	Natural gas	Oil	Coal
Proven Reserves	2.23 tcm	17.1 bn bbls	104.2 bn short tons
Production (2004)	40.8 bcm	3.5 mm bbls/d	1.8 bn short tons

Source: BP Statistical Review of World Energy 2005

According to BP's Statistical Review, China's proved oil reserves stood at 17.1 billion barrels at the end of 2004. The EIA[92] states that production capacity is around 3.6 million bbl/d and 85% of that capacity is located onshore. A large portion of this production comes from a single field; the Daqing field, located in the northeast of the economy, which produces approximately 900,000 bbl/d. Daqing is a mature field and production from this site has been declining. Much of China's new production is expected to come from fields in the western part of the economy. Developing the infrastructure to transport these resources to the population centers on the east coast has become a government priority. New production is also expected to come from the further development of offshore fields. The China National Offshore Oil Company (CNOOC) is the state-owned company responsible for offshore operations. The two other major state-owned oil companies are the China National Petroleum Corporation (CNPC) and the China Petrochemical Corporation (Sinopec).[93]

China's major gas fields are located in the western part of the economy, and again present the difficulty of transportation to eastern demand centers. CNPC recently completed the West-East pipeline, which runs from major gas fields in the Xinjiang region to Shanghai. The delivered price for power producers is reported to be about US$2.95/mmBtu, compared with an average price for coal of US$1.21/mmBtu.[94] Another important pipeline connects a major gas field in Inner Mongolia to Beijing. Demand in Beijing and its surrounding areas has already surpassed the pipeline's capacity, creating the possibility for construction of a second pipeline. Offshore gas fields in the East China Sea are currently at the center of a dispute between China and Japan over territorial rights.[95]

Coal is currently China's most plentiful fossil fuel resource and its most important source of energy. China accounts for over 28% of the world's total coal production. The economy's coal industry has been plagued by production issues involving unsafe mines. Transportation has also been an issue, as the railways used to transport coal are at capacity. Still, production has been rising since 2000, after slight

---

[92] EIA, *China Country Analysis Brief*, August 2005

[93] *Ibid*

[94] Miyamoto, Akira and Ishiguro, Chikako. *"Pricing and Demand for LNG in China: Consistency between LNG and Pipeline Gas in a Fast Growing Market"* Oxford Institute for Energy Studies, January 2006

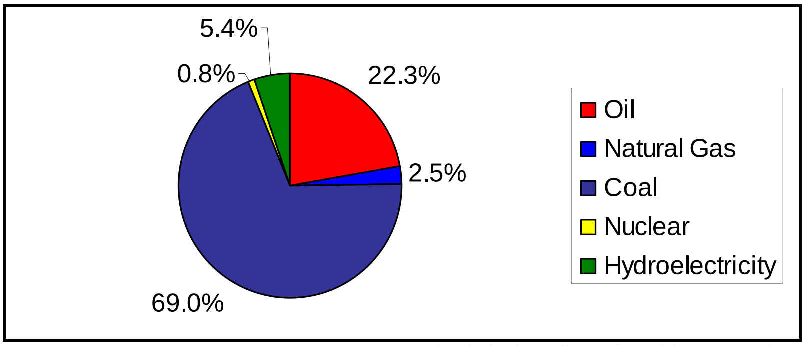
[95] *Ibid*

declines toward the end of the last decade. Going forward consumption of coal is expected to shrink as a percentage of overall energy consumption; however, absolute production numbers will continue to grow due to increasing overall demand.[96]

Current Energy Mix

The chart below illustrates the dominant role coal plays in China's primary energy mix, a dominance that is the result of coal's abundant domestic reserves. However, environmental concerns, transportation bottlenecks, increasing demand for gasoline as a transportation fuel and the relative inefficiency of coal as a feedstock for power generation will all combine to reduce coal's proportion of China's overall energy consumption in the future.

Primary Energy Consumption by Fuel



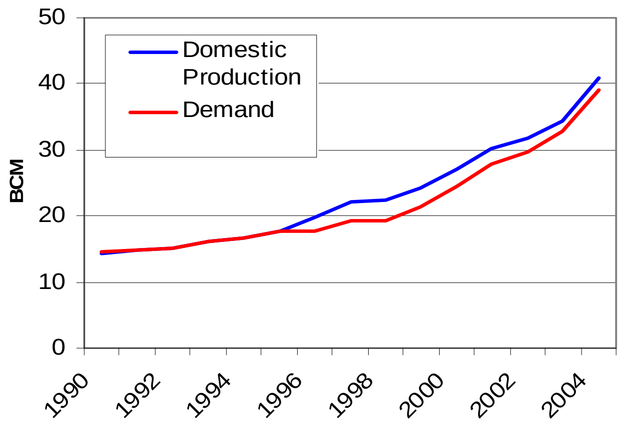
Source: BP Statistical Review of World Energy 2005

China's industry-led development model has made that sector the largest user of primary energy, accounting for 68% of total consumption.[97] An increasing standard of living is expected to drive a strong demand for automobiles and increase consumption in the transportation sector proportionally. In 2003, 1,807 billion kilowatt-hours of electricity was consumed with 15% generated by hydropower, just over 2% by nuclear power, and the remaining 83% by thermal power. Coal is, by far, the most important feedstock for power generation. However, concerns regarding coal's environmental impact have prompted government initiatives to increase the use of natural gas for power generation.

[96] *Ibid*

[97] China Energy Group

Natural Gas: Domestic Production and Demand[98]



As the above chart shows, over the last 15 years, China's domestic production of natural gas has kept pace with demand. However, the EIA predicts that consumption of natural gas will double by 2010 and a study by Japan's Institute of Energy Economics suggests that natural gas demand will make up over 9% of primary energy consumption by 2030.[99] This growth will be driven in large part by the increased use of gas for power generation, as well as increased residential consumption in urban areas. While some of the rising demand will be fulfilled through increases in domestic production, a large portion will come from pipeline imports and imported LNG.

Energy Strategy

The Chinese government's overall energy strategy has focused on securing the energy reserves needed for future growth while increasing the attention placed on environmental protection and energy efficiency. Increasing the role of natural gas in the economy's energy mix has been vital to meeting these objectives, as was evidenced by the government's 2001-2005 Five-Year Plan (FYP), which called for the doubling of domestic natural gas production and the construction of 14,500 km of gas pipeline.[100] Increasing the role of natural gas in power generation and in the supply of residential heating is also expected to reduce emissions of carbon dioxide, sulfur dioxide, and particulate matter that are produced from burning coal. Finally, China's most recent FYP (2006-2010) lays out a goal of reducing by 20% the amount of energy required to produce one unit of GDP. China currently has one of the worst energy efficiency ratios in the world, due in large part to its heavy reliance on coal, and increasing the use of natural gas as a primary energy source will help to improve energy efficiency.

[98] BP Statistical Review of World Energy 2005

[99] Li Zhidong, Ito Kokichi, and Komiyama Ryoichi. "Energy Demand and Supply Outlook in China for 2030." The Institute of Energy Economics, Japan. August, 2005.

[100] *Developing China's Natural Gas Market*. International Energy Agency. 2002, p. 78.

One of the keys to growing the role of natural gas in China's energy mix is development of the necessary infrastructure. However, currently the economy does not have a comprehensive regulatory framework governing the domestic downstream sector. Most of the regulation has been put in place by local authorities, and the effect has been a confusing mix of laws that fosters uncertainty and inefficiency. In this environment it is difficult to attract the investment necessary to underwrite the large amounts of capacity that will be necessary to realize the government's natural gas objectives. In response to this, the Chinese government, in collaboration with the World Bank, has been working to establish a more unified code that will establish a solid base for gas market development; however, progress has been slow.

Energy Infrastructure

The capacity of China's current natural gas infrastructure is insufficient to meet projected growth in domestic demand. The economy's domestic gas fields are located to the north and west, while much of the increased demand will take place on the southeastern coast, necessitating the development of long inter-province pipelines. Secondly, even if the domestic transmission system were fully developed, domestic gas production would not be able to keep up with demand, meaning there would still be the need for imports and their corresponding infrastructure, According to IEA estimates, China will shift to a net importer of gas by 2010, when demand will reach 60 bcm.[101] China's strategy regarding natural gas imports involves pipelines from Central Asia and Russia and LNG terminals that import LNG from Australia, Southeast Asia and perhaps the Middle East.

CNPC, Sinopec, and CNOOC are the main players currently active in the development of China's natural gas infrastructure and much of the activity has been focused developing the import capacity needed to meet future demand. CNPC was the major sponsor of China's most important pipeline project to date, the West-East pipeline, while CNOOC has taken the lead in developing LNG import terminals. One characteristic of the LNG terminals has been the concurrent development of gas-fired power plants that can provide steady demand for a portion of the imported LNG while other forms of demand are being established. One gas distribution project of note is in Hangzhou, where Shell and Hong Kong & China Gas (Towngas) are working with Hangzhou Gas, the local distributor, to build over 100 km of pipeline and two city-gate stations.

Major Natural Gas Infrastructure Projects

Sector	Name	Expected completion	Capacity
E&P	Changbei Gas Field	2007	3 bcm/yr
LNG	Guangdong LNG	2006	4 mtpa
LNG/Power/Gas	Putian (Fujian) LNG	2008	2.6 mtpa
LNG/Power	Qingdao (Shandong) LNG/Qingdao Power	2009	4 mtpa

[101] IEA World Energy Outlook, 2005

LNG/Power	Rudong (Jiangsu) LNG/Rudong Power	2010	3 mtpa/ 2,400 MW
LNG/Power	Zhejiang LNG	2010	4 mtpa/ 2,800 MW
LNG	Shanghai LNG	2010	4 mtpa
Gas Pipeline	West-East Pipeline	2005	30 bcm/yr
Gas Pipeline	Kazakhstan-Xinjiang Pipeline		8-10 bcm/yr
Gas Pipeline	Russia-Northwest China Pipeline		20-30 bcm/yr
Gas Pipeline	Russia-Northeast China Pipeline		20-30 bcm/yr

Much of the financing for infrastructure projects is supplied by domestic commercial banks. The government has attempted to provide incentives for foreign investment in infrastructure projects and has been successful to some extent. However, many of the incentives have been granted on a project-by-project basis, reducing transparency within the sector overall and increasing the difficulty of attracting sustained foreign investment.

INDONESIA

Available Energy Resources

	Natural gas	Oil	Coal
Proven Reserves	2.56 tcm	4.7 bn bbls	5.5 bn short tons
Production (2003)	73.6 bcm	1.2 mm bbls/d	132.4 mm short tons

Source: EIA - Country Analysis Brief, Indonesia

Indonesia has proven oil reserves of 4.7 billion barrels, a decrease of 13% since 1994.[102] However, there are a multitude of unexplored basins in eastern Indonesia that might have additional reserves.

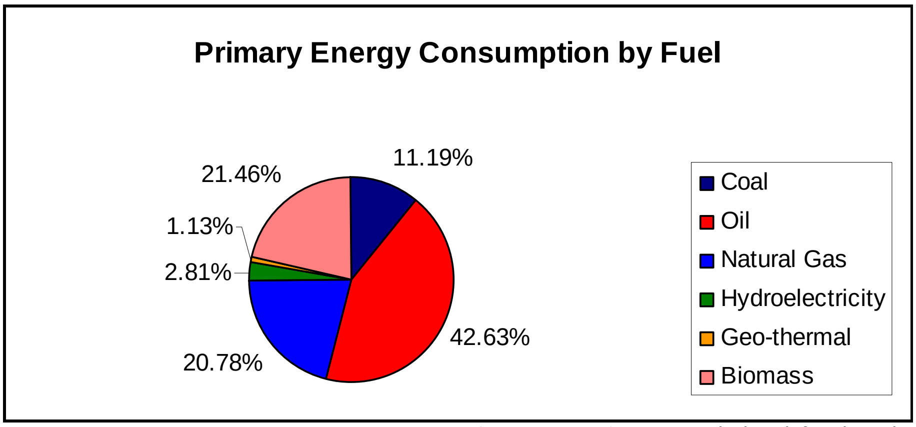
With a capacity to supply 26% of the world's LNG needs, Indonesia is the largest exporter of LNG in the world. In terms of LNG market share, Indonesia has 22.9% of the world market share and 33% of the Asia-Pacific market. Because of declining oil production, Indonesia's government has begun using its natural gas resources for domestic power generation. Indonesian gas, however, is currently up against stiff competition from other suppliers, such as Australia, Brunei Darussalam, Malaysia, and Qatar. In addition, most of the economy's long-term LNG contracts with Japan, Korea, and Chinese Taipei are expiring in the near term and there is a high probability that the agreements will be scaled down or not renewed at all.

[102] EIA, "Indonesia", Country Analysis Briefs, October 2005.

Indonesia plans to double its current coal production of 132 million short tons over the next five years with a majority the new capacity coming from private mines. The additional capacity will be exported to its East Asian neighbors and India.

Indonesia, according to the EIA, has an installed electrical generating capacity of 21.4 GW with 87% coming from thermal sources, 10.5% from hydropower, and 2.5% from geothermal. Capacity is insufficient to meet current demand. After the Asian financial crisis and the opening of Indonesia's power market to independent power producers (IPPs), Indonesia has faced ongoing electricity supply shortages.

Current Energy Mix



Source: EIA - Country Analysis Brief, Indonesia

Oil is the main contributor to Indonesia's fuel mix due to strong growth in the transportation sector.[103] Indonesia's oil production, however, has been declining while demand has increased. Biomass is also a significant component of the energy mix, as Indonesia is an archipelago complicating the delivery of modern fuels.

Coal demand is forecasted to increase as coal will become more prevalent in power generation. In 2002, coal constituted about 41% of power generation in Indonesia, while oil, gas, hydro and other renewables made up 21%, 17%, 3%, and 17%, respectively.

Indonesia, the single Southeast Asian OPEC member, has become a net oil importer as of 2004. Analysts predict that oil production in Indonesia will continue to decline relative to increases in consumption. Greenfield projects, such as Pertamina and ExxonMobil's development of the Cepu block, which will begin production in 2009 and have a peak output of 180,000 bbl/d, will be insufficient to supplant the declining production of mature fields.

[103] Energy and Mineral Resource for the Republic of Indonesia, data for 2003

Energy Strategy

According to the Indonesian Ministry of Energy and Mineral Resources, if no further action is taken by the government, the economy's crude oil reserves will be depleted within the next 18 years, coal reserves within 157 years, and gas reserves within 62 years.

The Indonesian government, therefore, has initiated legislative reform to attract investment into its energy sector. Law 22/2001 was introduced in 2001, calling for the deregulation of the upstream and downstream sectors. This effectively eliminated Pertamina's 25-year monopoly as of November 2005. Additional legal changes in 2005 have enabled international private oil and gas companies to extend contracts beyond the previous 20-year limit. These changes have made possible the development of the Cepu fields, as well as BP's development of three natural gas production blocks for the Tangguh project.

The government has also attempted to damper domestic demand by eliminating consumption subsidies for domestic retail fuel consumers. The retail price of gasoline and diesel, as a result, has increased more than twofold.

Energy Infrastructure

Indonesia has limited infrastructure and is particularly lacking in its gas transmission network. As a result of rising demand for natural gas, and in an attempt to boost gas production and reduce oil consumption, the Indonesian government issued interim permits to nine companies allowing them to distribute natural gas to industrial consumers.

Upcoming infrastructure development projects include BP's Tangguh project in Papua province. Two trains will be constructed with a combined capacity of 340 billion Bcf/y, with expansion capability to 680 Bcf/y. Tangguh has more than 14 Tcf of natural gas reserves.

In addition, state-owned electricity company PLN has entered into an agreement with Pertamina to construct an LNG regas terminal in Cilegon in West Java. The project will help reduce dependence on coal for power generation. Pertamina has also announced plans to build an LNG liquefaction terminal, to be completed by 2010, in Donggi in Sulawesi.

MALAYSIA

Available Energy Resources

	Natural gas	**Oil**	**Coal**
Proven Reserves	2.12 tcm	3.0 bn bbls	-
Production (2004)	48.1 bcm	855,000 bbls/d	-

Source: EIA - Country Analysis Brief, Malaysia

Malaysia's oil reserves have declined significantly from 4.3 billion barrels in 1997 to around 3 billion barrels in 2004. New offshore discoveries, especially deepwater oil reserves, have increased the economy's overall oil production; but at current rates of production, Malaysia's oil reserves are expected to last only another 12 years.

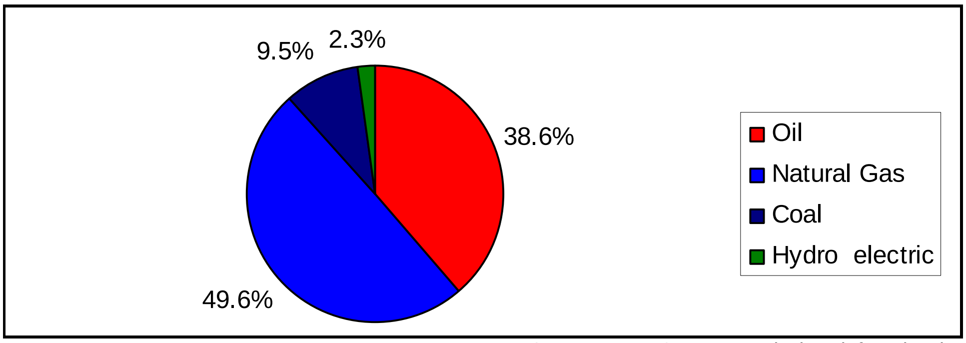
Malaysia holds 2.12 trillion cubic meters of proven natural gas reserves. Natural gas production has been increasing in recent years, reaching 48.1 billion cubic meters in 2004. If the level of production remains unchanged, gas reserves are expected to last only 34 years. JDA, the Malaysia-Thailand Joint Development Area, is considered the most active gas development area for the economy. Malaysia has the world's largest liquefaction center in a single location, Bintulu LNG, with a total capacity of 23 million mt a year.

Malaysia generated around 67 billion kilowatt hours of electricity in 2002. Malaysia's electric generation capacity is approximately 14 GW, of which 12 GW are thermal and 2 GW are hydroelectric. The Malaysian government is enhancing the use of coal for electric power generation to reduce the economy's reliance on natural gas. An investment of US$9.7 billion is forecasted by the government in the electric utility sector through 2010.

Current Energy Mix

Oil and gas currently dominate Malaysia's energy mix, and this situation will be further solidified by the recent discovery of new oil and gas fields in deepwater and ultra-deepwater exploration areas. However, the government is trying to introduce energy-efficiency measures to reduce this trend, given the sparse reserves.

Primary Energy Consumption by Fuel



Source: EIA - Country Analysis Brief, Malaysia

Domestic consumption of gas has been expanding rapidly in recent years, the major market being power generation, which made up 72% of total consumption in 2003. The other principal outlet for natural gas is as a feedstock/fuel for industrial users, which accounts for 16% of domestic demand.

Petroleum will continue to be used as feedstock in petrochemical, polymer, and other downstream industries. With the continuous increase in oil prices and the oil shortage faced by the world, as indicated by members of OPEC, Malaysia's strategy is to invest in more development and research to explore more fields as only half of the identified exploration area so far has been explored. New discoveries will result in more reserves, thus increasing the overall capacity of the economy's oil and gas industry. Data from the Malaysian Ministry of International Trade and Industry (MITI) show an increase in oil and gas exports. Crude oil exports increased by 51% to reach RM2.45 billion (US$0.66 billion) in March 2005, LNG exports increased by 34.5% to RM1.95 billion (US$0.53 billion) refined oil product exports rose by 31.6% to reach RM1.47 billion (US$0.40 billion).

Energy Strategy

In an effort to reduce the dependence of the power sector on oil and gas, especially given increasing oil prices, the government introduced the Eighth Malaysia Plan (2001-2005) which presents coal as a major alternative for oil and gas. All exploration projects are to be done in partnership with the national oil company, Petronas. In an effort to ensure a continuous and cost-effective oil and gas supply in the future, the government has approved power generation schemes that support its policy regarding the development of gas fields. Developments in the oil and gas sector will be further enhanced to strengthen Malaysia's share in the domestic and overseas markets. Malaysia's strategy is to invest in more development and research to explore more fields, as only half of the identified exploration area so far has been explored. Malaysia announced on June 14, 2004, during the Asian Annual Oil and Gas Conference in Kuala Lumpur that its goal is to increase oil and gas production by 3% per year for the next five years.

Energy Infrastructure

Investments in Malaysia's infrastructure by private and public sectors started to recover slowly after the 1997-1998 financial crisis. The Eighth Malaysian Plan (2001-2005) allocated a total of US$1.62 billion to be invested in the petroleum industry, with 67.5% (US$10.9 billion) to be spent on development and production activities by Petronas and its contractors. The most important initiative under the ASEAN Energy Cooperation to date is the Trans-ASEAN Energy Network comprising both the Trans-ASEAN Gas Pipeline (TAGP) and ASEAN Power Grid.[104] In late 2002, Indonesia began to deliver gas from West Natuna to Malaysian Petronas' offshore Duyong facilities. ASEAN's first cross-border pipeline currently delivers 150 million scf/d of gas from Malaysia to Singapore. On the horizon are projects to deliver gas to Malaysia and to Thailand from the Malaysia -Thailand Joint Development Area.[105]

[104] http://www.petronas.com

[105] http://www.usembassyjakarta.org/econ/aseanpipe1.html

MEXICO

Available Energy Resources

	Natural gas	Oil	Coal
Proven Reserves	420 bcm	14.8 bn bbls	1.1 bn short tons
Production (2004)	37.1 bcm	3.8 ml. bbls/d	8.2 mm short tons

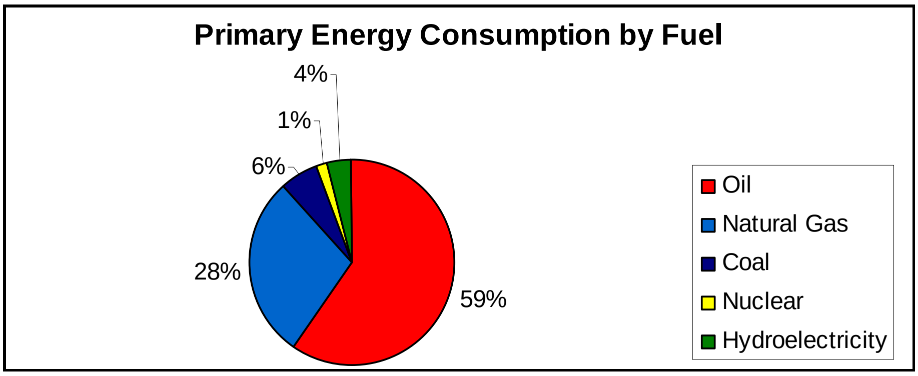
Source: BP Statistical Review of World Energy June 2005

According to BP's Annual Statistical Review, Mexico's proven reserves stood at 14.8 billion barrels at the end of 2004, making them the fourth largest proven oil reserves in the Americas behind Venezuela, the United States, and Canada. Mexico's production capacity stood at around 3.82 million bbl/d, making the economy the fifth largest oil producer in the world. More than 60% of this production comes from Cantarell oil field, located in the Gulf of Campeche, which is one of the largest oil fields in the world.

Mexico has the sixth largest gas reserves in the Americas, behind the United States, Venezuela, Canada, Argentina, and Bolivia. Of Mexico's gas reserves, 59% are located in the north of the economy. Proven reserves have declined from 1994's year-end amount of 1.94 tcm[106] to the current volume shown in the table above. Mexico's natural gas production outputs have increased from 32.4 bcm in 1994 to 47.8 bcm in 2004.[107]

As of 2005, the economy's recoverable coal reserves stood 1.1 billion short tons. Mexican coal is characterized as having very high ash content, and its production cost is higher than that of imported coal.

Energy Mix



Source: BP Statistical Review of World Energy June 2005

[106] BP Statistical Review of World Energy June 2005, p. 20

[107] SENER – Natural Gas Market Outlook 2005-2014, p 92

Consumption of natural gas has increased from 33.3 bcm in 1994 to 59.1 bcm in 2004[108], with the largest increase in consumption experienced in the power sector, with demand reaching 58.2 Mcm/d in 2004. According to estimates from SENER, 95% of the population has access to electricity. Mexico's electricity consumption in 2002 was 167.3 billion kWh.[109]

It is projected that by 2012, 45% of the economy's natural gas demand will come from the power sector, and that natural gas-fired plants will account for 60% of Mexico's power capacity. Correspondingly, power output derived from oil is predicted to decline to 24.2%.

Mexico's demand for natural gas has been estimated to increase to 81.6 bcm (SENER) by 2010. Mexico is expected to remain a short-term net importer of U.S. natural gas to supply industry located on the U.S.–Mexican border. This is expected to change as LNG regasification terminals in Mexico come on line to supply both the U.S. and the Mexican markets.[110]

Energy Strategy

The two main goals of the Mexican government are to increase domestic production of oil and gas, and to develop LNG regasification import terminals. Unfortunately, energy reform has come to a standstill, hindering advancement towards more cost-effective and efficient infrastructure for the sector. In addition to advancements in oil and gas production, developing reliable and affordable electricity generation is a top priority for the government.

In 2000, under President Vicente Fox, Pemex introduced a Strategic Gas Plan that called for an increase in domestic natural gas production to 82.7 bcm by 2008.[111] The plan outlined the following goals: 1) increase natural gas production through multiple service contracts; 2) diversify foreign natural gas sources by importing more LNG to decrease dependence on domestic and U.S. production; 3) flare less associated gas (it is estimated that Pemex flared 7.5 Mcm/day in 2002[112]); 4) increase natural gas transport, distribution, and storage capacity, specifically increasing interconnection capacity between the Mexican and U.S. pipeline grids; and 5) increase proven reserves by allotting more money to exploration. Five years into this program, natural gas production has increased at a rate of 6% a year to reach 135.5 Mcm/d by the end of 2005; two LNG terminals are under construction, with others being developed (as highlighted below) with one of them starting operations by the end of the year; gas flaring has been

[108] *Ibid*, P 59

[109] IEA Energy Statistics – Mexico; Electricity

[110] Resources Law International - Great Expectations: Cross-Border Natural Gas Trade In APEC Economies, P. 101

[111] EIA – Country Analysis Brief, Mexico

[112] EIA – Country Analysis Brief, Mexico

reduced from 5.5% total production in 2002, to 3.7% of total production at the end of the third quarter of 2005[113].

The Mexican constitution prohibits private investment in its oil and gas sectors. Multiple Service Contracts (MSCs) were created to allow private investment in the gas industry while complying with the constitutional ban on concessions. MSCs work as follows: private companies finance 100% of the contract, they are paid for services rendered, and the natural gas produced remains the property of Pemex. MSCs, however, have failed to attract major oil and gas companies, so much so that earlier last year Pemex suspended bidding rounds for additional contracts.

Energy Infrastructure

Pemex operates 5,700 miles of natural gas pipelines in Mexico. The company has eleven natural gas processing centers, which produced 450,000 bbl/d of natural gas liquids (NGLs, including condensates) and 760,000 tons of sulfur in 2004. Pemex also operates most of the economy's natural gas distribution network, which supplies processed natural gas to consumption centers.[114] Mexico currently has ten natural gas connections with the United States.

As Mexico embarks in a plan to introduce LNG, two regasification facilities are under construction and four others are under development, with another one going out to tender in the near future.

PROJECT	SPONSOR	LOCATION	CAPACITY	STATUS
LNG REGAS TERMINAL Altamira	Shell Total Mitsui	East Coast	0.5 MmCF/D ramping up to 1.3 BCF	In Construction – Operations: End of 2006
LNG REGAS TERMINAL Costa Azul	Sempra Energy/ Shell	West Coast	1 BCF/day	In Construction-2008 Operations
LNG REGAS TERMINAL Terranova	Tidelands	East Coast-Offshore		Early Development
LNG REGAS TERMINAL Coroado Islans	Chevron	West Coast-Offshore	1.4 BCF/day	Late Development
LNG REGAS TERMINAL Lazaro Cardenas	Resol-YPF	West Coast	0.39 BCF/day ramping up to 1.3 BCF	Early Development
LNG REGAS TERMINAL Sonora	DKRW	West Coast	1.3 BCF/day	Early Development
LNG REGAS Manzanillo	[IN TENDER]	West Coast	0.5 BCF/day	Construction to start later 2006

113 PEMEX – Financial Results Report Sep 30th, 2005

114 EIA – Country Analysis Brief, Mexico

In addition to the LNG regasification efforts, additional gas infrastructure projects underway include TransCanada's Tamazunchale Pipeline. TransCanada was awarded a contract by Mexico's Comisión Federal de Electricidad (CFE) to build, own, and operate a natural gas pipeline in east-central Mexico. The 36-inch, 80-mile pipeline will extend from the facilities of Pemex Gas near Naranjos, Veracruz and transport natural gas to an electricity generation station near Tamazunchale, San Luis Potosi. The pipeline will be designed to transport initial volumes of 170 Mmcf/d. Under the contract, the pipeline's capacity will be expanded to approximately 430 Mmcf/d to meet the needs of two additional proposed power plants near Tamazunchale.[115]

PAPUA NEW GUINEA

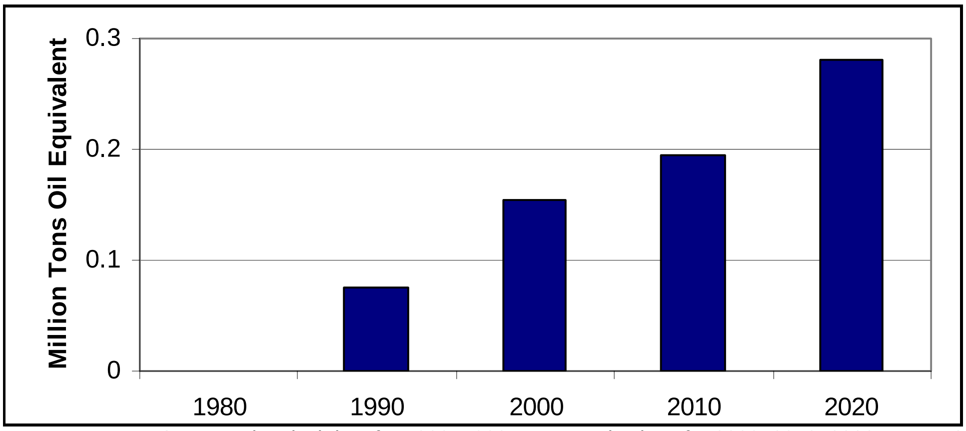
Available Energy Resources

Oil production is estimated at 46,200 bbl/day and consumption is estimated at 15,000 bbl/day. The economy has proven reserves of 170 million bbls of oil. Natural gas production and consumption are both estimated to be 110 million cubic meters annually. Reserves are estimated at 385.5 bcm. Papua New Guinea has no coal or other energy resources.

Current Energy Mix

Natural gas use for electricity generation is projected to increase from 200,000 tons oil equivalent in 2000 to 300,000 tons oil equivalent in 2020. Power generation makes up nearly 100% of gas demand, and will continue to do so through 2020.

Evolution of Natural Gas Use in Papua New Guinea, 1990-2020[116]



Source: Historical data for 1980, 1990 – IEA; Projections for 2000, 2010, 2020 - APERC

[115] http://www.transcanada.com

[116] Natural Gas Market Reform in the APEC Region – 2003 (APERC), p. 114, Figure 55

Papua New Guinea is currently self sufficient in its energy consumption and could be a natural gas exporter with the right amount of investment in exploration and development. There is little trade in oil, either imports or exports.

Energy Strategy

Papua New Guinea's tax structure has been criticized for making investment in mining too expensive and leading mineral exploration companies to look for cheaper exploration targets, such as Asia, Latin America, and the countries of the former Soviet Union. To revive waning mineral and petroleum exploration interest, the Government announced a major overhaul of the tax system aimed at encouraging the development of the US$3 billion natural gas pipeline underway between Papua New Guinea and Australia, and furthering mineral exploration. The new tax regime became applicable only when a project was underway and included guaranteed fiscal stability for the financing period of a project, the lowering of corporate tax rates to 30%, and the reduction of the dividend holding tax to 10%. Companies also were able to deduct 25% of exploration expenditure against total income. Companies will be required, however, to pay an additional profit tax when accumulated profits exceed a 15% rate of return.

Energy Infrastructure

Oil Search Limited owns the Hides Gasfield and sells its natural gas to the Porgera joint venture for electricity generation at the Porgera gold mine. Exxon has spearheaded the development of a natural gas pipeline that would run from the Papua New Guinea highlands to the central eastern coast of Queensland, Australia. The project was to include 635 km of pipeline within Papua New Guinea (320 km onshore, 315 km offshore) and 2,615 km within Australia (2,455 km onshore, 160 km offshore). When completed, the pipeline would transport natural gas from Papua New Guinean gas fields into Northern Queensland via the Torres Strait, down the Cape York Peninsula to the port city of Townsville, down to the industrial city of Gladstone, and on to the Queensland State capital city of Brisbane for an estimated cost of US$2.5 billion. The Project includes gas wells and associated infrastructure at the Gobe, the Hides, and the Kutubu oil and gas fields; a wet gas pipeline that would follow the route of the existing oil pipeline from the oil and gas fields to a processing facility off the coast in the Gulf of Papua that will separate the wet gas into its component product streams; and a dry gas pipeline that links with the Queensland markets.

Papua New Guinea is also exploring options for building an LNG liquefaction facility to export its gas.

PERU

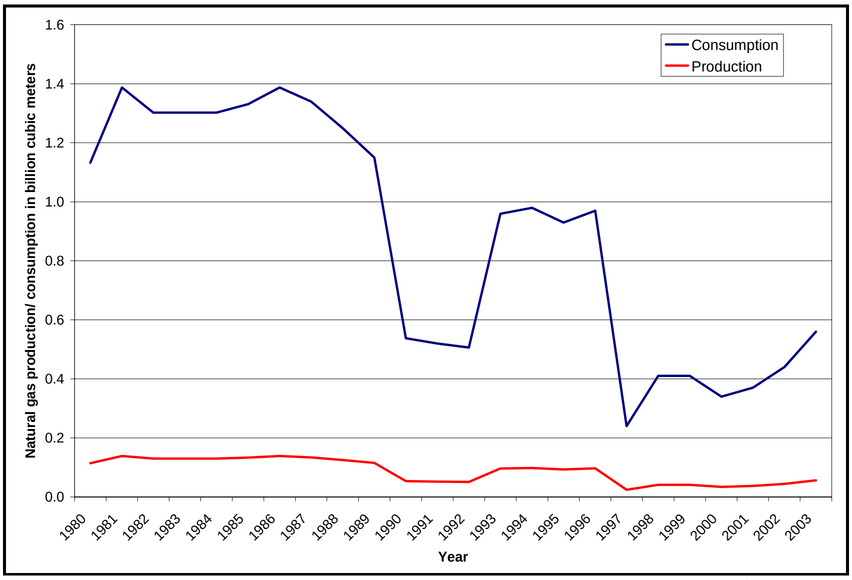
Available Energy Resources

	Natural gas	Oil	Coal (2003)
Proven Reserves	246 bcm	930 mm bbls	1.17 bn short tons
Production	0.56 bcm	112,000 bbls/d	20,000 short tons

Source: EIA - Country Analysis Brief, Peru

Oil production in Peru has declined steadily over the past two decades as its oil fields have matured. Peru's crude oil reserves are concentrated in the north of the economy and mostly consist of heavy crude. Oil is produced from both onshore and offshore fields. New potential reserves were discovered in 2004, both in the Amazon region and offshore. The fields are currently being explored.

Natural Gas Consumption and Production

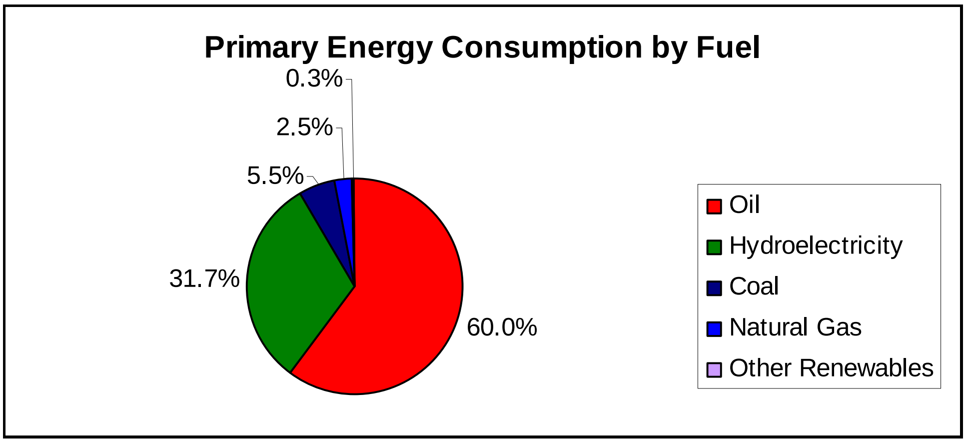


Source: EIA

Peru's proven natural gas reserves, according to *Oil & Gas Journal*, amount to 246 billion cubic meters. Most of these reserves are located in the recently discovered Camisea gas fields. It is expected that the Camisea project will produce far more than the projected domestic demand, and Peru is thus expected to become a natural gas exporter.

According to the USDOE/EIA, Peru's recoverable coal reserves amount to 1.17 billion short tons. Domestic production does not meet the demand, however, and Peru is a net coal importer. Peru's location in the Amazon basin also gives the economy abundant water resources that may be used to produce electricity.

Current Energy Mix



Source: EIA - Country Analysis Brief, Peru

According to the EIA, 88% of Peru's electricity supply is generated from hydroelectric facilities. Conventional thermal power plants are used during peak periods, or in the case of a water shortage that hampers hydroelectric production.

With the development of the Camisea project, more of Peru's electricity will be sourced from new gas-fired power plants (the projects will be discussed in more detail below). Hydroelectricity will, however, remain the main source of power generation.

Energy Strategy

Peru's policy regarding the development of its hydrocarbon resources was established in a 1993 Act. The objective of the government was to promote private sector investment in oil and gas and limit government intervention in the sector. With the development of its own natural resources, particularly the Camisea gas fields, Peru hopes to reduce its dependency on foreign energy, and to become a net exporter of natural gas. The Camisea project is also expected to lower electricity prices, as domestic natural gas will be cheaper than imported oil, coal or gas.

Regional energy policies also are playing an important part in Peru's energy strategy. In July 2005, Peru formed a working group with Argentina, Chile, Uruguay, and Brazil to study the future of Peru's gas exports. The Peruvian government has sought to attract private and foreign investment since the 1990s and Peru's constitution guarantees national treatment to foreign investors. Although the energy sector is more restricted than other sectors of the economy; foreign companies can obtain concessions and rights within the restricted areas by government approval, as was the case with the Camisea project. Perupetro, a government agency established in 1993, is in charge of subscribing contracts for the exploration and/or exploitation of hydrocarbons and promoting investments in the oil and gas sector.

Energy Infrastructure

Camisea is the heart of natural gas developments in Peru. The field itself began production in August 2004, and the gas is transported by pipeline to Lima and Callao for household and industrial consumption. The total project cost, according to the InterAmerican Development Bank, is US$1.651 billion, divided into US$730 million for the upstream part (development of the gas fields themselves), US$850 for the downstream part (pipeline) and US$71 million for the gas distribution network in Lima and Callao. See Chapter 8 of this report for more detailed information on the Camisea project.

As a complement to the Camisea project, Hunt Oil, SK Corporation, and Repsol YPF are currently developing the Peru LNG project. The objective is to build an LNG liquefaction facility to export natural gas to Mexico and the west coast of the United States. The facility will have an initial output of over four mtpa. The total cost of the project is estimated at US$1.1 billion. The project sponsors launched a tender for the engineering, procurement, and construction (EPC) contract in October 2005. Completion is scheduled for 2009.

Other potential projects around the Camisea gas fields include a pipeline to Chile. Peru's investment promotion authority, Proinversión, is currently studying this idea. Previous plans of building a gas pipeline between Camisea and Bolivia have been halted due to the highly instable political situation in Bolivia.

Several power projects using gas from Camisea are also under development. BPZ Energy plans to build a 140MW plant in Caleta Cruz, and Etevensa began construction in 2004 of a gas-fired power plant at its existing Ventanilla plant. Although the government is encouraging the development of gas-fired power plants, hydroelectricity continues to prove popular and two new hydro projects have recently received funding from the World Bank.

PHILIPPINES

Available Energy Resources

	Natural gas	Oil	Coal
Proven Reserves	107.6 bcm	200 mm bbls	260.1 mm short tons
Production (2005)	2.8 bcm	25,600 bbls/d	2.2 mm short tons

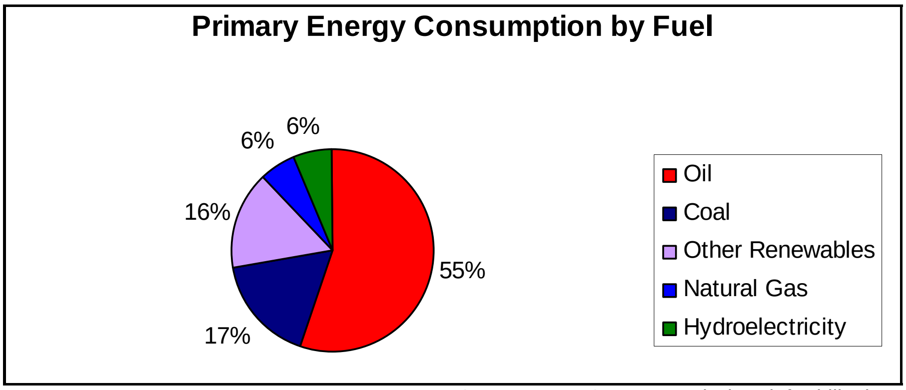
Source: EIA - Country Analysis Brief, Philippines

Despite the fact that the Philippines has 107 bcm of proven natural gas reserves, before the commercialization of the Malampaya gas plant in 2001 there was no significant gas production.[117] Currently, Malampaya provides gas to three power plants, totaling 2,700 MW in capacity, namely the 1,200MW Ilijan, the 1,000MW Sta.Rita and the 500MW San Lorenzo plant in Batangas. These three gas-

[117] *Ibid.* p.3

fired power plants, together with a small 3MW one in Isabela, generate a total of 12,386 GWh of electric power, accounting for 19% of the total power generated within the Philippines.[118]

Current Energy Mix



Source: EIA - Country Analysis Brief, Philippines

The residential sector is predicted to capture increasing amounts of energy, as rural electrification becomes more widespread and as the standard of living increases throughout the next decade.[119]

The Philippines will continue to depend on oil and gas imports for meeting the economy's energy demands throughout the next ten years.[120] However, it is important to note the ever decreasing reliance on oil as a source of fuel, despite the constantly increasing need for energy within the Philippines. This is primarily because of the substantial investments in gas and renewable energy.

Energy Strategy

The government's first goal has been to decrease the dependency on oil and to increase the security of energy supply through further investing in the gas and renewable sectors. Another major goal has been to assure that the electricity shortages of the 1990s are not repeated, and to bring the electricity debt under control. A parameter that will to a large extent determine the success of the latter goal is the completion of the privatization program in the energy and electricity sectors. However, the National Power Company (Napocor) had not succeeded in selling a single asset by the end of 2004. During 2005, the government privatization body, the Power Sector Assets and Liabilities Management Corporation (PSALM) announced the plan to sell nine more Napocor power plants before December. PSALM has been successful in selling six Napocor plants by the end of 2005.

[118] APEC Energy Site, Statements on Notable Energy Developments since EWG28 (November 2004)

[119] *Ibid* slide 13

[120] *Ibid* slide 9 and slide 11

To achieve both diversification of supply and decreased dependency on oil, the government has taken and continues to develop several measures. One such measure includes the possibility of investing in regasification terminals to import LNG from Australia, Brunei Darussalam, Indonesia, Malaysia, or Qatar. This investment, if finally undertaken, will be complemented by two pipelines, one 100 km from Batangas to Manila and one 150 km from Bataan to Manila.[121] In addition, the Government is considering an additional 1,200 MW of geothermal capacity, which would make the Philippines the largest producer of geothermal power in the world.[122]

The Philippine Energy Plan 2005 Update states that the Department of Energy has set a goal of 60% self sufficiency by 2010. They will achieve this by: increasing indigenous oil and gas reserves; aggressively developing renewable energy sources; increasing the use of alternative fuels; forging strong strategic alliances with other economies; and promoting a strong energy efficiency and conservation program. The Philippines also has a goal of complete rural electrification by 2008. The DOE committed to electrify 1,476 barangays (i.e., village) by the end 2005. The use of natural gas will be intensified in the transportation sector as well, with the currently implemented Natural Gas Vehicle Program for Public Transport.

THE RUSSIAN FEDERATION

Available Energy Resources

	Natural gas	Oil	Coal
Proven Reserves	48.0 tcm	72.3 bn bbls	142.9 bn short tons
Production (2005)	589.1 bcm	9.3 mm bbls/d	254.8 mm short tons

Source: BP Statistical Review of World Energy June 2005

Russia is home to the world's seventh largest oil reserves, which, at the end of 2004, BP estimates at 72.3 billion barrels of proven reserves.[123] According to the IEA, these reserves can sustain production at current levels for 22 years.[124] Ultimately recoverable resources, however, are much more substantial.

Russia also possesses the world's largest gas reserves, holding around 48 tcm. Independent gas producers control licenses to fields holding 28% of these reserves, which amount to more than 13 tcm.

[121] Asian Development Bank, Technical Assistance to the Republic of the Philippines for Institutional Strengthening for the Development of the Natural Gas Industry October 2003. p.1-2

[122] EIA, Ibid p.6

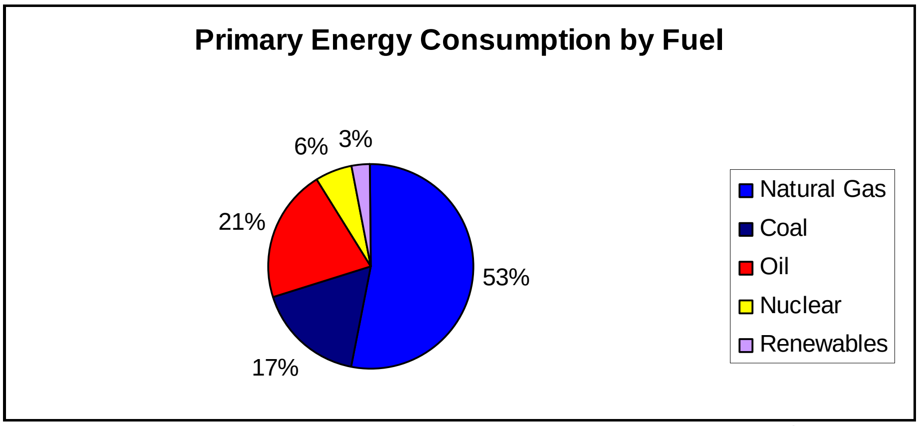
[123] *BP World Energy Review*, 2005.

[124] IEA, "Russia – An In-Depth Study", *World Energy Outlook 2004*.

Gazprom, Russia's state-run natural gas monopoly, controls licenses to 55%, while the remaining 17% are unallocated.[125]

Russia holds the world's second largest recoverable coal reserves, behind the United States, with 143 billion short tons.[126] With rising demand for coal, largely emanating from Asia, Russia's coal production could increase substantially. Environmental concerns and Russia's signing of the Kyoto Protocol, however, might hinder growth in this sector.

Current Energy Mix



Source: EIA

Russia's fuel mix is dominated by natural gas. Demand for gas has increased from 47% in 1992 to 53% in 2002.[127] Concurrently, oil demand has fallen from 28% to 21% over the same period, as a result of a reduction in the quantity of oil used in power generation. In 2002, coal, nuclear, and renewables made up 17%, 6%, and 3%, respectively, of primary energy demand.[128]

The IEA forecasts that demand for oil will increase at 1.6% per year as a result of continued development in the transport sector. Natural gas is projected to rise by 1.5% per year due to increased gas usage in the power generation sector. Coal demand is estimated to decline slightly, while nuclear power will grow at minimal rate over the next decade before falling gradually.[129]

[125] IEA, "Russia – An In-Depth Study", *World Energy Outlook 2004*.

[126] *BP World Energy Review*, 2005.

[127] IEA, "Russia – An In-Depth Study", *World Energy Outlook 2004*.

[128] *Ibid.*

[129] *Ibid.*

The IEA predicts that Russia will remain the world's largest gas exporter throughout its projection period to 2030. Net exports will continue to rise with increased imports from Central Asia to enable higher exports to Europe.[130]

Coal exports are projected to remain flat because of infrastructure constraints and strong worldwide competition. If the government supports coal use in the power sector, however, demand and production will increase.[131]

Energy Strategy

The Russian government stated in its Energy Strategy 2020 that aims to:

- Restructure natural monopolies in the gas, electricity, and coal industries.
- Mobilize investments in production and export capacity.
- Decrease energy intensity of production and supply.
- Decrease production costs and liquidate loss-making enterprises.

To boost natural gas and oil production, the Russian government has initiated a gradual increase of domestic gas prices as an incentive to producers. In addition, independent gas producers now have increased access to the state-owned pipeline system. More favorable tax policies are in place to stimulate the development of small and medium fields, rehabilitation of more mature fields, and the development of more technically complex gas reserves.

Incentives to invest in Russia's energy sector include the economy's abundant energy assets, extensive infrastructure, and strong export and domestic markets. Moreover, Russia is well-positioned to increase exports to Europe and Asia. Despite the aforementioned, investors in the Russian energy sector are faced with insecure property rights, heightened risks of terrorist attacks, and the current strengthening of the Kremlin's control of the economy. Potential investors in the gas sector, for example, are particularly vulnerable as Gazprom, in addition to its commercial functions, has been granted regulatory functions. Thus, the state-controlled firm has command of the pipeline infrastructure, monopolizes all gas exports outside of the New Independent States (NIS) markets, and stakes claim to the most attractive fields.

Energy Infrastructure

The gas transmission network faces bottleneck issues. Gazprom-owned United Gas Transmission System (UGTS) controls the world's largest natural gas pipelines in the world -- 222,000 kilometers in total. The infrastructure is aged, however, and, if Gazprom is to increase its European sales, new export routes and replacement and/or refurbishment of the pipeline network will be needed.

[130] *Ibid*.

[131] *Ibid*.

Recent, Ongoing and Future Projects

Two major gas pipelines are currently being considered: the Yamal-Europe II and the North European Gas Pipeline. Yamal-Europe II would expand the Yamal-Europe I pipeline, which transports gas from Russia to Poland and Germany via Belarus. . Poland and Gazprom have yet to agree on the exact route. The Russian government issued a decree in early 2004 supporting the construction of the North European Gas Pipeline, which would transfer gas from Russia to Finland and the United Kingdom via the Baltic Sea. Approximately 700 miles of the pipeline would pass under the Baltic Sea. The expected cost of the project is US$5.7 billion.[132]

The upstream gas industry is also in need of major investment. Russia's Ministry of Economic Development estimates that US$160 billion is required between 2005 and 2015. To reach new export markets, namely North America, South-East Asia, and Great Britain, Gazprom is considering LNG export facilities at Murmansk, Yamal, and Shtokman. While Gazprom currently has no LNG volume, by the end of the decade, the natural gas monopoly will have more than 50 mtpa in Atlantic Basin projects.

In the meantime, the Sakhalin-II developers have already begun construction of Russia's first LNG plant on the southern tip of the island. The Sakhalin Group consisting of Shell, which holds a 55% interest and operatorship, Mitsui with 25%, and Mitsubishi with 20%, has sold over 70% of its projected output of 9.6 million tons per under long-term offtake agreements with Japanese and Korean firms. Because of the considerable Japanese interest in the success of this project, JBIC will be the biggest lender to the planned 16-year US$6 billion project financing.[133]

THAILAND

Available Energy Resources

	Natural gas	Oil	Coal
Proven Reserves	376 bcm	583 million bbls	1.5 bn short tons
Production	22.6 bcm	259,000 bbls/d	20.7 mm short tons

Source: EIA - Country Analysis Brief, Thailand

Thailand contains about 376 bcm of proven natural gas reserves. In 2002, it 22.6 bcm. Domestic consumption in 2002, including imports from Burma, was 904 Bcf. Much of the economy's natural gas is used for generating electricity. In 2001, Thailand completed its program for the conversion of almost all oil-fired electric power plants to natural gas. Demand for natural gas is expected to rise at a 5%-6% annual rate over the next five years, which represents a substantial revision downward from previous

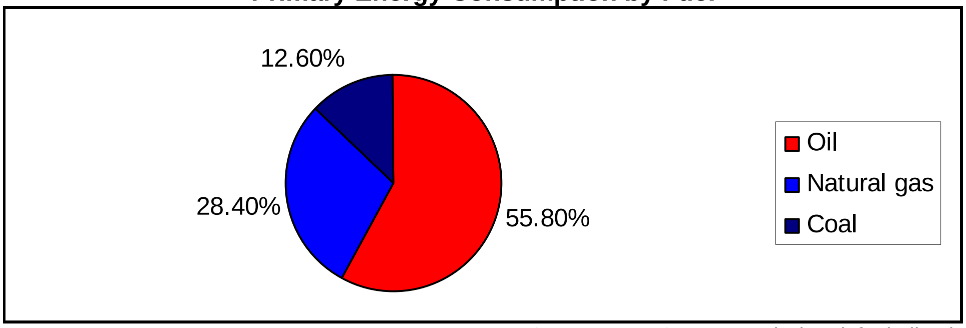
[132] EIA, "Russia", Country Analysis Briefs, February, 2005.

[133] "Sak 2 endgame afoot", *Project Finance International*, January 11, 2006.

official estimates. Bongkot is Thailand's largest gas field, located 400 miles south of Bangkok in the Gulf of Thailand.

Current Energy Mix

Primary Energy Consumption by Fuel



Source: EIA - Country Analysis Brief, Thailand

Thailand's current energy regulation includes energy conservation schemes that have led to a continuous increase in domestic energy production and a reduction in the economy's reliance on imports, particularly oil. Thailand now produces around 20% of its required petroleum, but in 1992 the economy imported 90% of its energy needs, mostly oil. By 2001, this figure fell to just over 60% and as has continued to decrease.

Energy Strategy

The Thai Government's energy policy is aimed at conserving and developing domestic energy resources, as well as promoting the efficient use of energy while protecting the environment. In particular, Thailand hopes to reduce its dependency on energy sources from foreign countries.

Thailand's Energy Strategy includes the following policies:

- Promoting the combined use of energy by further developing the use and exploitation of Thailand's natural gas as the economy's major source of energy.
- Promoting the development and use of alternative and renewable energy sources.
- Emphasizing energy management and conservation to increase the competitiveness of Thailand's industries and stabilize energy prices through appropriate monetary, fiscal, and managerial measures.

In May 2005, the Thai government announced a US$20 billion spending package for the economy's energy sector. The plan aimed at optimizing the use of hydrocarbon fuels, improving energy efficiency, and increasing the use of renewables. The plan includes US$3.2 billion for new gas pipelines and expansion of refineries, US$8 billion to build new petrochemical plants, and US$351 million to enlarge oil tank farms.

Energy Infrastructure

A 416-mile Thai-Burmese natural gas pipeline, running from Burma's Yadana gas field in the Andaman Sea to an Electricity Generating Authority of Thailand's (EGAT's) power plant in Ratchaburi province, was completed in mid-1999 at a cost of US$1 billion. A new connecting line also has been built linking Ratchaburi to the Bangkok area.

PTT, formerly known as the Petroleum Authority of Thailand, is the national oil company and continues to dominate the oil sector in Thailand. PTT is currently undergoing a restructuring process. Major foreign oil companies operating in Thailand include Chevron, Shell, Total, and Unocal. The major refineries and their respective crude oil refining capacity in bbl/d include the Shell Company of Thailand (275,000), Thai Oil Co. Ltd (192,850), Esso Standard Thailand Ltd. (173,500), and PTT (61,750).

There is the possibility of the development of a pipeline for the supply of natural gas from the Tay Nam field in Gulf of Thailand into Viet Nam's main industrial center, Ho Chi Minh City. The PPT has also investigated the possibility of a possible pipeline interconnection from Thailand with Burma and India.

VIET NAM

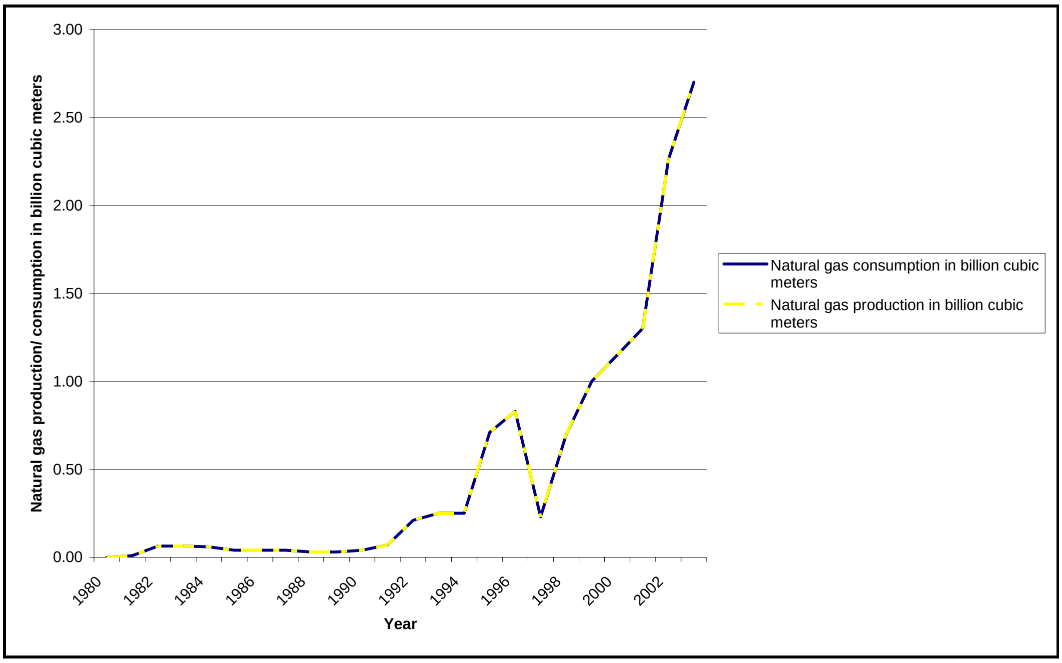
Available Energy Resources

	Natural gas	Oil	Coal
Proven Reserves	192 bcm	600 mm bbls	165 mm short tons
Production (2004)	2.8 bcm	366,400 bbls/d	17.6 mm short tons

Source: EIA - Country Analysis Brief, Viet Nam

Viet Nam's proven oil reserves amount to 600 million barrels, but this figure continues to increase as exploration continues. New discoveries are made regularly and the government continues to grant new exploration licenses to foreign oil companies. Viet Nam's oil reserves are almost entirely located offshore. Viet Nam exports crude oil, but due to its lack of refining capacity, the economy actually imports refined petroleum products. This situation is likely to change with the construction of the economy's first refinery in 2006.

Natural Gas Production and Consumption in Viet Nam 1980-2003



Source: EIA

Viet Nam's natural gas reserves officially amount to 192 billion cubic meters, but estimates go as high as 280 billion cubic meters[134]. Currently all the natural gas produced in Viet Nam is used for domestic consumption.

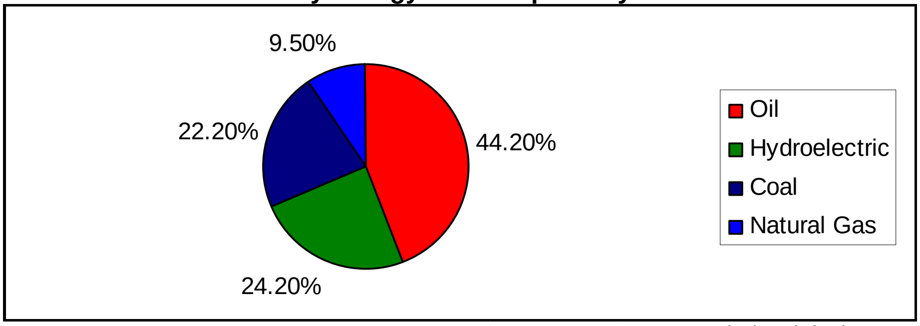
The largest gas producing area in Viet Nam is the Cuu Long basin, a major source of associated gas from oil production. Two natural gas fields are also exploited in the Nam Con Son and the Northern Red River basins. The gas is primarily used to power the Phu My complex, which was discussed in Chapter 8 of this report.

Viet Nam has large coal reserves, which are principally anthracite, estimated at 165 million short tons according to the EIA. Viet Nam is a net exporter of coal mostly to Japan and China. Viet Nam also has abundant water resources that are used to produce hydroelectricity.

[134] EIA

Current Energy Mix

Primary Energy Consumption by Fuel



Source: EIA - Country Analysis Brief, Viet Nam

The graph above presents the total energy consumption of Viet Nam, both for industrial and power generation purposes. The energy mix for power consumption is slightly different. Sixty percent of Viet Nam's power is generated by hydroelectric facilities.[135] To obtain a more balanced energy mix, the government has encouraged the construction of coal-fired power plants, and more recently of gas fired power plants. Viet Nam's total power generation capacity is 8.3 GW[136] and is not sufficient to meet demand. In addition, the general Vietnamese population does not have much access to energy sources and relies on non-commercial biomass energy sources, such as wood and rice husks, for its energy needs.

Energy Strategy

Viet Nam uses long-term economic planning for the exploitation of its natural resources. The Vietnamese government is developing the economy's energy producing capacity to keep pace with the economy's growth and to increase exports. To do so, Viet Nam wants to develop its domestic energy resources to achieve energy independency. The government also has plans to develop the economy's refining capacity and petrochemical industry. The increased use of natural gas could be extended to energy consuming industries, such as cement, metallurgy, and construction materials. Finally, Viet Nam is considering the potential benefits of using natural gas to power vehicles.

PetroVietNam, Viet Nam's state-owned oil company, has come up with a Gas Utilization Master Plan (GUMP) to make the most efficient use possible of the economy's natural gas reserves. The first step of the implementation of GUMP in the 1990s was the use of associated gas from the White Tiger oil fields for power generation and in an LPG plant. For the 2003-2010 period, PetroVietNam is studying the possibility of building a gas pipeline between Phu My and Ho Chi Minh City, as well as developing several small pipelines in the south of the economy to better link gas production centers and populated areas.

[135] EIA

[136] EIA

However, the main projected use of natural gas is power generation, and this will be undertaken in cooperation with Electricity of Viet Nam (EVN).

In the southwest of the economy, PetroVietNam has recommended making the Cuu Long Delta a major power and fertilizer center, increasing total capacity from 1,200 - 1,300 MW in 2005 to 3,000 - 3,500 MW around 2010. A 400 km pipeline to bring gas to the new Ca Mau power and fertilizer complex is also under consideration.[137]

In addition to developing the use of natural gas, the Vietnamese government is encouraging the diversification of energy sources. EVN is investing a total of US$2.8 billion in 16 new power generation facilities, which include gas-fired, coal-fired and hydroelectric power plants. The government also wants to increase the share of renewable energy to 10% of the total electricity generation. According to the Ministry of Industry, nuclear energy is also being considered.[138] A subsidiary of PetroVietNam signed a contract in 2005 with Keeper Resources to study the coal-bed methane potential of the Red River coal basin.

Energy Infrastructure

Viet Nam's natural gas infrastructure is concentrated around three production basins: Northern Red River, Nam Con Son, and Cuu Long Basin. Gas from the Cuu Long Basin is used by Viet Nam's only Liquefied Petroleum Gas (LPG) plant, located in Dinh Co. The LPG plant produces 700-800 tonnes of LPG and 350 tonnes of condensate per day; the production currently exceeds domestic demand and the surplus is exported, mostly to Japan.[139] Gas from Cuu Long is also used to fire the Ba Ria power plant.

BP and ConocoPhillips are developing the Nam Con Son offshore gas field together with PetroVietnam. Total cost for the development of the project is estimated at US$1.3 billion. The project is expected to supply more than 3 billion cubic meters per year over 20 years. Most of the Nam Con Son gas is currently consumed by the Phu My power and fertilizer complex. Phu My has four power plants with 3,600 MW of total generation capacity, and a 740,000-tpa urea plant.

The Cuu Long Basin in the southwest of the economy is currently the least exploited source of gas. A major power and fertilizer complex is planned in Ca Mau, based on the model of the Phu My complex. A 720 MW gas-fired power plant is currently under construction in Ca Mau; an 800,000 tpa urea plant is

[137] Petrovietnam, Gas Utilization Master Plan, 2003

[138] Viet Nam Ministry of Energy,http:// www.moi.gov.vn

[139] Petrovietnam

also planned.[140] Gas will be brought from the offshore field via a 325 km pipeline, expected to be operational in late 2006.[141]

[140] Petrovietnam

[141] Infrastructure Journal, October 18, 2005

Appendix C

Chapter 4 Supporting Data

MIT's Cost of Electricity Assumptions

	Coal	Gas - Low	Gas - High	Nuclear
Capital Costs	$1,300/kW	$500/kW	$500/kW	$2,000/kW
O&M/Fuel Cost	$1.20/mmbtu	$3.50/mmbtu	$4.50/mmbtu	1.5 cents/kWh
O&M/Fuel Cost Escalation	0.5% per year	0.5% per year	2.5% per year	1.0% per year
Heat Rate	9,300 btu/kWh	7,200 btu/kW	7,200 btu/kW	
Construction Period	4 years	2 years	2 years	5 years
Capacity Factor	85%	85%	85%	85%
Percent Debt financing	60%	60%	60%	50%
Interest Rate on Debt	8%	8%	8%	8%
Return on Equity	12%	12%	12%	15%
Project Life	25 years	25 years	25 years	25 years

ExternE's External Costs for Electricity Production in the European Union (Euro cents/kWh)

Country	Coal & Lignite	Gas	Nuclear	Wind
AUT		1-3		
BE	4-15	1-2	0.5	
DE	3-6	1-2	0.2	0.05
DK	4-7	2-3		0.1
ES	5-8	1-2		0.2
FI	2-4			
FR	7-10	2-4	0.3	
GR	5-8	1		0.25
IE	6-8			
IT		2-3		
NL	3-4	1-2	0.7	
NO		1-2		0-.25
PT	4-7	1-2		
SE	2-4			
UK	4-7	1-2	0.25	0.15