ASIA PACIFIC ENERGY RESEARCH CENTRE

NATURAL GAS PIPELINE DEVELOPMENT

IN NORTHEAST ASIA

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FOREWORD

I am pleased to present the report, 'The Costs and Benefits of Large Scale Natural Gas Resource Development, Phase I: Natural Gas Pipeline Development in Northeast Asia.' After completing the APEC Energy Demand and Supply Outlook in March 1998 and the September 1998 Update to the Outlook, APERC focused on the six research themes designated by the APEC Energy Working Group, including this natural gas infrastructure study.

This study investigates the economic feasibility of large-scale natural gas pipeline projects in Northeast Asia. In this report, trends in gas supply and demand are analysed, and the potential for importing natural gas via pipeline into China, Japan, and Korea is assessed. Economics of pipeline natural gas projects is illustrated with simple project evaluation models, followed by discussions of key issues regarding the regional pipeline projects currently in the making. The cost of transporting gas under several scenarios is analysed and compared with LNG, which is attached in the Appendix. Several conclusions and implications are then drawn. It is our hope that this study can advance and provide direction to the discussion and future analyses related to pipeline development in East Asia.

Please note that this work is published by APERC as an independent analysis and does not necessarily reflect the views or policies of the APEC Energy Working Group.

Finally, I would like to thank all those who have been involved in this work, including the staff at the Centre, Mr Jeong-Kyu Seo at Korea Energy Economics Institute, Jensen Associates, Sarkeys Energy Center, the experts who attended the natural gas conference, and many others who have provided helpful comments and insights.

Keiichi Yokobori
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APERC would like to acknowledge and thank James Jensen of Jensen Associates, Inc. for his extremely valuable assistance and insights into determining the methodology used in the case study and in setting up the scenarios. He also performed the comparative economic analysis presented in the Appendices.

APERC also received valuable information and guidance concerning natural gas production and reserve estimates in Asia, Russia, and Central Asia from Dennis O'Brien, Boyko Nitzov and others at the Sarkeys Energy Center.

APERC would also like to thank Mr Jeong-Kyu Seo of Korea Energy Economics Institute, for his valuable assistance and extensive comments in economic analysis.

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EXECUTIVE SUMMARY

The objective of this study is to analyse the economic feasibility of large-scale natural gas pipeline projects in Northeast Asia, focusing in particular on economic and environmental issues. Also a case study scenario has been developed, analysing the relative costs of transporting gas from regional supply sources to markets in China, Japan, and Korea by both pipeline and LNG.

The Russian Far East and the East Siberian regions have enough natural gas supply potential to meet future demand growth. Nevertheless, the pipeline gas from those regions has to compete with domestic natural gas in China, and LNG from various sources.

There is enough potential demand to justify a natural gas pipeline project in the region, with China, Korea, and Japan being possible markets. The main drivers for natural gas infrastructure growth are environmental protection, energy security, and gas technology development.

The feasibility of natural gas projects is, in general, distance-dependent. Distance is the key variable determining whether trade in gas will be via pipelines or as LNG. There are a number of other factors affecting the economics of natural gas pipeline projects, including debt ratio, interest rates, transport volumes, tax rates, and end uses. Currently there are many uncertainties, including the effects of the 1997 financial crisis, the likely impacts of energy market deregulation, and political and economic stability in Russia.

There are some country-specific issues waiting to be resolved for pipeline projects to materialise: the natural gas market is not mature in China as there is little infrastructure developed and prices of alternative energy are relatively low. In Korea, even though a nation-wide trunk line is nearing completion, a lack of commitment by KEPCO may restrict the market potential of pipeline gas from Russia.

Counter-balancing these potential barriers, electricity and natural gas sector deregulation once in full swing (combined with environmental regulations) in Northeast Asia, could substantially increase demand for natural gas to fuel power plants.

Of all pipeline projects considered, the Irkutsk project is most attractive due to relatively short distances, and hence potentially viable construction costs, from the gas fields to markets in China and Korea. The Yakutsk project on the other hand, despite abundant proven reserves, would face substantial difficulties due to the need to build long pipelines over permafrost, adding to construction costs. The smaller-scale Sakalin project is underway, and could provide additional gas supplies to Japan because of its geographical proximity.

Once implemented, these pipeline projects would offer a wide range of benefits: macroeconomic benefits from increased economic activity; enhancement of energy security through regional cooperation; opportunities for resource development; foreign capital flows into the Russian region; and improvement of environmental quality. In addition, regional development could be facilitated along the pipeline route.

In order to advance a natural gas pipeline project in this region, appropriate institutional structures (financial and legal) would need to be put in place, and transparent policies developed to attract domestic and foreign capital.

Growing environmental awareness at both national and global levels is likely to benefit these projects. Local acid rain in the Northeast Asian economies and global warming in the world are attracting increasing attention. Demand for cleaner air and stable world climate have been rising as living standards improve. Encouragement for the expansion of natural gas infrastructure could come about as a result of the Climate Change Convention, as governments attempt to place an economic value on carbon emissions.

Unlike the rest of the world, North East Asian economies have not accumulated experience in trans-boundary, natural gas pipeline projects. Although these economies anticipate mutual economic benefits, they tend to be hesitant in taking the initiative. The lack of experience may be a stumbling block.

Therefore regional cooperation among concerned economies could be critical to the success of these projects.

The following conclusions are from the case studies included in the Appendix.

- The estimated transportation cost of LNG into the Changjiang Delta (Shanghai) region is likely to be lower than the pipeline transportation cost from major remote supply sources.
- The economic gain from the introduction of pipeline gas from Sakhalin to Japan is significantly lowered when the construction cost of linking internal distribution networks is included.
- Transportation costs are largely affected by distance, which in turn determines the type of trade (i.e. LNG or pipeline natural gas). The maximum distance for pipeline transportation is roughly 8,500 km, based on current natural gas trade statistics. In this respect, the proposed Irkutsk and Sakhalin pipeline projects appear to be good candidates.

CHAPTER 1

INTRODUCTION

Since the introduction of natural gas to Japan in 1969, gas consumption has grown rapidly, both in Japan and Korea, and recently in China and Chinese Taipei. Demand is projected to continue to increase despite the current financial difficulties in the region. Compared to other regions of the world Northeast Asia under-utilizes natural gas, a fuel that is increasingly becoming the fuel of choice for many uses.

Large-scale hydrocarbon resources are present in Northeast Asia, namely in the Russian Far East and east Siberia. Growing expectations of large-scale natural gas production potential in East Siberia and the Russian Far East has stimulated much discussion and many proposals for pipeline development in this region. Except for some small-scale Sakhalin projects, no project has been implemented, primarily for economic reasons.

Unlike oil, natural gas projects require long-term and relatively large financial commitments, entailing exposure to risks involving markets, taxes and tariffs, and cost overruns. These risks are substantial, and some argue that regional pipeline projects will not eventuate anytime soon as LNG is currently available.

The objective of this study is to address issues relevant to the feasibility of natural gas pipelines from areas in East Siberia, the Russian Far East, Central Asia, and Southeast Asia to markets in China, Korea, and Japan.

The rationale behind this study involves:

- APEC Non-Binding Energy Policy Principles

> Article 1: *Emphasize the need to ensure energy issues are addressed in a manner which gives full consideration to harmonisation of economic development, security and environmental factors.*
>
> Article 2: *Pursue policies for enhancing the efficient production, distribution and consumption of energy.*

- APEC Ministers Declaration of Okinawa Meeting held in 1998

> Paragraph 17: *Driven by the goals of promoting economic development and growth, increasing energy security and improving the environment, demand for natural gas in APEC is expected to grow significantly over the next 20 years. Meeting this demand will require increased natural gas production and significant new infrastructure development.*
>
> Paragraph 18: *Natural gas trading networks comprised of internal and cross-border pipelines, LNG terminals and distribution systems would promote economic development within economies and further cooperation and trade between the APEC economies. Feasibility studies on pipeline projects in this region should be conducted.*

This report proceeds as follows. In Chapter 2 the regional demand for natural gas will be discussed, followed by an analysis of the supply potential of Australia, China, Southeast Asia and Russia in Chapter 3. The economics of gas pipeline projects is to be investigated, with particular focus on transportation and the netback value of natural gas in Chapter 4. Chapter 5 reviews some of the issues that could affect the feasibility of pipeline natural gas projects. Chapter 6 will present the conclusions of the study.

CHAPTER 2

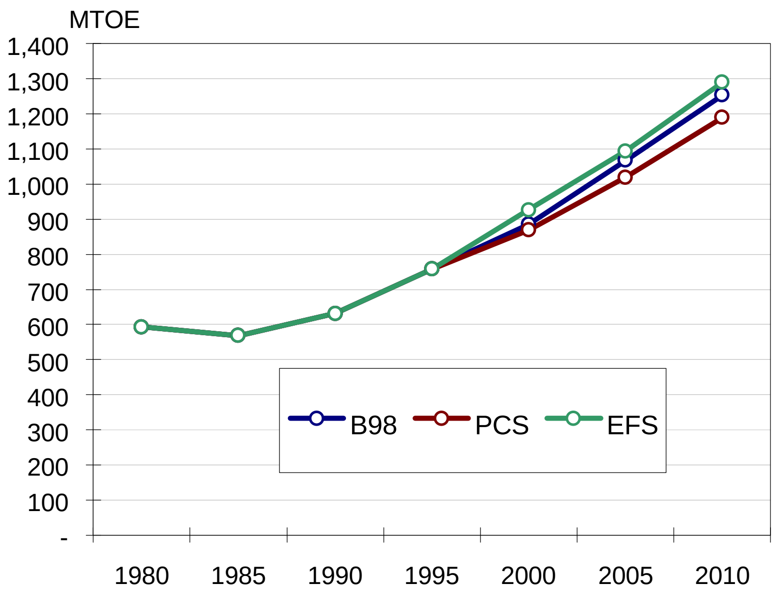
NATURAL GAS DEMAND IN NORTHEAST ASIA

TRENDS IN NATURAL GAS CONSUMPTION

This section will review natural gas consumption trends in Northeast Asia. The *APEC Energy Demand and Supply Outlook*, updated by APERC in September 1998, will be the basis for the analysis but other information and forecasts will also be referenced. In this study, Northeast Asia consists of China; Japan; and Korea.

Natural gas consumption in Asia is expected to continue to rise at a rapid pace despite the current economic downturn across the region (Figure 1). Economic growth is the primary driver of natural gas demand and, while growth has slowed considerably from past trends, recovery is expected to occur around 2000 or shortly thereafter (APERC, 1998c). But even with economic recovery, projections of energy demand are lower than those of even the recent past, resulting in reassessments of many gas-related projects in the region. The three projections are from the APERC Outlook updated in September 1998.

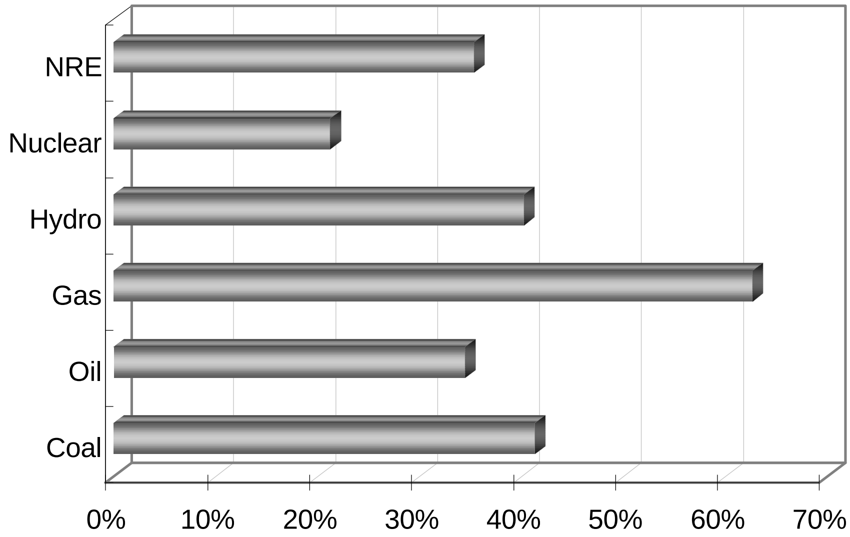
Figure 1 Natural gas consumption in the APEC region



Source: APERC, (1998c)

While APERC's projections for natural gas have been reduced in the updated Outlook, reductions in natural gas demand estimates are not as severe as for other energy sources. In addition to economic growth, natural gas consumption is driven by concerns for energy security and the environment as well as technology. Concern for energy security and the environment led Japan to initiate the expansion of LNG trade in the 1970's. As the region's dependence on outside sources of oil continues to grow, economies are looking to gas as one means of reducing oil consumption. Environmental considerations in general, but particularly the Kyoto protocol of December 1997, are pushing economies to consider natural gas, which produces the lowest emissions of greenhouse gases and other pollutants of all available fossil fuels. Natural gas demand has also been stimulated by technological improvements, especially in the power generation sector, with combined cycle turbines increasing the efficiency of combustion, and hence competitiveness of natural gas. For these reasons, natural gas growth rates are projected to outpace those of other fuels.

Figure 2 Percentage change in TPE by energy source in APEC region (1995-2010 - B98)



Source: APERC, (1998c)

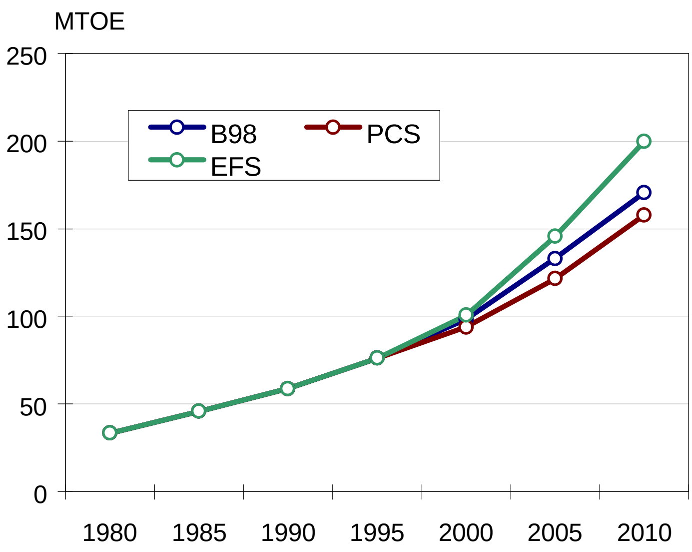
NORTHEAST ASIA

Northeast Asia consists of economies that, by and large, produce little or no natural gas and are large-scale importers. China is an exception, being a significant gas producer. However, depending on the extent of gas expansion, China could also become a large gas importer in the future.

Primary energy consumption of natural gas in Northeast Asia is projected to show a 2.2 fold increase, or 5.5 percent *per annum* (pa), from 76.22 Mtoe in 1995 to 170.6 Mtoe in 2010 (B98 in Figure 3). This compares to a 2.3-fold increase (5.7 percent pa) from 1980 to 1995. In absolute terms, the natural gas increase is lower than that of coal or oil, but on a percentage basis, natural gas is by far the fastest growing fuel. APERC projects that under a scenario in which recovery from the current financial crisis occurs more slowly (the protracted crisis scenario or PCS), natural gas will grow 2.1 times (5.0 percent pa) from 1995 to 2010. Under an environmentally friendly scenario (EFS), natural gas is expected to grow even more rapidly, 2.6 times (6.6 percent pa) over the 15-year forecast horizon.

Natural gas is under-utilized in Northeast Asia compared to other regions of the world. Despite the expected rapid growth of natural gas in Northeast Asia, natural gas' share of total energy consumption still lags that of other economies (Figure 4). On a world-wide basis, according to BP Statistics, gas made up 23 percent of total primary energy consumption in 1998. The APEC region is composed of several groups of economies. In the Northeast Asian economies, natural gas is not used as widely as in the west, as shown in the diagram. The share of natural gas in total primary energy is a mere 5 percent while for European countries and the United States, the shares are 22 percent and 24 percent respectively.

Figure 3 Natural gas consumption in North East Asia



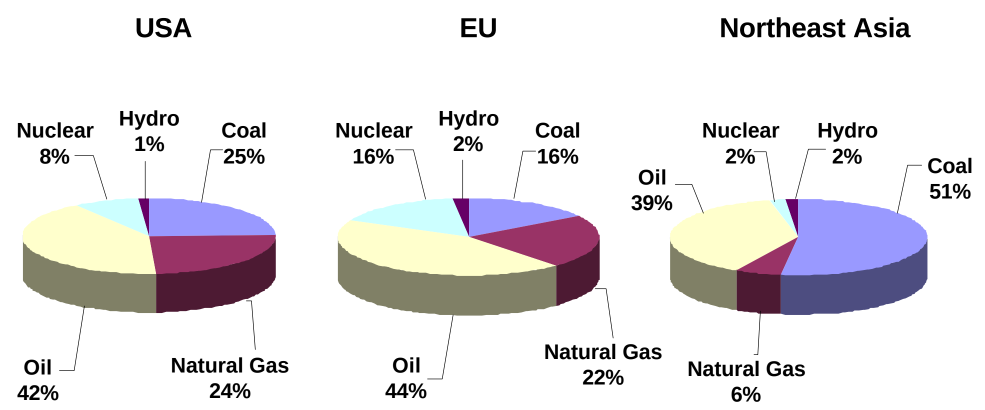
Source: APERC, (1998c)

One of the major reasons for lower gas utilisation in Northeast Asia is the difficulty of bringing gas into these economies. LNG requires large scale processing facilities and significant gas consumption to be feasible. An 'anchor,' a large consumer in one location, has often been needed to make a project economic. Seen in Figure 6, this has usually been a power generator. When Japan and Korea began importing LNG, power generators were the largest users. Power generation use comprised 70.3 percent of the gas consumed in Japan 1998. This contrasts with the United States where natural gas consumption is more evenly split between the residential/commercial, industrial, and power generation sectors.[1] However, natural gas is utilised somewhat differently within the economies in Northeast Asia, as will be shown in a market assessment of individual economies.

The shares of natural gas have been rising and are expected to rise over the forecast period with Korea reaching nearly the same level as Japan. China is also projected to raise its natural gas share to nearly 4 percent in the baseline scenario. To provide an example of the market potential of natural gas, a specific case can be highlighted. Currently Japan and Korea rely solely on LNG for their natural gas supply. Based on the currently secured LNG contracts and future demand potential from the APERC projection, it is estimated the gap between the contracted supply and projected demand will reach 30.9 million toe (equal to 25 million LNG tonnes), as seen in Figure 7. This amount is more than twice the volume of the current annual consumption of natural gas in Korea.

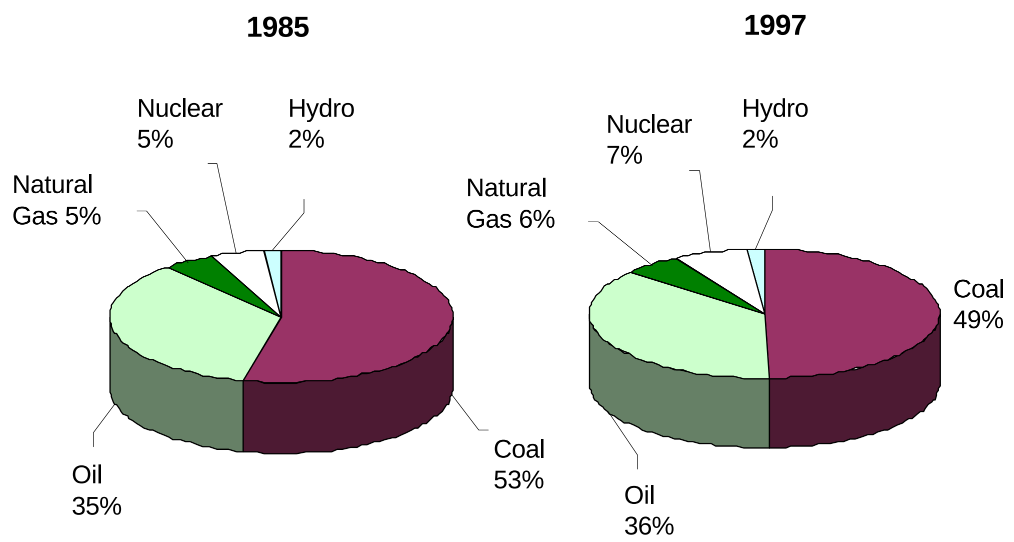
1 Using 1995 data from the APEC database, 37 percent of the natural gas consumed in the United States was in the combined residential and commercial sector, 35 percent in the industrial sector, and 25 percent in the power generation sector, which includes co-generation.

Figure 4 Share of natural gas in terms of total primary energy supply in 1997



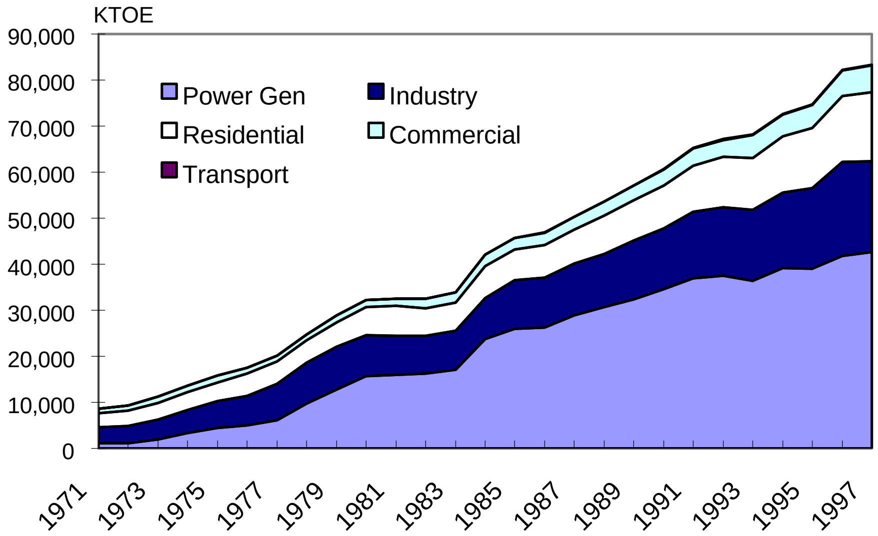
Source: IEA (1998b)

Figure 5 The share of total primary energy supply in 1985 and 1997 in Northeast Asia



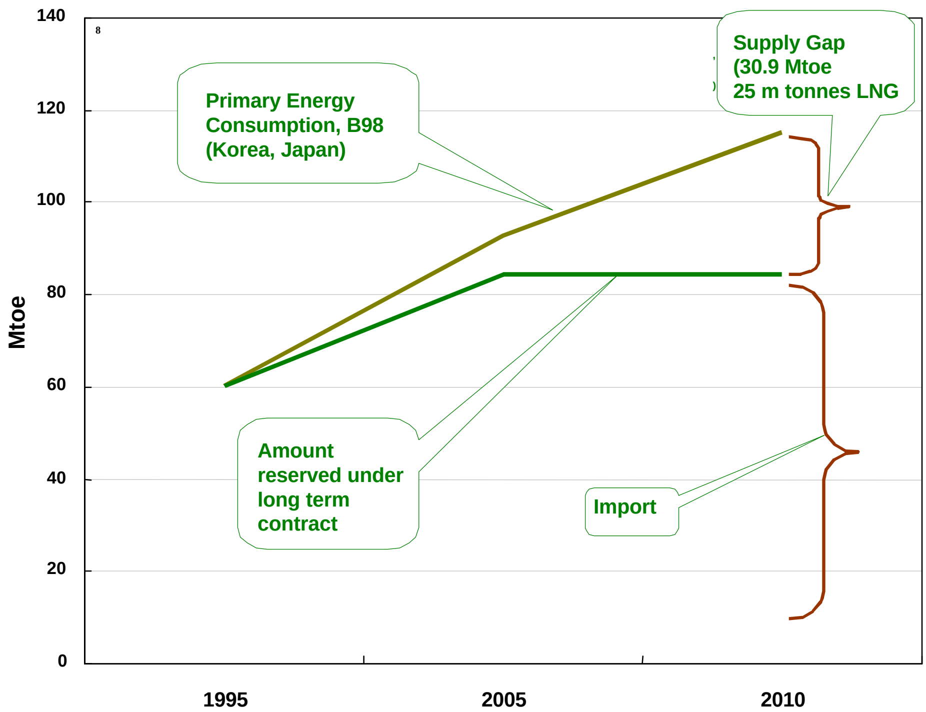
Source: IEA (1999d)

Figure 6 Natural gas consumption trends in Northeast Asia by sector



Source: IEA (1999d)

Figure 7 Natural gas market potential in Japan and Korea



CHINA

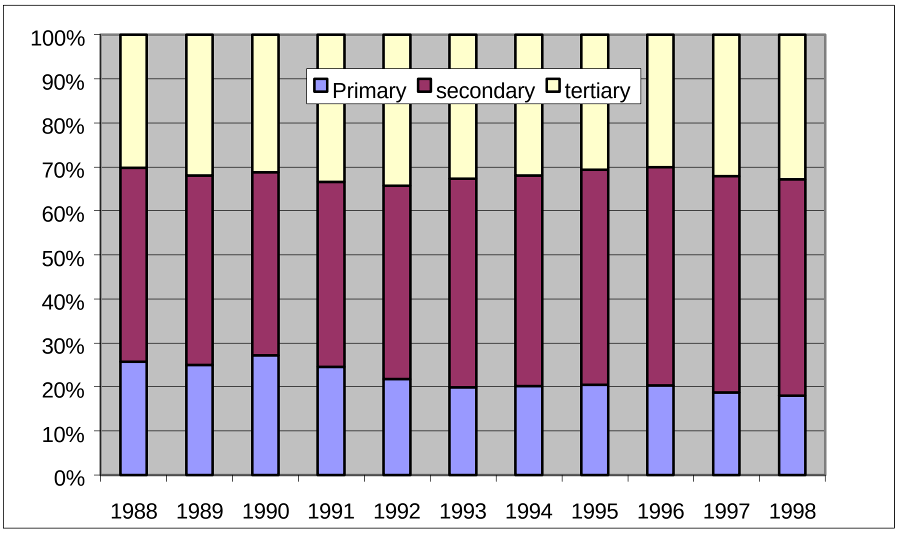
For the last two decades, the Chinese economy has seen marked economic growth, fuelled mainly by coal and oil. The robust growth, even in the midst of the 1997 financial crisis, suggests that China has considerable potential for economic growth over the next few decades. However the increasing energy consumption underpinning the industrial expansion, and rising consumer spending have had substantial negative impacts on the environment, especially air quality in the major cities. In an effort to reduce the environmental degradation arising from high economic growth, the Chinese government has begun to consider energy policies and measures with a greater focus on environmental sustainability.

NATURAL GAS DEMAND IN CHINA

The average growth rate of energy consumption in China was 3.9 percent from 1988 to 1998, while the average GDP growth rate was 9.6 percent. During this period, secondary industries grew strongly, constituting 49.2 percent of total GDP in 1998. Energy consumption has increased in order to meet the growing industrial demand. The only exception to the trend was a temporary decline in energy consumption between 1997 and 1998 despite increasing GDP. There may be a number of explanations for this phenomenon, including the following:

- A structural change in the economy is occurring, with energy intensive industries decreasing in importance, and the low energy intensive tertiary sector increasing in importance with respect to contribution to GDP.
- New technology and environmental policies have improved energy efficiency.
- Partly as a result of the Asian financial crisis, and the transition economy, the GDP growth slowed and therefore some industries suffered from this.
- Some uncertainties existed in statistical surveys, e.g. small consumers.

Figure 8 Sectoral share of GDP in China



Source: A Statistical Survey of China, 1999

Table 1 Primary energy consumption by source in China

	Total Consumption (10000 tce)	Coal	Oil	Natural gas	Electricity
1988	92997	76.2%	17.0%	2.1%	4.7%
1989	96934	76.0%	17.1%	2.0%	4.9%
1990	98703	76.2%	16.6%	2.1%	5.1%
1991	103783	76.1%	17.1%	2.0%	4.8%
1992	109170	75.7%	17.5%	1.9%	4.9%
1993	115993	74.7%	18.2%	1.9%	5.2%
1994	122737	75.0%	17.4%	1.9%	5.7%
1995	131176	74.6%	17.5%	1.8%	6.1%
1996	138948	74.6%	18.0%	1.8%	5.5%
1997	138173	71.5%	20.4%	1.7%	6.2%
1998	136000	71.6%	19.8%	2.1%	6.5%
Ave Growth Rate	3.9%				

Note: Electricity sector includes hydropower and nuclear power.

Source: A Statistical Survey of China, 1999

The major energy source in China is coal, which accounts for more than 70 percent of primary energy consumption. China is sitting on huge coal reserves, accounting for 11.6 percent of total proven global reserves as of the end of 1998 (EDMC, 2000). From a purely economic standpoint, the high coal consumption is an understandable and rational phenomenon.

Oil is the next most important source of energy, comprising between 17 and 20 percent of total primary energy (TPE) consumption, followed by electricity from hydro and nuclear power generation. Natural gas has not been widely used in China, and currently comprises a mere 2 percent of TPE. As Table 2 shows, the share of coal has been gradually declining, while oil and electricity consumption are growing. The share of natural gas has remained relatively static at 2 percent over the last decade, even though absolute consumption has been growing slowly, but steadily at 2.5 percent per annum on average. That is lower than growth in total energy consumption. Lack of natural gas supply infrastructure and high capital investment costs for development are largely responsible for the slow growth of natural gas consumption in China.

Natural gas has been used mainly in the industry sector, which accounted for 82 percent of total natural gas consumption in 1996, the highest growth among all sectors. The manufacturing sub-sector is the main user. The power generation sector uses a relatively small share of natural gas, partly because cheap coal is readily available. The residential sector also accounts for a small share because of the lack of available supply or transmission and distribution networks.

Table 2 Natural gas utilization in China

	Total (BCM)	Industry (BCM)	Residential (BCM)	Generation (BCM)	Other use (BCM)
1991	15.58	12.01	1.81	0.64	1.12
1992	15.63	11.67	2.15	0.65	1.16
1993	16.60	12.52	1.73	0.82	1.53
1994	17.08	13.81	2.00	0.83	0.45
1995	17.35	14.31	1.94	0.79	0.31
1996	17.92	14.66	1.97	0.75	0.55
Average Growth Rate	2.8%	4.1%	1.7%	3.0%	-1.3%

Source: China Energy Statistical Yearbook (1991-1996)

NATURAL GAS SUPPLY

CURRENT ENERGY SUPPLY BY SOURCE

Coal production increased rapidly with the emergence of high economic growth as seen in Table 3, but started declining in 1995. Production of oil has been steady, while electricity production by hydro and nuclear has increased in the last five years. The growth reflects increasing market demand and modified energy policies.

Table 3 Primary energy production by source in China

	Total Production (10,000 TCE)	Coal	Oil	Natural Gas	Electricity
1988	95,801	73.1%	20.4%	2.0%	4.5%
1989	101,639	74.1%	19.3%	2.0%	4.6%
1990	103,922	74.2%	19.0%	2.0%	4.8%
1991	104,844	74.1%	19.2%	2.0%	4.7%
1992	107,256	74.3%	18.9%	2.0%	4.8%
1993	111,059	74.0%	18.7%	2.0%	5.3%
1994	118,729	74.6%	17.6%	1.9%	5.9%
1995	129,034	75.3%	16.6%	1.9%	6.2%
1996	132,616	75.2%	17.0%	2.0%	5.8%
1997	132,410	74.1%	17.3%	2.1%	6.5%
1998	124,000	72%	18.5%	2.4%	7.1%

Source: A Statistical Survey of China, (1999) In 1993, rising oil demand turned China into a net oil importing economy. As a consequence, the government imposed restrictions on the use of fuel oil for power generation. Domestic oil production has not been sufficient to meet the rapidly growing demand from transportation, manufacturing and chemical industries after 1992 (see Table 4).

Table 4 Oil imports and exports in China

	Imports (1,000 tonnes)	Exports (1,000 tonnes)	Net Imports (1,000 tonnes)
1991	12,495	29,307	-16,812
1992	21,247	28,596	-7,349
1993	36,157	25,065	11,092
1994	29,033	23,802	5,231
1995	36,762	24,545	12,217
1996	45,369	26,960	18,409

Source: Energy Report of China, (1997)

NATURAL GAS SUPPLY

Natural gas production has been increasing at an annual average growth rate of 4.6 percent during the period 1991-1996. As more gas fields are developed, production is likely to increase at a higher pace in the future than in the past. China has been known to have huge natural gas resources in Xinjiang, Qhinhai, Shann-Gan-Ning, Sichuan-Chonqing and also some offshore fields.

Table 5 Natural gas supply in China

	Natural Gas (100 million cm)
1991	160.7
1992	157.9
1993	167.7
1994	175.6
1995	179.5
1996	201.1
Average Annual Growth Rate	4.6%

Source: China energy statistical yearbook, (1991-1996)

Four major state-owned corporations share the total natural gas output as seen in Table 6. CNOOC specializing in offshore fields produced 17 percent of the total natural gas output in 1998, while CNPC contributed 83 percent to total output, mostly from onshore fields.

Table 6 Natural gas production in China by corporation

	1997 (mmcf/day)	1998 (mmcf/day)
CNPC	1423.8	1449.7
Sinopec	229.1	224.9
CNOOC	387.0	373.9
CNSPC	87.1	97.7
Total	2136.0	2146.1

Source: Wu, (1999)

PROJECTED NATURAL GAS SUPPLY

China has huge potential natural gas resources according to a nationwide survey by CNPC and CNOOC. The aggregate natural gas resources are estimated at 38 trillion cubic metres, spread over several regions. One issue regarding future natural gas production is that a large portion of the gas resources are not classified as proven reserves[2] so it is not easy to predict the future production plateau level. Wu (1999) argued that China's estimates of proven natural gas reserves were more than twice the international estimates. Nevertheless, more investment in exploration would increase the size of proven reserves of natural gas. The comparison between Table 7 and Table 8 clearly indicates that reserve estimates are low.

Table 7 Regional distribution of natural gas resources in China

Region	Total Resources (tcm)	Share
Xinjing	10.0	26.3%
Qinghai	1.1	2.8%
Shaan-Gan-Ning	4.2	10.9%
Sichuan-Chongqing	7.4	19.4%
East China	3.0	7.9%
Other Onshore	4.3	11.4%
Offshore	8.1	21.4%
Total	38.1	100

Source: CNPC and CNOOC, Wu, (1999)

[2] See CEDIGAZ (1999) for definition.

Table 8 Regional distribution of proven natural gas resources in China

Region	Total Resources (tcm)	Percent
Xinjing	0.4	14.8
Qinghai	0.1	2.3
Shaan-gan-ning	0.3	11.2
Sichuan-chongqing	0.5	18.6
East China	0.9	29.5
Other onshore	0.0	1.1
Offshore	0.7	22.5
Total	2.9	100

Source: CNPC and CNOOC, Wu, (1999)

At a Sino-IEA conference held in Beijing in November 1999, China's state petroleum agencies and companies revealed that China was targeting 70 BCM of domestic production of natural gas per year with the import of 30 BCM per year and the construction of a national transmission network by 2010. In 1998, the combined total of natural gas imports to Japan and Korea was 80.8 BCM. In order to produce 70 BCM and import 30 BCM, China will certainly need huge investment in both upstream and downstream infrastructure.

There are various projections of future production levels of natural gas in China. For example, Miao, (1999) estimated that natural gas production would reach 45.0 BCM in 2005, 64.4 BCM in 2010, and 104.2 BCM per year by 2020 (Miao, 1999). Most projections are within the range provided in Table 9.

Table 9 Natural gas supply forecast for China

	2000 (BCM)	2010 (BCM)	2020 (BCM)
Domestic Production	25	50-100	60-130
Import Pipeline	0	10-20	20-40
LNG	0	5-10	5-15
Total	25	65-130	85-185

Sources: EIA, Royal Institute of International Affairs, BIA, Battelle

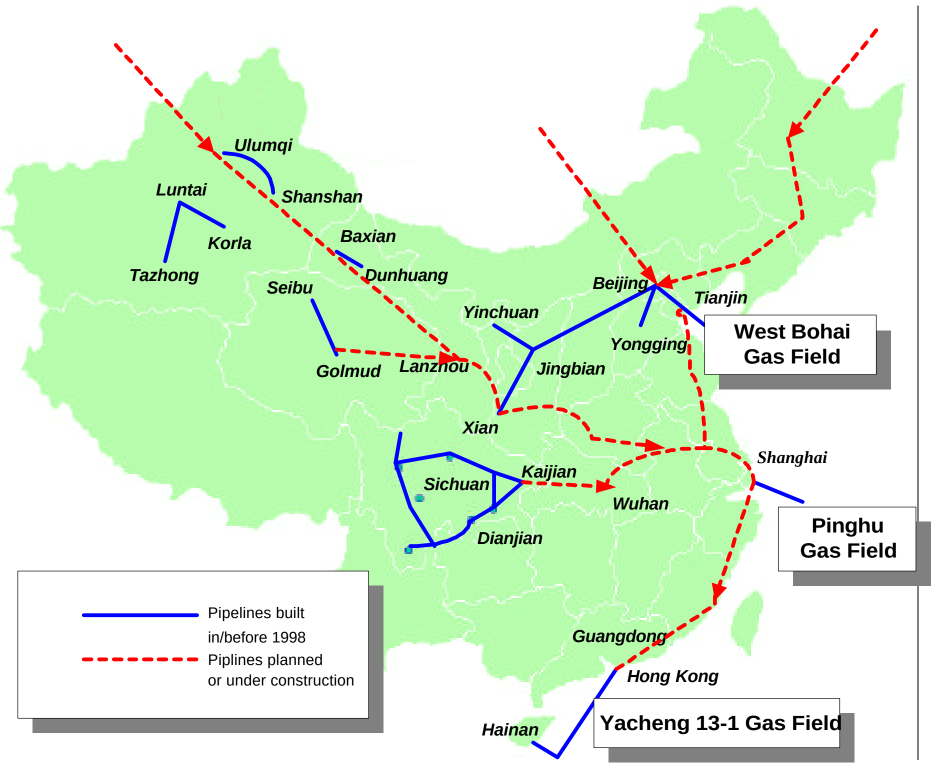
China could import natural gas via pipeline and/or as LNG. For pipeline gas, the only potential external suppliers are Russia and Central Asia. Various trans-boundary pipeline projects are under consideration as shown in Table 10. These projects are an early stage of planning, and it may take a long time to get them off ground. Because they are highly capital intensive, some or all of these projects may not eventuate in the near future.

Table 10 Potential natural gas imports from Russia and Central Asia

Pipeline route	Length (km)	Capacity (bcf/d)	Cost (US$-billions)
Ashgabad(Turkmenistan)-Xinjiang-Xi'an-Lianyungang-Cheju-Kitakyushu	7,475	1.9	22.6
Turkmenistan-Uzbekistan-Kazakhstan-Xinjiang-Yellow Sea or Shanghai	6,100	2.9	11.0
Yemai(Western Siberia)-Mongolia-Shanghai	6,500	2.9-3.7	9.0
Yakutsk(Sakha)-Changchun-Beijing-Qingdao-Seoul-Kitayushu	4,800	2.0	15.5
Kovyta(Irkutsk)-Mongolia-Beijing-Rizhao	3,365	1.9-3.1	5.9

Source: Energy Security in Northeast Asia: A Russian Perspective, (1999)

Figure 9 Natural gas pipelines in China



Source: redrawn from Williams, (1999)

The first LNG project in Guangdong province will be established with a 3 million ton per year capacity, starting operation in 2005. Several other projects are underway. As the economic viability of pipeline projects are in general distance-dependant, coastal cities in China may find LNG making more economic sense than long distance pipeline options.

Domestic natural gas pipelines have been constructed locally and they would be ultimately connected in the future according to the government plan. As shown in Figure 9, several local pipeline transmission networks were built and are likely to undergo a period of rapid expansion when demand picks up as forecasted.

MARKET POTENTIAL

Natural gas has an undisputable market potential in China. However, no one knows how much, and when natural gas will share a substantial portion of total energy consumption. China's energy policy has been traditionally oriented on domestic resources, as energy security has been a central concern for the Chinese government. As a result, the share of the imported energy in total energy consumption has been extremely low historically. Although coal consumption has caused environmental degradation, the Chinese government has been reluctant to change its energy policy direction towards market principles. However, more recently, there has been a significant shift in government policy, with growing support for deregulation and liberalization of the energy sector.

Today, China may be characterised as an economy in transition. The market plays an increasingly important role in all aspects of economic activities even though the role of government is still very important. The natural gas sector depends on government policies to a great extent and still remains under the control of state-owned corporations in terms of natural gas production and distribution.

As alluded by many experts, the power generation and residential sectors are the most attractive potential markets for natural gas. Strengthening environmental regulations and efficiency improvements in the power sector will create a situation where natural gas could compete effectively against coal.

ENVIRONMENT AS A DRIVER

Environmental quality has been the most significant driver behind the government's interest in natural gas utilization. Major cities in China have been frequently ranked high in various top 10 lists of the most polluted cities in the world. Decades of expansionary coal usage have resulted in environmental degradation, which needs urgent remediation. Environmental degradation if not properly dealt with, will drive up costs in the economy and society as a whole. In addition, further unrestricted use of coal will result in substantial damage to human health and agricultural crops.

Inter-fuel substitution from coal to natural gas appears to be the most effective measure to combat the emerging energy-related environmental problems. The Chinese government has already taken measures to curb air pollution emissions in major cities, as discussed in Chapter 4.

Table 11 Coal consumption by sector in China

	Total Consumption (million tonne)	Generation (million tonne)		Residential (million tonne)		Other (million tonne)	
		Consumption	Share	Consumption	Share	Consumption	Share
1991	1055.23	301.2	28.5%	186.8	17.7%	567.24	53.8%
1993	1140.85	368.3	32.3%	147.8	13.0%	624.74	54.7%
1995	1376.77	444.4	32.3%	135.3	9.8%	797.07	57.9%
AAGR*	6.9%	10.2%		-7.7%		8.9%	

Source: China Energy Statistical Yearbook, (1991-1996)

Note: AAGR stands for average annual growth rate

As seen in Table 11, only 32.3 percent of coal is used for power generation, while about 60 percent is distributed amongst millions of small industrial firms as fuel for heating and other uses. The energy efficiency of commonly used combustion equipment is so low that substantial atmospheric emissions occur, leading to serious environmental consequences. It would seem, therefore, that large potential demand for natural gas to replace coal exists in this sector. Moreover, there are many chemical factories that burn coal, and these could easily be served by natural gas. The industrial sector could become an important user of natural gas and contribute to improving environment quality.

POWER GENERATION

The electricity sector is a monopolistic structure, regulated by the government. The State Power Corporation owns the transmission and distribution grids, and most of the power stations. During the 1980s' China experienced an electricity supply shortage resulting in an energy policy shift towards increased power generation investment. One policy was a "rate of return guaranteed electricity price" policy, which ensured the non-risk payback for all investment made in the electricity sector. As a consequence, about ten years after the policy had been adopted, large-scale power plants were constructed and the power supply was expanded to meet the increasing demand.

As a result of rapidly increasing construction costs, and inefficiencies resulting from the government guarantee, the government is contemplating a change in electricity price regulation to discourage inefficient investment and to improve the performance of power plants. The change will lead to a regulatory regime under which electricity prices are determined by competition in the market.

Although the Chinese power industry has experienced very strong growth over a period of about 20 years, with total installed electricity generation capacity reaching 277 GW at the end of 1998 (with 1,167 TWh generated), per capita electricity consumption is still very low. Per capita installed capacity and electricity generated was about 0.22 kW and 933 kWh respectively in 1998 (see Table 12). These per capita shares were far lower than OECD and APEC averages in 1995. In a long-term view, electricity demand is likely to grow at a higher level over the next decades. Thus, electricity demand in China has a huge potential in the future, especially if the current high economic growth continues.

Table 12 Per capita electricity generation capacity comparison (for 1995)

	Population (million)	Installed Capacity (GW)	Generation (TWh)	Per Capita Capacity (kW)	Per Capita Generation (kWh)
China	1203	217.2	1007	0.18	837
APEC	2173	1544.7	6821	0.71	3139
OECD	1081	1814.0	7978	1.68	7380

Sources: 1 EDMC, (1999), IEA, (1998b), APERC, (1998c)

Based on current electricity demand-supply characteristics in China, gas-fired power plants will more likely act as peak-load plant rather than base-load from 2000 to 2010. Gas-fired power plants will be constructed in the North, Northwest, East, Shandong, and Guangdong electricity grid regions. Depending on construction progress, new gas-fired plants will be commissioned for operation between 2005 and 2010.

Uncertainties exist as to the future of natural gas consumption in the electricity generation sector. There are a number of factors that might put natural gas at a disadvantage. One is that, once the government electricity price guarantee is removed, coal could remain the preferred fuel for electricity generation, due to its ability to compete on cost. Thus a power sector without proper environmental regulations would not see expansion of natural gas as a fuel. Gas under this scenario would only be able to compete for peak-shaving.

Secondly, supply may not be able to keep up with increasing demand. The electricity sector has the potential to be able to build up demand within a relatively short period of time, while the build up of natural gas supply, reliant on (currently non-existent) large scale transmission networks, could take a long time.

NATURAL GAS AND LPG

While natural gas will supposedly compete with coal, it will likely to compete with LPG in both in industry and residential sectors. LNG has advantages over LPG in terms of safety and price-per-heat-value, while LPG has more versatility in usage, for example in the transportation sector. As seen in Table 13, LPG consumption increased rapidly of which average growth rate is 25 percent for the period of 1991-1996. Residential consumption shared 76 percent of the total consumption, of which growth rate was 28 percent for the same period. LPG market has been expanding recently eastward from Guangdong province.

Table 13 LPG Utilization (Unit: 1000ton)

	Total	Industry	Residential	Other use
1991	3009	826	2017	166
1992	3576	1084	2392	100
1993	4997	1560	2990	446
1994	5699	1660	3850	189
1995	7491	1907	5340	245
1996	9298	1745	7035	518
Average Growth Rate	25%	16%	28%	26%

Source: China Energy Statistical Yearbook 1991-1996

Due to its availability without significant capital investment in facilities, LPG has become popular for its convenience and environmental friendliness. LPG demand has grown sharply as a result and domestic supply has fallen short of the required supply since 1992. Most domestic supply comes from the newly commissioned petroleum and chemical construction projects. LPG imports have grown markedly, with the growth rate exceeding 100 percent between 1993 and 1996. The share of imported LPG has been growing rapidly in the total LPG supply market (Table 14).

Table 14 Natural Gas and LPG Supply

	Natural Gas	LPG (Domestic)	LPG (Import)
	10^8 m^3	10^4 tonnes	10^4 tonnes
1991	160.7	303.7	
1992	157.9	349.6	1.90
1993	167.66	410.14	68.12
1994	175.59	442.69	96.65
1995	179.47	540.53	232.55
1996	201.14	598.77	355.03
Average Growth Rate	4.6%	14.5%	173.3% (1993-1996)

Source: China energy statistical yearbook 1991-1996

When natural gas is introduced on a large scale, it is likely to compete with LPG in urban areas where city gas could have a relatively easy access. On the other hand in hard-to-reach areas, LPG will maintain its market share. Nevertheless the trend shown in Table 14 could serve as a reminder of potential markets for natural gas.

JAPAN

Japan possesses limited natural gas resources. Resources that do exist are located in the Niigata, Chiba and Nagano prefectures[3].

In 1969, Tokyo Gas and Tokyo Electric Power Company jointly began importing LNG from Alaska. At that time, Tokyo Gas recognised the advantages of natural gas, with its higher calorific value and lower NOx emissions[4] than fuel oil. In comparison to crude oil, the cif price/kcal of LNG was 73 percent higher,[5] due to liquefaction costs at the exporting site and transportation costs - including the cost of constructing a ship equipped with low temperature storage vessels[6]. However, at the same time the Tokyo Electric Power Company had encountered a hurdle to the construction of an oil-fired power station in Kanagawa – permission was withheld for environmental reasons. They were subsequently seeking an alternative source of fuel that would meet the environmental requirements. For these reasons, Tokyo Gas and Tokyo Electric Power Company made a joint decision to import LNG. The benefits were considered to be: (1) the achievement of economies of scale with respect to LNG transportation and terminal construction; and (2) the securing of a cleaner energy source to meet environmental requirements to reduce air pollution.

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3 It is said that people started utilising natural gas located in Niigata as early as in 1600s.

4 There is no SOx emission from natural gas (See Table 45).

5 In 1998, the LNG cif price/kcal was 31% higher than the crude oil price/kcal (EDMC, 2000).

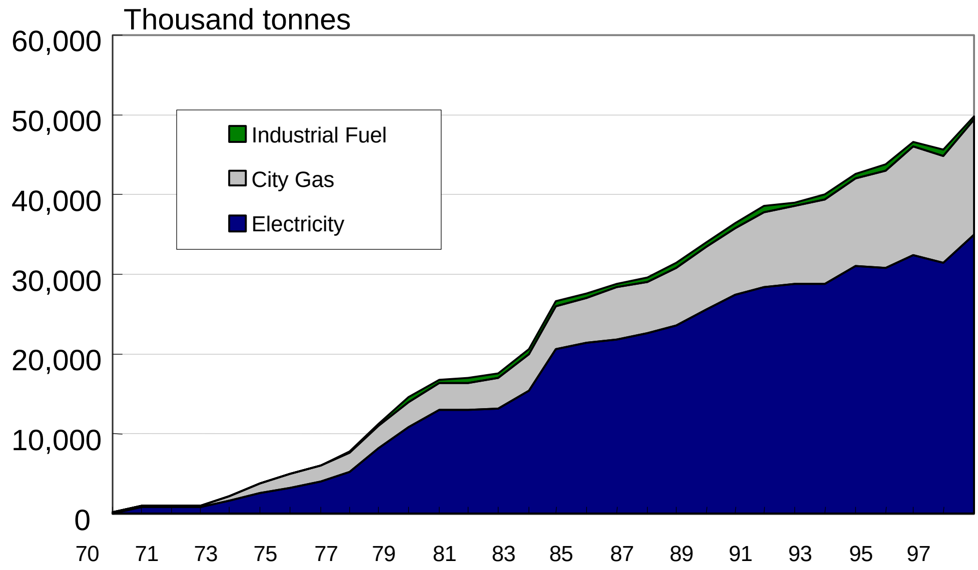
6 LNG is transported at minus 161°C.

NATURAL GAS DEMAND

Figure 10 shows natural gas demand trends by sector. Since introduction in 1996, gas consumption has grown considerably to 1998. Natural gas is used mainly for electricity generation, (70.3 percent of total usage in 1998), followed by reticulated city gas (28.3 percent) and industrial fuel (1.3 percent).

The main drivers behind the rapid increase in natural gas consumption are two fold: energy security and environment. The two oil crises in 1973 and 1980 hit the Japanese economy, including the energy sector severely. Since the oil share in total primary energy consumption accounted for 77.4 percent at the time of the first oil crisis, it drove the Japanese energy sector to seek a means of diversifying energy type as well as energy supply source. Under these circumstances, natural gas received a lot of attention as an alternative energy source for oil.

Figure 10 Natural gas demand trends of by sector in Japan



Source: EDMC, (2000)

After learning lessons from the two oil crises, the electric utilities have been looking at ways of optimising the choice of fuels.[7] This has involved fuel diversification (called “Best Mix”), that takes into account factors such as energy security, generation cost, environmental impacts and readiness of procurement. As a result, the share of oil in total electricity generation has gone from 59.2 percent in 1970 to 18.2 percent in 1997 (see Table 15). On the other hand, the share of LNG has increased from 1.3 percent in 1970 to 20.5 percent in 1997.

[7] With respect to load factor, in 1998 base load was provided by nuclear power, with a modest contribution form hydro. Coal and LNG provided middle load. Most peaking load is met by oil and hydro.

Table 15 Energy mix trends in total electricity generation in Japan

Electricity Generation Output								Unit: GWh
	Coal	Oil	LNG	Nuclear	Hydro	Geothermal	Other	Total
1970	60,100	210,200	4,500	4,600	75,400	0	0	354,800
1980	54,935	264,706	81,107	82,591	88,292	900	0	572,531
1997	196,175	187,292	211,425	319,056	89,802	3,756	21,987	1,029,493
Share								Unit: %
1970	16.9%	59.2%	1.3%	1.3%	21.3%	0.0%	0.0%	100.0%
1980	9.6%	46.2%	14.2%	14.4%	15.4%	0.2%	0.0%	100.0%
1997	19.1%	18.2%	20.5%	31.0%	8.7%	0.4%	2.1%	100.0%

Source: IEA (1999d)

The city gas suppliers, after the oil crisis, began changing the feedstock coal and naphtha (See Figure 15), to natural gas in recognition of the risk associated with reliance on oil from the Middle-East. The high calorific value[8] of natural gas contributes to an efficiency improvement.

Table 16 shows trends in Japan's primary energy supply. In 1970, the reliance on oil was high at 72 percent, while the gas share was only 1 percent. On the other hand, in 1998, the share of oil had declined to 52 percent (still highest in terms of total primary energy supply), while the share of gas had increased to 12 percent.

Table 16 Japanese primary sources of energy

Primary Energy Supply							Unit: 10^{10}kcal
	Coal	Oil	Gas	Hydro	Nuclear	Other	Total
1970	63,571	229,893	3,970	17,894	1,054	3,326	319,708
1980	67,372	262,436	24,164	20,481	18,583	4,208	397,244
1990	80,754	283,558	49,284	20,512	45,511	6,691	486,310
1998	89,278	285,267	66,995	21,447	74,777	7,143	544,907
Share							Unit: %
1970	20%	72%	1%	6%	0%	1%	100%
1980	17%	66%	6%	5%	5%	1%	100%
1990	17%	58%	10%	4%	9%	1%	100%
1998	16%	52%	12%	4%	14%	1%	100%

Source: EDMC, (2000)

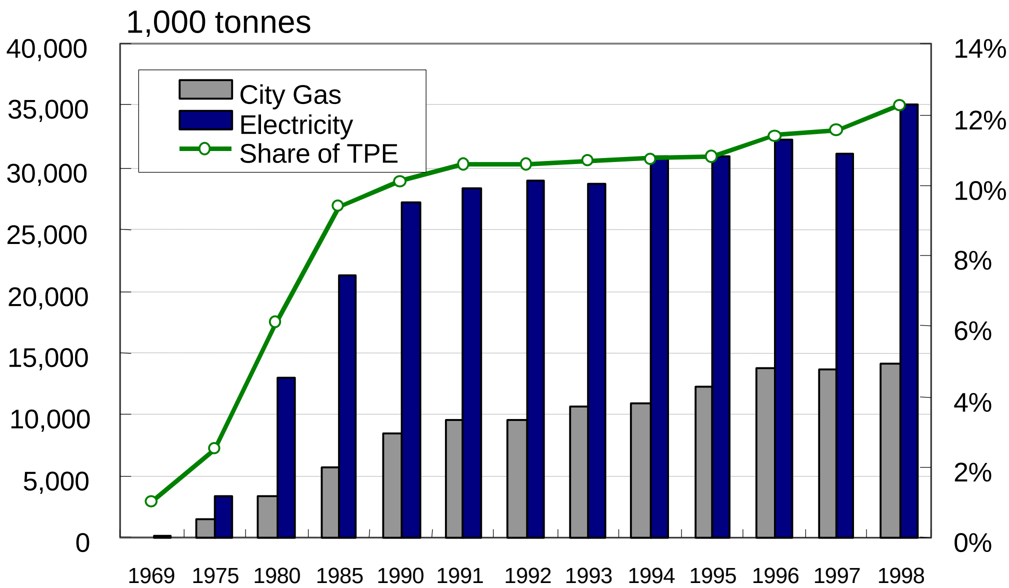
[8] The calorific value of LNG is 13,000 kcal/kg, while the calorific value of LPG is 12,000kcal/kg. (EDMC, "Handbook of Energy & Economic Statistics in Japan" (2000))

As Figure 11 shows, natural gas demand growth has levelled off. From 1980 to 1990, demand increased at 8.0 percent pa, while from 1990 to 1998 it increased at 4.0 percent pa. Natural gas remains around 10 - 12 percent of total primary energy supply. With respect to the electricity sector, from 1980 to 1990 natural gas consumption increased at 7.7 percent pa, while from 1990 to 1998 it increased at 3.2 percent pa. The reason for the change in natural gas consumption growth is two fold: change in total electricity demand and change in energy mix. From 1980 to 1990, electricity generation output (for 9 major electric utilities) increased at 4.4 percent pa, while from 1990 to 1998 it declined overall by 2.5 percent pa due to the Japanese economic slow down.

This resulted in a slow down in natural gas consumption. Also a change in electricity generation energy mix from 1990 affected natural gas consumption. Figure 12 shows the energy mix trends for total generation output, indicating an increase in the share of nuclear and coal-fired generation from 1990. From 1990 to 1998, the share of nuclear increased from 29 percent to 40 percent, while the natural gas share remained around 29 - 30 percent over the same period. Also, newly constructed coal-fired generation plants have contributed to meet the increasing electricity demand. Nuclear and coal-fired units have been installed for base load generation, while natural gas contributes as middle load and peak load generation units.

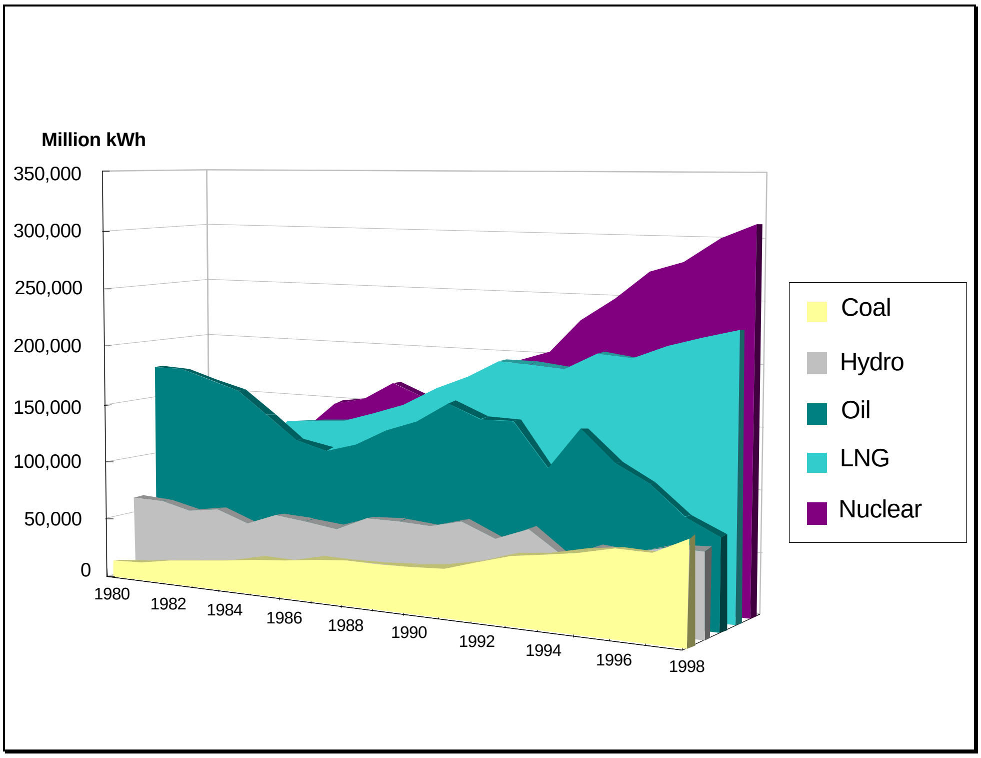
With respect to the city gas sector, from 1980 to 1990 natural gas consumption increased at 9.8 percent pa, while from 1990 to 1998 it increased at 6.5 percent pa. City gas is comprised of LNG, indigenous natural gas, coal, LPG and naphtha (See Figure 15). The Tokyo Gas Company, Osaka Gas Company and Toho Gas Company are the major players with respect to city gas supplies that dominate more than 75 percent of the market share.

Figure 11 Natural gas consumption trends by sector for Japan



Source: EDMC, (2000)

Figure 12 Electricity generation trends by fuel type for Japan



Notes: For 9 major electric utilities

Source: EDMC, (2000)

NATURAL GAS SUPPLY

Figure 13 shows natural gas supply trends by economy. In 1998, the total volume of LNG imports was 48.4 million tonnes. The largest supplier is Indonesia (18.0 million tonnes), followed by Malaysia (9.8 million tonnes), Australia (7.4 million tonnes), Brunei (5.3 million tonnes), UAE (4.5 million tonnes), Qatar (3.3 million tonnes) and Alaska (1.3 million tonnes). In terms of import share in 1998, Indonesia accounted for 36.4 percent of total imports, Malaysia 19.8 percent, Australia 14.6 percent, Brunei 10.8 percent, UAE 9.1 percent, Qatar 6.7 percent and Alaska 2.6 percent.

Figure 13   Japanese natural gas import trends by supplier

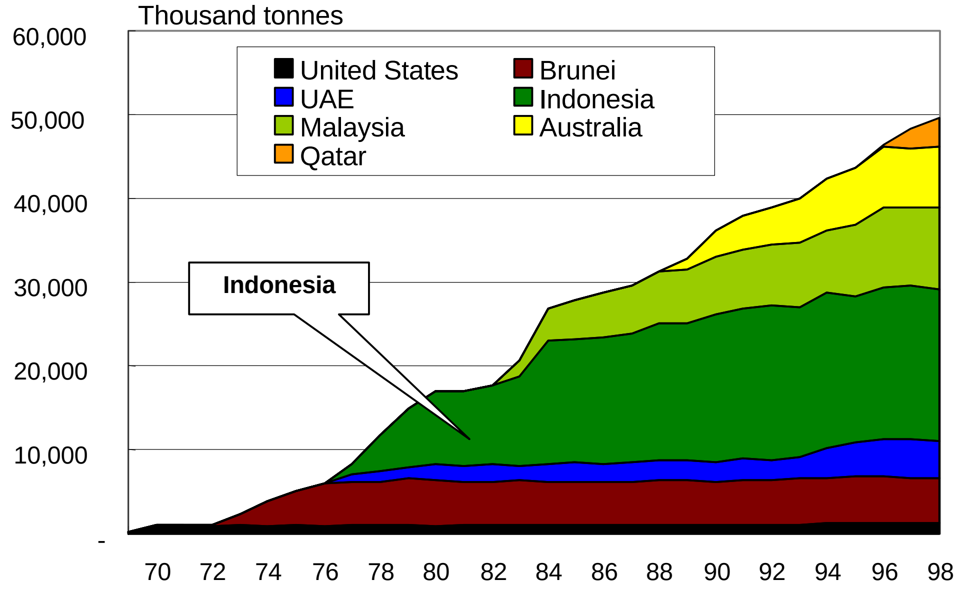


Table 17   Secured LNG sources for Japan

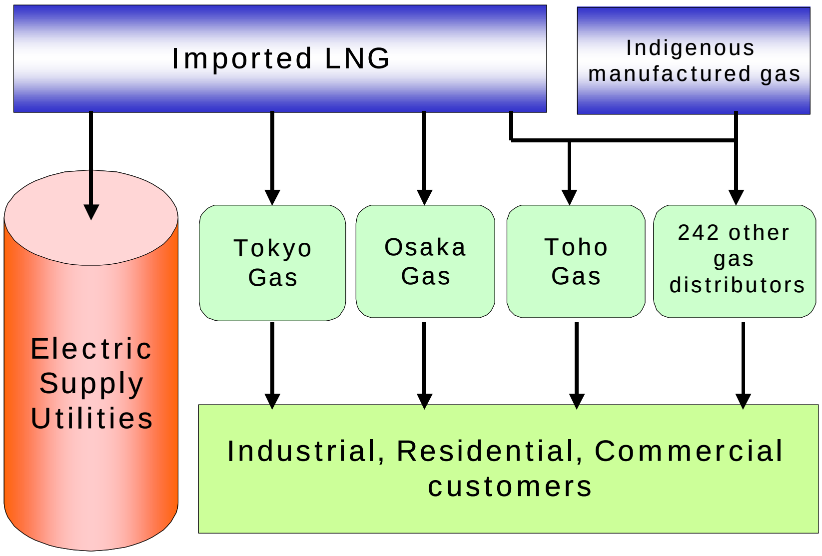
	1999	2000	2001	2002	2003	2004
Units 1,000 tonnes						
Indonesia	18,280	18,280	18,280	18,280	18,280	18,280
Malaysia	10,960	10,960	11,460	11,460	4,060	4,060
Brunei	6,000	6,000	6,000	6,000	6,000	6,000
Australia	7,330	7,330	7,330	7,330	7,330	7,330
Alaska	1,220	1,220	1,220	1,220	1,220	1,220
UAE	4,300	4,300	4,300	4,300	4,300	4,300
Qatar	5,830	6,000	6,000	6,000	6,000	6,000
Oman		660	660	660	660	660
TOTAL	53,920	54,750	55,250	55,250	47,850	47,850

Source: "Gas Binran (Annual Gas Report)"

GAS INDUSTRY STRUCTURE

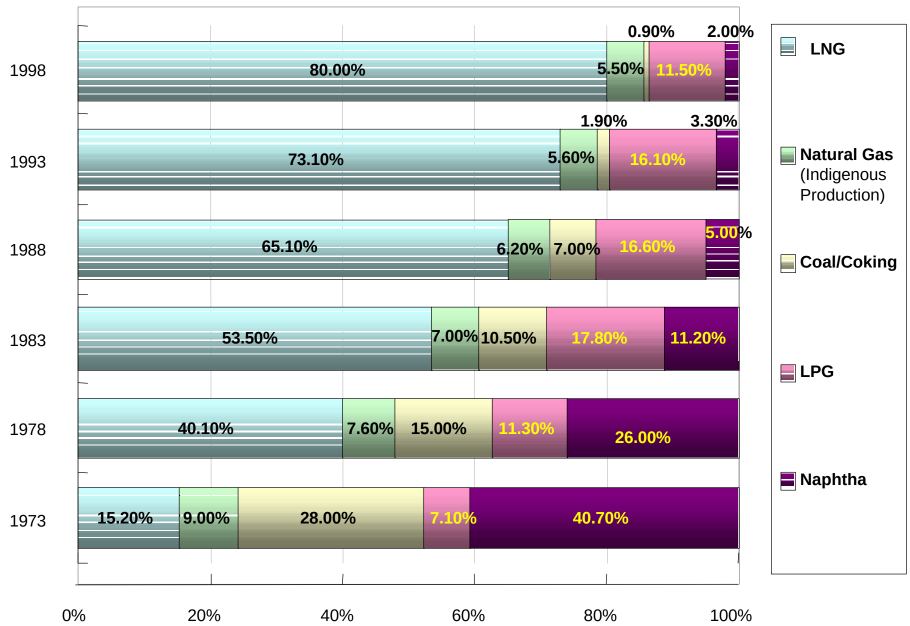
Figure 14 shows the Japanese gas industry structure. Most of them are vertically integrated companies to which regional monopoly is allowed. Three city gas companies, namely Tokyo Gas, Osaka Gas and Toho Gas, dominate more than 75 percent of the market share. There are 14 large companies, including the three companies mentioned above, 161 small and medium sized companies and 70 public corporations (IEA, 1999b). Some smaller companies buy their gas from large companies, while most of them either produce or import their own gas.

Figure 14 Structure of the Japanese gas industry



Source: IEA, (1999b)

Figure 15 Trends in composition of Japanese city gas over time



Source: Japan Gas Association

In 1998, city gas was composed of 85.5 percent natural gas, including LNG and indigenous gas, while LPG and coal accounted for 11.5 percent, and 0.9 percent respectively (See Figure 15). The Japanese government has an objective called the "Integrated Gas Family 21 Plan", aimed at increasing the share of natural gas to 90 percent by the year 2010. The three major companies, Tokyo Gas, Osaka Gas and Toho Gas use LPG only for calorific value adjustment. Of the remaining 242 gas suppliers, 42 supply LNG, 63 supply domestically produced natural gas, 16 supply LNG and domestically produced natural gas and 121 supply LPG (IEA, 1999b).

City gas is supplied to 25.07million customers, equivalent to 50 percent of all households, while LPG is delivered to 25 million customers.

LNG TRUNK LINE

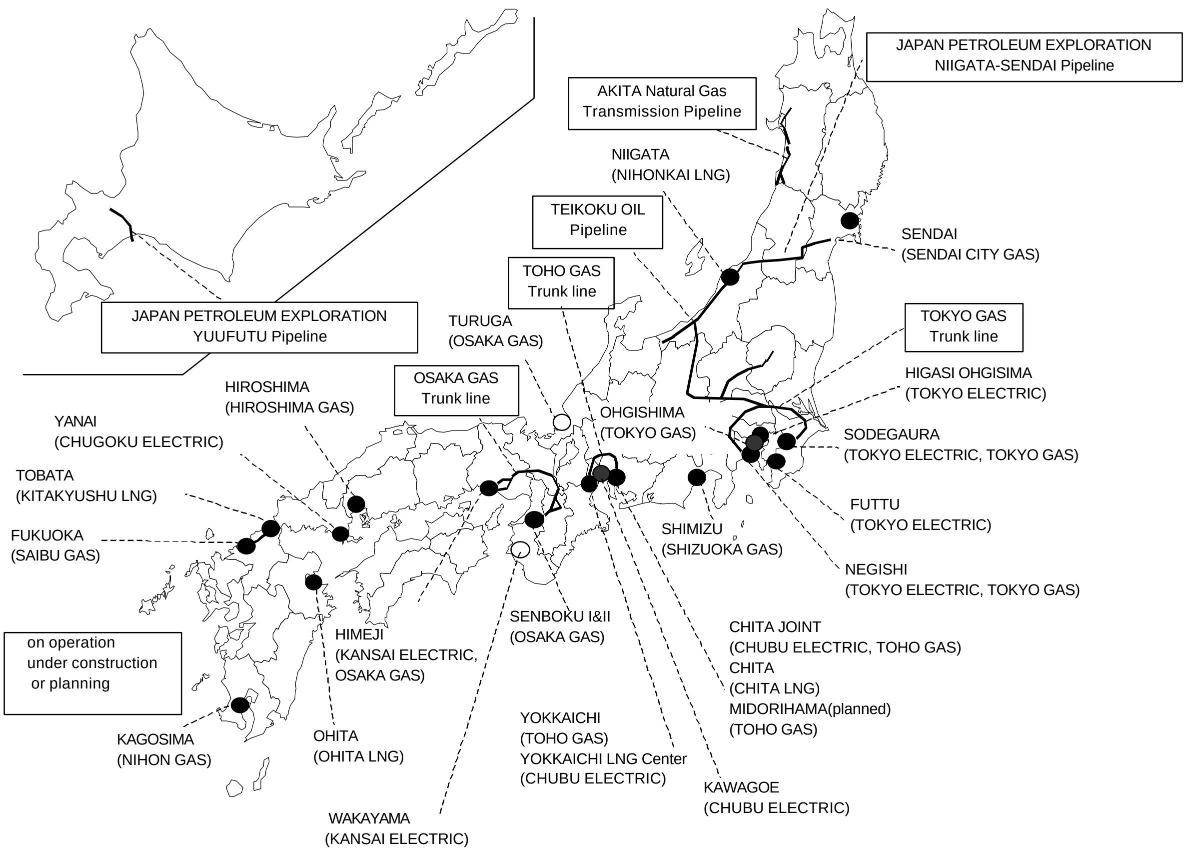
In 1997 the volume of Japanese LNG imports stood at 64.3 BCM, 57.8 percent of total world LNG trade[9]. In comparison with the total amount of gas consumed, trunk line network development remains relatively low (1,366km), with demand focused around the 22 LNG terminals,[10] as shown in Figure 15. In comparison, the total length of the trunk line network in Europe is 800,000 km, in North American it is 440,000 km and in Korea it is 1,955 km (as of 1999). The reasons for the lack of trunk line development relate firstly to the city gas and electricity industry structure. Because the firms involved are regional monopolies, with their own discrete franchise areas, they have built their own terminals to meet demand in their service areas[11]. Secondly, since the demand centres are located in large high-density cities close to the major LNG import sites in Tokyo, Nagoya and Osaka, it is difficult to build trunk lines due to the geographical constraints. There exist difficulties with respect to the value of land that has already been developed for other purposes.

9 BP Statistical Review of World Energy

10 Two terminals are now under construction.

11 Some exceptions exist such as Teikoku Oil trunk line from Niigata to Tokyo.

Figure 16 LNG Receiving terminals and trunk-lines (pipelines) in Japan



Source: The Institute of Energy Economics, Japan

AMENDMENT OF THE GAS UTILITY INDUSTRY LAW IN 1995

In 1995, the Gas Utility Industry Law was amended with respect to large industrial customers with contracted amounts of more than 2 million m^3/year. The amendments include the following provisions:

1. Gas utilities can compete outside their service areas.
2. Non-city gas suppliers are allowed to supply to large industrial customers.
3. Gas tariffs shall be free of regulation in principle. (Hasegawa, 1998).

Large volume customers, whose contract supply volume is at least 2 million cubic metres, are allowed to negotiate prices directly with suppliers. These amendments have had a significant impact on the Japanese gas sector and other energy sectors, by allowing the break down of a once very rigidly structured industry.

For example, the Tokyo Electric Power Company (TEPCO), the largest electric utility in Japan, proposed to supply gas to Ube Industries for an IPP project. TEPCO was supposed to supply gas to Ube Industries by way of the city gas company, Ohtaki gas in the Chiba Prececture. Although Ube Industries' IPP project was not selected in the second round bidding, the implication is that in the foreseeable future electric utilities will enter the gas supply business.

Table 18 Natural gas trunk-lines in Japan

	Location	Length (km)	Capacity (10,000m3/day)
Teikoku Oil Corp.	Niigata	306.0	152.2
Teikoku Oil Corp.	Niigata	67.0	113.0
Teikoku Oil Corp.	Niigata	65.0	31.9
Teikoku Oil Corp.	Niigata	64.0	33.3
Teikoku Oil Corp.	Niigata		240.0
Japan Petroleum Exploration	Niigata (Miyagi)		500.0
Japan Petroleum Exploration	Hokkaido	63.0	300.0
Japan Petroleum Exploration	Niigata	251.0	110.0
	Gunma	81.0	37.2
	Chiba	68.0	36.3

Source: The Institute of Energy Economics, Japan

AMENDMENT OF THE GAS UTILITY INDUSTRY LAW IN 1999

In 1999, the Gas Utility Industry Law was amended again. This revision attempted to pursue: (1) further opening of the gas market; (2) gain further benefits for consumers; (3) strengthen the competitiveness of utilities; and (4) minimise government involvement.

1. The revised law enlarged the eligible customer base (allowing competition for contracted amounts of more than 1 million m3/year).[12]
2. Large gas utilities will submit a wheeling code of rules to MITI so that non-city gas industries can enter the market to supply large industrial customers.
3. The MITI approval for tariff is no longer necessary in lowering the rate and promoting the benefit of customers. Instead, it must be reported to MITI.

[12] The 1995 revision confides the large industrial customers with contracted amount more than 2 million cubic metres/year.

MARKET POTENTIAL

Table 19 shows the Japanese primary energy consumption outlook to the year 2020, compiled by the Institute of Energy Economics, Japan in 1998. This outlook, from 1997 to 2020, natural gas consumption is expected to show relatively high growth compared to other energy sources. In concrete terms, the BAU case predicts that natural gas consumption will increase at 1.6 percent pa when total primary energy consumption increases at 0.6 percent pa. The relatively high increase in natural gas consumption will be driven by power generation and city gas consumption.

Table 19 Outlook for Japanese primary energy consumption to 2020

				BAU				
	Units		1997 /1990 (%)		2010 /1997 (%)		2020 /2010 (%)	2020 /1997 (%)
Coal	Million tonnes	**152**	2.2	**167**	0.7	**167**	0.0	0.4
Oil	Million kl	**324**	0.8	**336**	0.3	**331**	-0.1	0.1
Natural Gas	100 million m^3	**659**	3.9	**865**	2.1	**943**	0.9	1.6
Hydro	100 million kWh	**931**	0.3	**1,123**	1.4	**1,134**	0.1	0.9
Nuclear	10,000kW	**4,508**	5.2	**5,740**	1.9	**6,478**	1.2	1.6
Geothermal	10,000kl	**119**	14.3	**132**	0.8	**156**	1.7	1.2
New energy	10,000kl	**689**	1.5	**1,023**	3.1	**1,328**	2.6	2.9
Total	Million kl	**604**	3.1	**676**	0.9	**694**	0.3	0.6
GDP (billion Yen, 1990)		**479,835**	1.4	**564,865**	1.3	**601,950**	0.6	1.0
Energy/GDP intensity (1997=100)		**100**		**95.1**		**91.6**		
Energy/GDP Elasticity			2.3		0.7		0.4	0.6
CO_2 emission (million tonne C)		**313**	1.2	**345**	0.7	**346**	0.0	0.4
CO_2 emission (1990=100)		**109**		**120**		**121**		

Source: The Institute of Energy Economics, Japan (1998)

Table 20 Primary energy consumption outlook for Japan

	Actual	BAU	
	1997	2010	2020
Coal	16.9%	16.6%	16.1%
Oil	53.6%	49.6%	47.7%
Natural Gas	11.6%	13.6%	14.4%
Hydro	3.8%	4.0%	4.0%
Nuclear	12.9%	14.5%	15.6%
Geothermal	0.2%	0.2%	0.2%
New Energy	1.0%	1.5%	1.9%
Total	100.0%	100.0%	100.0

Source: The Institute of Energy Economics, Japan (1998)

Table 21 shows the outlook for electricity generation output. Even though the total electricity generation output will grow at a relatively low 1.1 percent pa from 1997 to 2010 due to the expected economic slow down, LNG fuel consumption will increase at 1.7 percent pa, a higher growth rate than total electricity generation output. The reason for this is expected to be fuel switching to LNG as an alternative source to oil. As shown in Table 21, the share of oil will drop from 16.0 percent in 1997, to 9.8 percent in 2010 and 7.5 percent in 2020, following the Japanese government's target to reduce the dependence on oil. This will enhance energy security and mitigate CO_2 emissions to comply with the Kyoto Protocol target. On the other hand, the share of LNG will increase from 23.6 percent in 1997 to 25.8 percent in 2010 and to 26.7 percent in 2020. In this outlook, nuclear is assumed to remain as base load with the share accounting for more than 35 percent through the forecast period, while LNG is assumed to contribute as a middle load generation source.

Table 21 Outlook for electricity generation output in Japan

	1997		2010		2020	
	Units 100 million kWh					
	Generated output	Share	Generated output	Share	Generated output	Share
Nuclear	3,191	34.8%	4,023	36.1%	4,426	37.4%
Coal	1,355	14.8%	1,957	17.6%	2,148	18.2%
LNG	2,160	23.6%	2,881	25.8%	3,159	26.7%
Hydro	952	10.4%	1,153	10.3%	1,165	9.8%
General	807	8.8%	943	8.5%	955	8.1%
Pumped	145	1.6%	210	1.9%	210	1.8%
Geothermal	37	0.4%	41	0.4%	48	0.4%
Oil	1,465	16.0%	1,091	9.8%	886	7.5%
Total	9,160	100.0%	11,145	100.0%	11,832	100.0%

Source: The Institute of Energy Economics, Japan (1998)

Table 22 shows the outlook for the consumption of city gas. Natural gas and LNG will increase at 3.0 percent pa from 1997 to 2020, as components. This forecast is based on the "Integrated Gas Family 21 Plan (IGF21)" target of city gas being composed of 90 percent natural gas by the year 2010. On the other hand LPG will be utilised as a source to adjust the calorific value, hence minimising the share.

Table 22 Outlook for city gas supply components in Japan

	BAU (million cubic metres)						
	1997	1990/ 1997	2010	1997/ 2010	2020	2010/ 2020	1997/ 2010
Natural gas /LNG	17,986 (79.0)	6.7	30,292 (90.5)	4.1	35,658 (91.0)	1.6	3.0
LPG	2,704 (11.9)	-0.5	2,522 (7.5)	-0.5	2,870 (7.3)	1.3	0.3
Others	791 (3.5)	-4.2	664 (2.0)	-1.3	645 (1.6)	-0.3	-0.9
Naphtha	199 (0.9)	-2.3	77 (0.2)	-7.0	69 (0.2)	-1.2	-4.5
Other oil products	362 (1.6)	-0.3	362 (1.1)	0.0	362 (0.9)	0.0	0.0
Coal	230 (1.0)	-9.5	225 (0.7)	-0.2	214 (0.5)	-0.5	-0.3
Total	22,765 (100.0)	5.3	33,478 (100.0)	3.0	39,172 (100.0)	1.6	2.4

Source: The Institute of Energy Economics, Japan (1998)

Table 23 shows the outlook for city gas consumption by sector. In 1997 the share of city gas consumption was as follows: residential (40.9 percent), commercial (22.7 percent) and industry (36.4 percent). From 1997 to 2020, in the residential sector where city gas is mainly utilised for cooking and hot water supply, the growth rate is expected to remain lower (0.9 percent pa) - than a total demand increase (2.9 percent pa). This is because of the expected decline in number of households. The commercial sector will increase at 4.5 percent pa over the same period because of more city gas utilisation in air conditioning and possible introduction of gas based co-generation. The industrial sector shows high demand growth during the same period (3.4 percent pa), having the highest share of total city gas consumption by 2020 (41.0 percent). The main driving force behind the expected increase in industry sector consumption is fuel switching from heavy fuel oil or LPG to city gas in boilers, taking into account further consideration to reduce CO_2 emissions and facility (boiler) turnover.

Under the given assumptions, LNG imports will rise in order to meet the demand increase. In 1998 Japanese LNG imports stood at 49.5 million tonnes, while in 2020 it is expected that LNG import will increase to about 70.0 - 87.0 million tonnes. Since current secured amounts under take-or-pay long-term contracts account for 47.5 million tonnes in 2004, Japan has to secure another 22.5 million tonnes if the current secured amount is maintained. However, faced with deregulation of the natural gas and electricity sectors,[13] there will be more uncertainties with respect to future investment decisions.

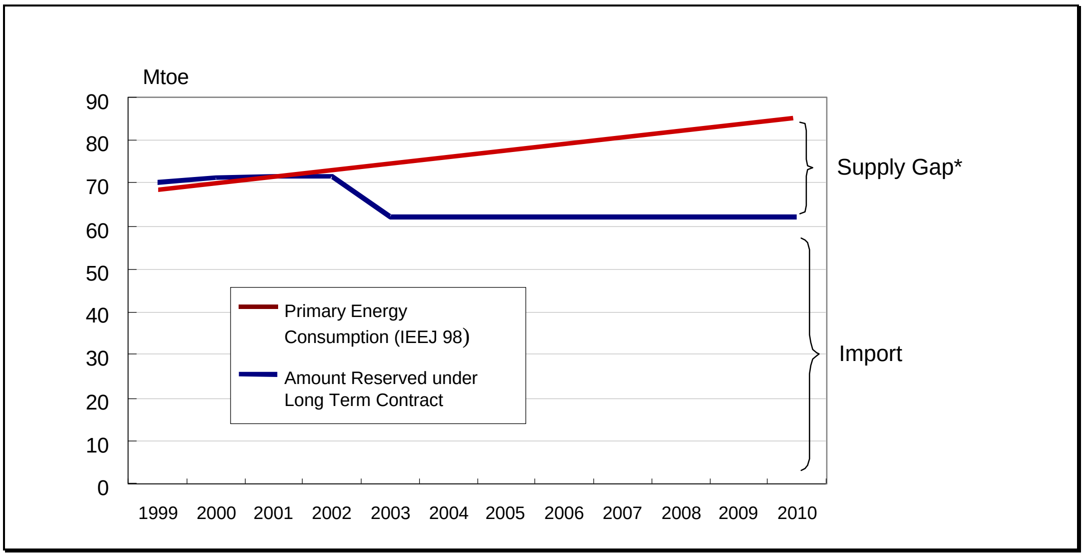
Table 23 Outlook for city gas consumption by sector in Japan

	BAU (million cubic metres)						
	1997	1997 /1990	2010	2010 /1997	2020	2020 /2010	2020 /1997
Residential	9,058 (40.9)	2.2	10,889 (33.2)	1.4	11,158 (26.3)	0.3	0.9
Commercial	5,037 (22.7)	5.3	9,076 (27.6)	4.6	13,976 (32.7)	4.5	4.5
Industry	8,071 (36.4)	10.6	12,39.2 (39.2)	3.7	17,534 (41.0)	3.7	3.4
Total	22,165 (100.0)	5.5	32,832 (100.0)	3.1	42,759 (100.0)	2.9	2.9

Source: The Institute of Energy Economics, Japan (1998)

In recognition of the need to secure natural gas, it is important for Japan to engage in natural gas development in cooperation with supply economies. Also, it is important to design a market system to facilitate natural gas utilisation, for instance, ensuring natural gas price competitiveness with respect to other fuels such as coal and oil.

Figure 17 Natural gas supply gap in Japan



Note: * Japan has to secure another 22.5 million tonnes.
Source: The Institute of Energy Economics, Japan (1998)

13 The revision of Electric Utilities Industry Law took place two times in 1995 and 1999. In 1995, the major point of amendment was regarding the entry of IPPs. The major revision of second amendment was on the partial liberalisation of electricity market took effect in March 2000 where extra-high voltage customers will be able to select their supplier.

LACK OF INFRASTRUCTURE

As seen previously, the natural gas pipeline transmission network is not well developed in Japan[14]. Also, natural gas utilisation is limited to power generation plants located close to LNG terminals or reticulation in areas located close to terminals. It makes sense to believe that construction of a nationwide natural gas trunk line will enhance natural gas utilisation. It may also create gas (LNG) to gas (pipeline natural gas) competition, provided that trunk line utilisation incorporates LNG terminal access and third party access, resulting in lower natural gas prices. However, the following estimate shows the difficulty of getting natural gas at reasonable prices even with nation wide trunk line development.

Table 45 shows the natural gas trunk line (transmission line) construction cost in Japan, estimated by Mitsubishi Research Institute. It assumes a trunk line with a total length of 5,267 km. The unit cost of construction is estimated to be 800 million Yen /km, 4~6 times as high as for Europe or the USA. The reason for the high construction cost is two fold: high safety cost, including measures to allow for frequent earthquakes, and difficulty in right of way through heavily developed city areas.

Table 24 Estimated pipeline construction costs in Japan

	Length (km)	Diameter (Inch)	Construction Cost (Million Yen)	Unit Construction Cost (Million Yen/km)
Pipeline Cost (Submarine cost)	5,267 (150)	30~40	4,201,210	798
Other Cost	-	-	24,000	-
TOTAL	-	-	4,225,210	-

Note: *Other cost includes O&M cost in Operation centre.
**Yen =1999 price

Source: Mitsubishi Research Institute (2000)

Sakhalin –1

On May 13, 1999 Exxon (USA) announced that Exxon Japan Pipeline Ltd would begin a feasibility study on a pipeline to Japan, together with Japan Sakhalin Pipeline Co., a Japanese consortium[15]. Over the next three years two feasibility studies will be undertaken, one looking at a Japan Sea route from Sakhalin to Niigata (1,300km), the other at a Pacific Ocean route (1,500km) from Sakhalin to Kanto region where the largest demand is expected.

The key issues affecting the introduction of a natural gas pipeline from Sakhalin-1 to Japan are two fold: (1) Sakhalin-2 plans to export natural gas in LNG form, hindering the potential for pipeline natural gas development, as it is not clear if the Japanese will accept both LNG and pipeline gas; (2), the Federal Government of Russia, as well as the Sakhalin local government, propose joint utilisation of a transportation system between Sakhalin-1 and Sakhalin 2.

14 The total length of natural gas trunk line in Japan is 1,366 km, while it is 4,700km in the U.K as of 1997.

15 The members of Japan Sakhalin Pipeline Co. are Itochu Co., Marubeni Co., and Sekiyu Kaihatsu Shigen. These are partners in Sakhalin-1 project as the members of SODECO.

NATURAL GAS VS NUCLEAR

According to the long-term energy supply and demand outlook of MITI in 1998, the growing electricity demand could be met by construction of 16 to 20 further nuclear power units, to meet the Kyoto Protocol target. However, the recent accident at the uranium processing plant in Tokaimura, Ibaraki Prefecture and the Chubu Electric Power Company's decision to cancel constructing nuclear power units in Ashihama, Mie Prefecture make the further development of nuclear units more difficult.

In March 2000, MITI announced that the Japanese long-term energy supply and demand outlook was to be revised, as changing circumstances has made the target set in June 1998 unfeasible If nuclear is not a major source to meet growing electricity demand, then natural gas has the potential to replace it as a source for base load generation. For this to happen, natural gas generation cost is of crucial importance.

Table 25 shows a comparison of projected generation costs for CCGT plants for selected APEC member economies. Japan has the highest generation cost followed by Korea, Canada and the USA. The Japanese costs are highest for each item. Expensive land and high safety requirements, including earthquake measures, raise investment costs. Further regulatory costs such as measures to comply with strict environmental regulations, increase investment costs as well as O&M costs.

Also, the Japanese natural gas cost is the highest compared with the other economies, as virtually all gas is imported LNG. The cost is incurred from: (1) constructing LNG terminals on expensive land, with high labour cost; and (2) the high security measure requirements. Considering the high fuel cost share in total generation cost, it is important for Japanese companies to procure natural gas at a lowest price.

Table 25 Projected generation costs calculated with generic assumptions

	Technology/Emission Control Equipment	5% Discount rate			
		Investment	O&M	Fuel	Total
Canada	CCGT	6.58	2.01	21.45	30.03
		22%	7%	71%	100%
Japan	CCGT, LNG/deNOx	14.89	7.86	56.34	79.1
		19%	10%	71%	100%
Korea	CCGT, LNG	5.78	3.35	33.39	42.52
		14%	8%	79%	100%
USA	CCGT/SCR	4.39	2.78	19.97	27.14
		16%	10%	74%	100%

Notes: 5% discount rate (US million=1996/kWh)

Source: NEA. (1998)

Table 26 provides a generation cost comparison between CCGT and nuclear power generation for Japan. A CCGT plant requires lower capital investment, and O&M costs are lower than for nuclear, however fuel cost - representing as much as 71 percent of generation costs - is higher for CCGT than for nuclear plants, making overall costs higher. Therefore, it will be vitally important for Japan to secure natural gas at a reasonable price if gas fired power plants are going to replace nuclear as a source of base load generation.

Table 26 Projected CCGT and nuclear generation costs in Japan

	Technology/Emission Control Equipment	5% Discount rate			
		Investment	O&M	Fuel	Total
Japan	CCGT, LNG/deNOx	14.89 19%	7.86 10%	56.34 71%	79.1 100%
Japan	Nuclear	24.91 43%	16.84 29%	15.71 27%	57.45 100%

Notes: (US million=1996/kWh)

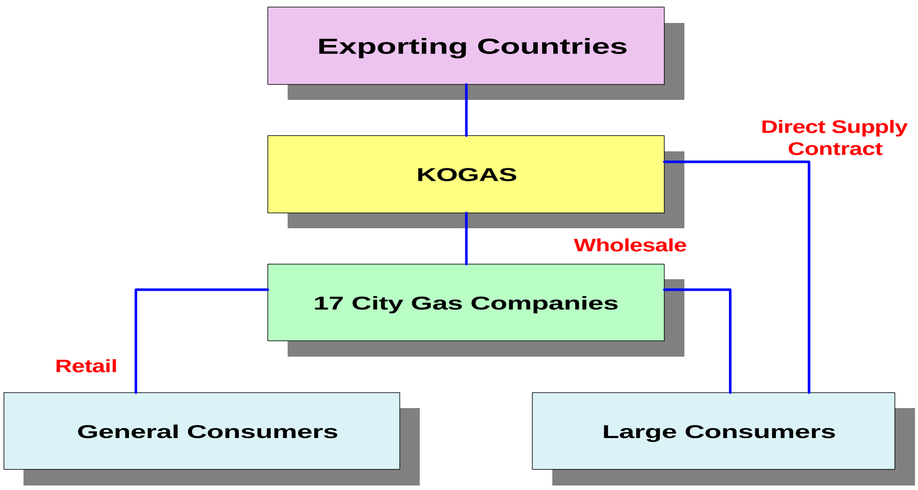
Source: NEA, (1998)

KOREA

Korea's natural gas industry began in 1983, with the establishment of the government-owned import and wholesale monopoly, the Korea Gas Corporation (KOGAS), and the LNG import contract from Indonesia. The first LNG cargo arrived at Pyongtaek terminal in October 1986 and was supplied to the Korea Electric Power Corporation (KEPCO) for power generation from November in that year.

The monopoly structure has been maintained until now, but the government announced a plan to deregulate the natural gas industry and privatise KOGAS within a few years.

Figure 18 Structure of natural gas industry in Korea



Natural gas for power generation accounted for 95 percent of total consumption in 1987, but its share in 1998 was less than 50 percent of total consumption. For city gas use, natural gas began to be supplied to the metropolitan Seoul area in February 1987. Since then, the volume has been growing very rapidly, at an average rate of 42.5 percent, and the area served has been widened continuously, covering more than forty cities and counties across the country as of the end of 1998 with the expansion of a nationwide natural gas pipeline network. (Figure 19).

Figure 19 Natural gas pipeline network in Korea

Source: KOGAS' website: http\\www.kogas.co.kr

LONG-TERM DEMAND AND SUPPLY

It is projected that future consumption will be led by the industrial and residential sectors, with the former showing an expected growth rate of 28.8 percent until the beginning of the next century and the latter showing 20.6 percent growth rate during the same period. The power generation sector is anticipated to show a relatively low rate of growth at 16.7 percent in the same period in spite of the large growth in absolute terms. However, it is very likely that the demand in this sector will grow much faster than projected due to the opening up of import restrictions for large volume consumers, and the introduction of competition in the power generation sector.

Korea relies almost totally on imported LNG, as there are no indigenous gas reserves, except for a very small volume found offshore in the East Sea. Therefore, it is important for Korea to secure natural gas supply from various sources on economic terms. At the moment, Korea's LNG import heavily depends on Southeast Asia, particularly Indonesia and Malaysia. However, import sources will be diversified to other areas including Qatar, Oman and Canada. The Korean government is now considering further diversifying natural gas import sources, to include East Siberia, which will, if the project proves to be economic, supply natural gas in pipeline form. These projects are to be developed with the participation of Korean capital and technology, being examples of the strategies employed to secure gas sources on economic terms and to help Korean firms gain competitiveness in the world energy market.

NATURAL GAS UTILIZATION

Natural gas is used mainly for power generation and for reticulation as city gas. Natural gas for power generation accounted for 95 percent of total consumption in 1987, but this share had declined to less than 50 percent in 1996. Natural gas began to be reticulated to the metropolitan

Seoul area in February 1987. Since then, the city gas volume has been growing rapidly, at an average rate of 42.5 percent, and the service area has been widened continuously, covering forty cities and counties across the economy as of the end of 1996.

KOGAS, currently the sole owner and operator of LNG receiving terminals at Pyongtaek and Inchon, is operating ten storage tanks with 100,000 kilolitre capacity each. The Pyongtaek terminal has seven tanks and Inchon three, added to the supply system in November 1996. Despite its short history, Korea's natural gas industry is experiencing exciting changes, not only in terms of the market size, but also through the introduction of competition in the wholesale sector. The government has opened doors to large volume consumers (POSCO[16] only at the moment, but many other industrial/power generation users can import LNG from 2001).

In 1999 natural gas consumption has been estimated to reach 12.65 Mt in total, consisting of 7.88 million tonnes of city gas, and 4.77 Mt for power generation. Despite the financial crisis in 1997 the demand has bounced back within a relatively short period of time.

Table 27 Natural gas utilization in Korea

	Consumption					Stock
	Total	Generation	District Heat	Town Gas	Own-Use	
	Unit: LNG 1,000tonne					
1987	1620.7	1536.7		75.4	8.6	126.2
1988	2094.1	1905.2		183.9	5.0	94.6
1989	2026.5	1669.6		349.3	7.6	84.2
1990	2329.2	1741.3		575.5	12.4	46.1
1991	2694.3	1800.1		879.2	15.0	110.0
1992	3524.0	2224.9		1256.2	42.9	66.8
1993	4402.4	2517.9		1847.5	37.0	97.2
1994	5860.3	3214.6	114.4	2451.1	80.2	156.9
1995	7087.0	3412.0	150.0	3417.0	108.0	103.0
1996	9374.5	4448.9	173.5	4581.1	171.0	368.9
1997	11378.8	5197.6	179.0	5770.2	232.0	604.9
1998	10,644.5	4,029.8	159.6	6,232.9	222.2	527.0

Note: * Numbers are estimates.

Source: KEEI, (1999)

The growth rate in energy consumption in the Republic of Korea had been more than 10 percent over the last decade. In 1998, total energy consumption showed a negative growth rate due to recession. As economic conditions improved in the second half of 1998, energy demand began to bounce back in 1999, and is likely to resume a moderate growth.

16 Pohang Steel Corporation is the largest steel manufacturer in Korea.

Table 28 Major energy indicators for Korea

		1990	1994	1995	1996	1997	1998
Energy Consumption (1,000 TOE)	Primary	93,192	137,235	150,437	165,212	180,638	165,932
	Final	75,107	112,206	121,962	132,033	145,773	132,118
Per Capita Energy Consumption (TOE/Person)		2.17	3.09	3.35	3.63	3.93	3.57
Dependency on Imported Energy (%)	Nuclear included	87.9	96.4	96.8	97.3	97.6	97.1
	Nuclear excluded	73.7	85.7	85.6	86.1	86.9	83.6
Share of Petroleum in Primary Energy Consumption		53.8	62.9	62.5	60.5	60.4	54.6
Share of Electricity in Final Energy Consumption		10.8	11.2	11.5	11.9	11.8	12.6
Energy Price Index		90.3	99.4	100	102.9	107.1	104.5
Energy/GDP Ratio (TOE/Million Won)		0.36	0.40	0.40	0.41	0.43	0.42
Economic Growth Rate (%) (GNP)		9.5	8.4	8.7	6.9	5.0	- 5.8
Growth Rate of Primary Energy Consumption (%)		14.1	8.1	9.6	9.8	9.4	- 8.1

Source: KEEI, (1999)

PROJECTED ENERGY DEMAND FOR KOREA

Table 29 Energy demand projections by source.

	1997	2000	2010	2020	Growth Rate(%)		
	(Mtoe)	(Mtoe)	(Mtoe)	(Mtoe)	97-2000	2000-10	2010-20
Petroleum	103.4	102.2	131.4	150.2	-0.4	2.5	1.3
LNG	14.8	18.7	27.3	44.7	8.1	6.8	5.0
Anthracite	2.0	2.0	1.6	1.1	0.3	-2.2	-3.3
Bituminous	32.8	37.1	51.1	60.2	4.2	3.2	1.7
Hydro	1.3	1.2	1.2	1.2	-4.0	0.2	0.0
Nuclear	19.3	25.1	41.2	61.2	9.2	5.1	4.0
New & Renewable	1.3	0.9	1.4	2.1	-12.2	4.7	3.8
Total	175.0	182.8	255.3	320.7	1.5	3.4	2.3

Source: KEEI, (1998)

Natural gas demand reached 11.4 million tonnes in 1998, roughly 2.5 million tonne less than projected before the crisis. The lion share of reduction came from the power generation sector, as a result of lowered electricity demand and less dispatch of gas-fired power plants due to high fuel cost. City gas consumption was less affected as the residential/commercial sector consumption showed a steadily increase as the nationwide trunk line extended and, at the same time, natural gas is becoming more price competitive than other fuels. In addition, the government is now seeking a new incentive mechanism to promote natural gas consumption in the industrial sector.

The actual figure for natural gas demand depends critically on negotiations between KEPCO and KOGAS, the outcome of which will determine planned consumption for power generation. The negotiation is important in that KOGAS and KEPCO have different interests with respect to natural gas consumption. KEPCO has no incentive to build additional gas-fired power plants for peak shaving as demand for electricity has fallen substantially since the onset of the crisis, while KOGAS wishes to maintain a favourable load factor because of purchasing contracts and storage utilization.

Carefully examining past records of natural gas demand and key macro indicators, it can be concluded that if the financial crisis is a temporary one, natural gas demand growth will pick up within a couple of years. Then demand growth should follow its previous growth path, with roughly two to three million tonnes less per year. However, there are many factors, e.g. GDP growth rates, which could prove this tentative projection wrong.

ENERGY SUPPLY IN KOREA

CURRENT ENERGY SUPPLY SOURCES

Energy has been the mainstay of economic development in Korea for the last 30 years. Oil has been the most important fuel, comprising about 60 percent of total primary energy. Oil has for the most part, been imported from the Middle East. As shown in Table 30 below, Saudi Arabia has been the major exporter to the Korean market historically, and remains so. The dependency on crude oil supply from the Middle East was around 70 percent in the 1990s. The Korean government, which went through oil supply disruptions in 1970s and 1980s, made various attempts to diversify its oil importing sources, but didn't achieve significant success. Nevertheless dependence on the Middle East has declined, from 72.2 percent in 1993 to 66.7 percent in 1997.

Table 30 Korean crude oil imports

YEAR	1993 (1,000 Bbl)	1995 (1,000 Bbl)	1997 (1,000 Bbl)
Saudi-Arabia	172,413	226,863	267,888
Kuwait	29,334	25,233	55,091
Iran	76,057	68,314	82,192
UAE	57,576	70,536	127,395
Oman	69,557	55,131	50,197
Ecuador	17,702	18,456	10,901
Malaysia	27,370	13,339	16,968
Brunei	12,950	11,938	12,787
Indonesia	34,677	31,367	40,965
Others	62,927	03,768	209,030
TOTAL	560,563	624,945	873,414
(1,000 Kl)	89,120	99,355	138,895

Source: KEEI, (1998)

Table 31 shows the LNG supply sources for the years 1993, 1995 and 1997. The major supply source will shift from South East Asia to the Middle East beginning in 1999, when the first cargo from Oman is to arrive. For the next 20 years the Middle East will be the major LNG supplier to Korea as Qatar will supply about 4.9 million tonnes of LNG a year from 2002. The combined total amounts of LNG contracted from Qatar and Oman will reach 8.9 million tonnes a year from 2002. Thus Korea's dependence on the Middle East for energy supply is likely to remain at the current level despite the decrease in oil import from the region.

Table 31 Korean LNG imports

YEAR	1993 (thou. Ton)	1995 (thou. Ton)	1997 (thou. Ton)
Indonesia	4,108	5,258	6,848
Malaysia	290	1,039	4,028
Brunei	-	707	753
Australia	56	57	-
TOTAL	4,454	7,060	11,629
Amounts (Million$)	774	1,230	2,300

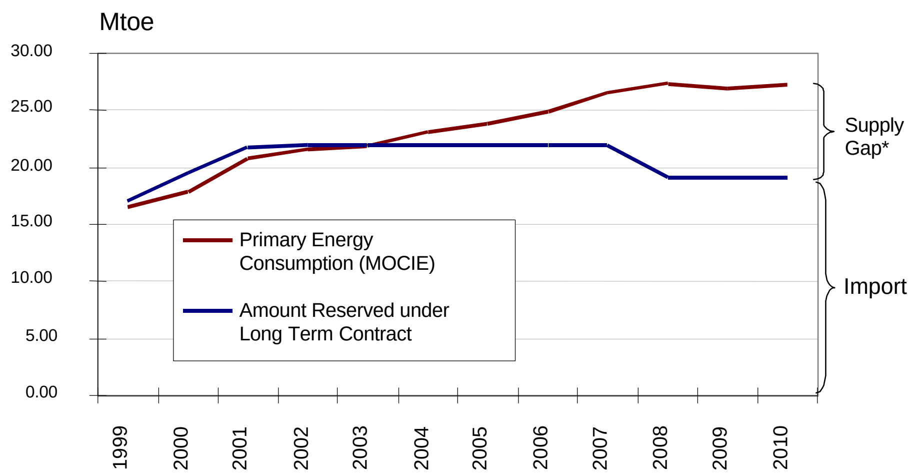
Source: KEEI, (1998)

Table 32 LNG supply sources in Korea

	1999	2000	2005	2010
	Units: 10,000 LNG tonne			
Required import	1,266	1,381	1,830	2,097
Secured	1,314	1,504	1,698	1,468
Indonesia	530	530	530	300
Malaysia	200	200	200	200
Oman		200	406	406
Qatar	66	342	492	492
Brunei	70	70	70	70
Mid contract	359			
Adjusted quantity	90	162		
To be secured	-	-	132	629

Source: Compiled by the author from information obtained from KEEI and Korea Gas Corporation.

Figure 20 Korean natural gas import potential



Note: * Supply Gap: 8.18 MTOE or 6.62 million LNG tonne in 2010

** The forecast conducted by the Ministry of Commerce, Industry and Energy (MOCIE) is used

MARKET ASSESSMENT

Natural gas is a versatile fuel, and can be used in a number of applications by residential, commercial, and industrial users. In the residential and commercial sectors, natural gas is used mostly for cooking and space heating. In the industry sector, it is used as a boiler fuel, in direct heat processes, or as a chemical feedstock. Natural gas is also used for electricity generation. The competitive position of natural gas *vis-à-vis* other fuels varies widely with end-use processes in which it is used. It is also considerably affected by the social costs associated with the relative environmental impacts of each fuel. The potential economic use of natural gas in Korea is limited compared to most other natural gas consuming economies as it is considered a premium fuel.

Although natural gas currently accounts for only a small portion of Korea's energy balance (about 8 percent of primary energy consumption in 1997), it is already being used in a wide range of end-use applications. In some cases natural gas use is driven by price, but in other cases, convenience-of-use or quality offered by gas is the most relevant factor from the customer's perspective, while the current natural gas use is often dictated by regulations or other government fiat. Thus much of the gas use in large cities like Seoul is dictated by government regulations related to air quality concerns. Also, much of the gas network construction to date has been made possible by the availability of subsidized government funding. Similarly, while KEPCO is presently the major consumer of LNG, this is mostly as a result of its having been instructed to play the role of the "swing" consumer until natural gas could penetrate other end-use markets, so as to insure full use of contracted natural gas (LNG) quantities. Finally, again out of environmental concerns, all oil-fired power plants in the metropolitan area had to switch to natural gas, starting in 1991. Notwithstanding the rationale and merits of these government interventions in the process of gas allocation, an economic assessment of natural gas utilization, compared to other fuels is necessary in order to understand the future demand for natural gas.

Usually economic assessments of natural gas vis-à-vis other fuels in each sector are done in terms of annualised financial and economic costs measured based on the annual energy requirements of each type of consumers (MMbtu/year). These costs are built up from a point of energy production or import to a point of end-use. Adding up these costs allows calculation of the implicit "net-back value" of gas at a particular point in the gas chain. In practice, for residential, commercial and industrial consumers, the fuel cost comparison is made at service connections. The total economic cost of meeting any particular energy end-use is the sum of the economic costs of importation or production of energy commodities and those of taking them to a point of consumption. Cost comparison between natural gas and a competing fuel must also include the costs associated with end-use technologies (stove, heater, boiler, etc.) to reflect different end-use efficiencies, if any. Also costs associated with service lines, regulators and internal piping must also be taken into account.

Energy related taxes are closely linked to social costs arising from the use of a particular energy source and must be appropriately reflected in the cost comparison. If the above methodology is going to be adopted, technological, economic, and institutional information have to be readily available assess the potential marketability of natural gas. The following is a qualitative analysis of the comparative advantages of natural gas drawn from a cost comparison among competing fuels across different sectors.

In general, the household sector is looked upon as a premium market for natural gas. Energy consumption in the household sector is mainly for cooking and space heating. LPG and natural gas are mainly used for cooking, while other fuels such as electricity and kerosene are commonly used for space heating. Since energy consumption for cooking is relatively small, natural gas is not economical if used only for cooking in stand-alone houses. Conversely if these houses already use natural gas for space heating, there is no reason for them to use LPG for cooking. However, large volume consumers such as apartment complexes using central or district heating systems may as well use natural gas for cooking since natural gas service lines can easily be extended to them. Therefore markets for natural gas for cooking are clearly differentiated by type of house and the regional supply feasibility of city gas.

For space heating in the household sector, light heating oil (kerosene, diesel), heavy heating oil, LPG, and district heating compete against natural gas. In case of apartment complexes, natural gas seems to have definite advantages: reasonable supply cost and low environmental impacts (assisted by regulations imposed by the government). For stand-alone houses, natural gas has to compete against light heating oil due to an additional, service connection charge paid by consumers. However the additional cost could be incorporated in real estate (house) prices. Competition between these two fuels relies on unit fuel cost and efficiency. For stand-alone houses, taxation measures have been implemented for environmental purposes (instead of regulations), for the latter is hard to enforce in this case. With a lower tax levy for natural gas than for other fuels, the economic feasibility of natural gas can be determined by pipeline economics of city gas. The pipeline economics of stand-alone houses is usually not as good as that for apartment complexes due to lack of household density.

Natural gas consumption in the commercial sector has been increasing in both absolute and relative terms. Some restaurants use natural gas for cooking, but a significant number are still using LPG. Large restaurants with high energy intensity would be better off with natural gas, due to large volume usage, while for small ones LPG may be a more attractive option. In recent years an increase in natural gas consumption has been observed in this sector as consumers feel that natural gas supplied by pipeline is more convenient than bottled LPG.

For space heating in the commercial sector, heavy fuel oil use has been regulated. Moreover heavy fuel oil attracts higher taxes than natural gas, and tends to more expensive overall. In addition, as consumption volume rises, natural gas would become more competitive.

Natural gas is competing with night-time electricity for space cooling. As part of a demand side management initiative, the government offered incentives for the use of night-time electricity in the form of low electricity tariffs. The incentive put natural gas at a disadvantage. However, a new government measure for promoting gas-fired cooling systems is improving market conditions for natural gas.

In the industry sector natural gas is in competition with heavy and light fuel oil and LPG. The consumption record seems to indicate that light fuel oil and LPG are in a better position and heavy fuel oil is in a worse position than natural gas. The main reason behind the current market condition is that fuel prices are determined by volume only, regardless of the amount of annual consumption and load factor. Thus under the current pricing structure it would be difficult for natural gas to become competitive. However natural gas is extremely competitive in certain regions where strict environmental regulations are enforced.

Currently the power generation sector consumes about half of the total natural gas. In this market, there are three main feedstock fuels including bituminous coal, heavy fuel oil, and natural gas. Natural gas is the least preferred because of cross subsidy from the power generation sector to the city gas sector. Once the subsidy is reduced or removed, natural gas will become more competitive than heavy fuel oil. In the long run if environmental cost is reflected in fuel prices, natural gas would gain increasing share in the market.

Table 33 Long-term outlook for LNG demand in Korea by sector (1998)

	For City Gas Use				For power Generation			Grand Total
	Household	General	Industry	Total	KEPCO	IPPs	Total	
				Units 1000 tonnes				
97 Actual	3768 (65.3)	1111 (19.3)	891 (15.4)	5770 (100)	5377	0	5477	11547
1998	4490	1256	1030	6776	4318	0	4318	11094
1999	4903	1453	1585	7941	4796	0	4796	12737
2000	5220 (58.5)	1575 (17.6)	2132 (23.9)	8926 (100)	4667	785	5452	14378
2001	5645	1765	2496	9906	5647	1004	6651	16557
2002	5942	1919	2821	10683	5897	743	6640	17323
2003	6182	2086	2989	11253	5971	201	6172	17428
2004	6449	2227	3175	11851	5812	212	6024	17875
2005	6754	2375	3388	12518	5946	214	6160	18678
	(54.0)	(19.0)	(27.1)	(100)				
2006	7062	2511	3591	13164	6027	225	6252	19416
2007	7338	2645	3811	13844	5913	231	6144	19988
2008	7722	2757	4055	14534	5803	234	6037	20571
2009	8063	2847	4320	15231	5267	237	5504	20735
2010	8399	2933	4611	15943	5672	241	5913	21856
	(52.7)	(18.4)	(28.9)	(100)				
2011	8698	3011	4819	16528	6168	244	6412	22940
2012	8987	3088	5004	17078	6309	246	6555	23633
2013	9268	3158	5216	17642	6689	249	6938	24580
2014	9543	3226	5438	18207	7152	252	7404	25611
2015	9918	3320	5671	18909	7660	254	7914	26823
	(52.5)	(17.6)	(30.0)	(100)				
Growth rate(1997~2015)								
	5.2%	5.9%	10.2%	6.4%	1.9%			4.7%

Note: 1) Numbers in ( ) indicate the composition rate

2) Cogeneration use is included in general use.

Source: Korea Gas Paper, weekly (1998)

Table 34 Long-term outlook for LNG city gas by sector in Korea (1998)

	Household Use			General Use					
	Cook	Heating	Total	Com-mercial	Business Building			Co-gen	Sub
					Heating	Cooling	Total		Total
	Units 1000 tonnes								
97 Actual	457	3311	3769	116	687	118	805	190	1111
1998	569	3921	4490	138	740	130	869	250	1256
1999	612	4290	4903	157	848	159	1007	289	1453
2000	667	4552	5220	177	883	174	1057	340	1575
			(58.5)						(17.6)
2001	728	4917	5645	202	1005	179	1185	379	1765
2002	775	5168	5942	221	1087	191	1279	420	1919
2003	821	5361	6182	240	1164	203	1367	479	2086
2004	867	5581	6449	259	1235	213	1449	519	2227
2005	921	5833	6754	278	1303	223	1527	570	2375
			(54.0)						(19.0)
2006	964	6098	7062	297	1368	233	1601	613	2511
2007	1007	6382	7388	315	1430	242	1672	657	2645
2008	1049	6673	7722	334	1489	250	1739	685	2757
2009	1089	6974	8063	352	1544	258	1802	693	2847
2010	1128	7271	8399	370	1596	265	1861	701	2933
			(52.7)						(18.4)
2011	1160	7538	8698	387	1646	272	1918	706	3011
2012	1190	7796	8987	405	1693	279	1972	711	3088
2013	1219	8049	9268	422	1739	285	2024	711	3158
2014	1247	8296	9543	440	1784	291	2075	711	3226
2015	1273	8645	9918	462	1850	297	2147	711	3320
			(52.5)						(17.6)
	Growth rate (1997~2015)								
	5.8%	5.5%	5.5%	8.0%	5.7%	5.3%	5.6%	7.6%	6.3%

Source: Korea Energy Economics Institute(1998)

CHAPTER 3

SUPPLY POTENTIAL

While sufficient demand is of primary concern in the development of gas infrastructure, an adequate reserve base to supply those markets over many years is also a key consideration. This chapter will review reserve and production trends in China, Southeast Asia and Australia, and examine gas reserve estimates and supply potential in Russia.

China is the major gas producer in East Asia, although Chinese Taipei and Japan produce small amounts of gas. Japan imported more than 96 percent of its gas supply in 1995 and its dependence is not expected to decrease over the forecast period. Gas production in Chinese Taipei is expected to increase but to remain less than 30 percent of supply throughout the forecast period.

There are several major natural gas producers and LNG exporters targeting Northeast Asia. Brunei, Indonesia, and Malaysia, along with Australia, are major supplies of LNG to East Asia. Thailand is a gas producer but also an importer. The Philippines is just beginning to produce small amounts of natural gas.

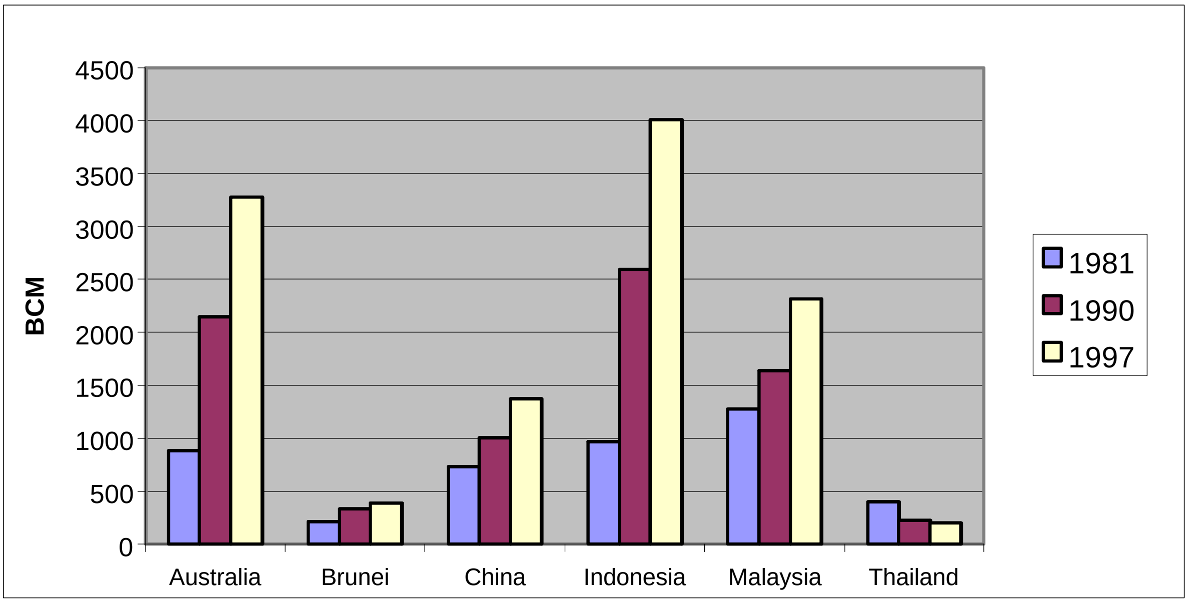
RESERVE AND PRODUCTION TRENDS

The natural gas reserve base has increased steadily in Asia. Reserves in the major producing economies (Australia, Brunei, China, Indonesia, Malaysia, and Thailand) increased from 4.5 trillion cubic metres (TCM) in 1981 to 11.6 TCM at the end of 1996. During this same period, natural gas production totalled 1.7 TCM. Reserves were discovered and proven at a sufficient rate to not only replace production but to more than double the reserve base over this 15-year period. The reserve to production ratio for these six economies was 83 years at the end of 1981 and remained about 59 years at the end of 1996. Indonesia has the largest natural gas reserves followed by Australia (Figure 21).

The major constraint to the development of natural gas in Asia is not an insufficient reserve base but rather the lack of infrastructure for transporting the gas to markets. LNG has been the dominant means of moving gas to consuming areas. LNG, however, requires very large-scale facilities and large reserves in a close proximity. Small, isolated fields are not economic to develop. As a result, natural gas development in Asia has centred around major LNG projects. Recent expansions of several of these facilities have increased LNG capacity in Indonesia, Malaysia, and Australia.

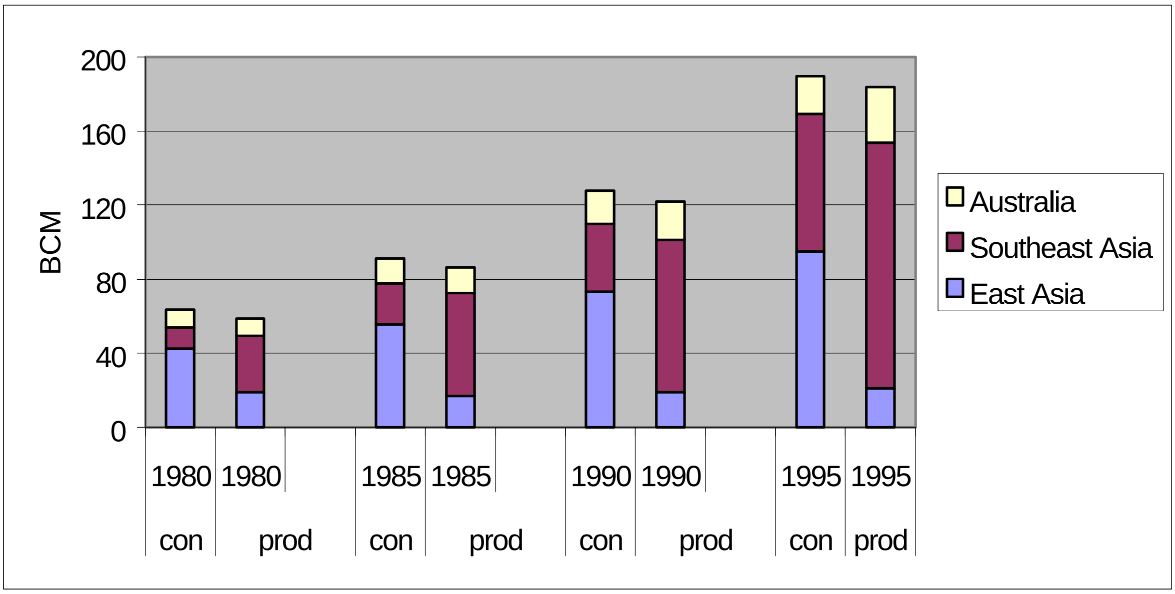
To a large extent, the development of natural gas resources in Asia has been driven by the demand for natural gas. In Figure 3-2, the increase in consumption in East Asia, Southeast Asia, and Australia is compared with the increase in production. Southeast Asia and Australia have increased production to keep pace with expanding demand, occurring primarily in East Asia. Production in the six major producing economies increased 3.3 fold from 54 BCM (45 Mtoe) in 1980 to 181 BCM (150 Mtoe) in 1995. Indonesia is the largest producer followed by Malaysia (Figure 23).

Figure 21 Natural gas reserves



Source: CEDIGAZ, (1999).

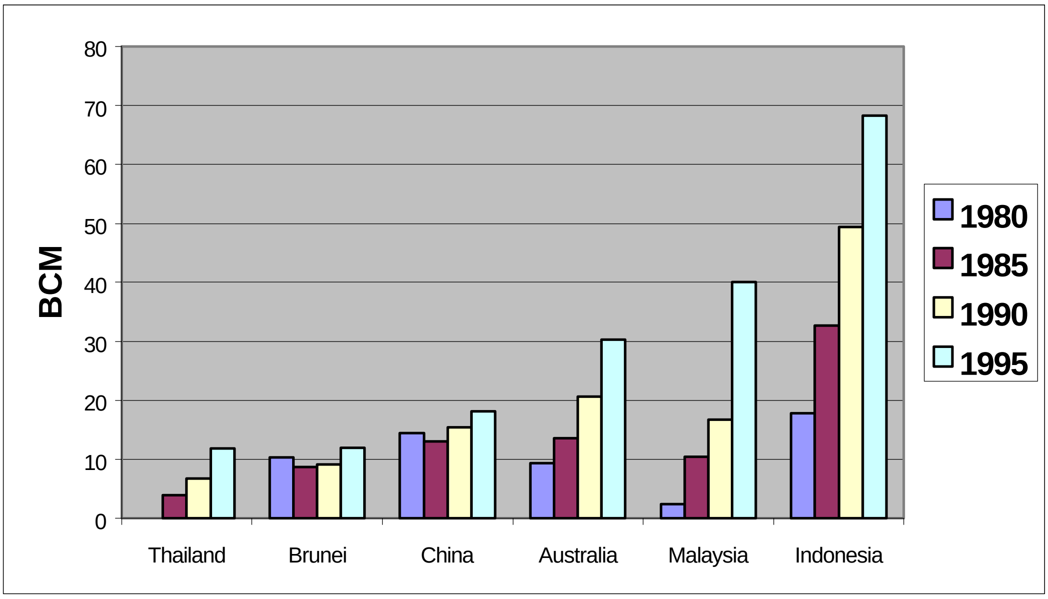
Figure 22 Natural gas consumption and production



Source: APERC, (1998c)

Many new LNG projects have also been proposed around the Pacific Rim and in the Middle East. These include Tangguh and Natuna in Indonesia, the Timor Sea in the Zone of Co-operation between Indonesia and Australia, the Northwest Shelf in Australia, Alaska's North Slope, and Canada's Pack-Rim project as well as projects in Qatar, Oman, Russia, Papua New Guinea and Viet Nam. Even before the economic downturn in Asia the capacity of these projects was greater than projected demand growth and not all of them would have been built. The current slowdown in energy demand has already resulted in delays in the development of several of these projects and has increased the likelihood that even fewer will actually be developed.

Figure 23 Southeast Asia and Australia natural gas production



Source: APERC, (1998c)

Australia, Brunei, Indonesia, and Malaysia will continue to be major players in supplying natural gas to East Asian markets. It is expected that these economies will be able to not only supply their growing domestic consumption but to maintain and possibly increase their exports of natural gas as well. The question that this and related studies are exploring is the extent to which pipeline natural gas can make inroads into the East Asian markets.

RUSSIAN PROJECTS

Russia has the largest reserves of natural gas in the world, however, the majority of the proven reserves are in the west, a considerable distance from Asian markets. Many proposals for gas pipelines have been put forward, but the Irkutsk and Sakha (Yakutsk) areas in East Siberia, and the Sakhalin area in the Russian Far East are the primary sources expected to supply pipeline gas into China, Korea, and Japan.

While exploration has occurred in each of these areas, more work is needed to verify the reserve estimates that have been made. Reserve estimates cover a considerable range, as shown in Table 35 below. Assuming that the reserves can be proven, the following observations can be made from this data.

- Current estimates of gas reserves in Irkutsk indicate they may not be sufficient to support a 56-inch pipeline, but considering geological characteristics, more exploration is likely to increase reserves (see also Figure 24). The likelihood that a pipeline of that size could be used increases significantly when Krasnoyarsk gas is included.

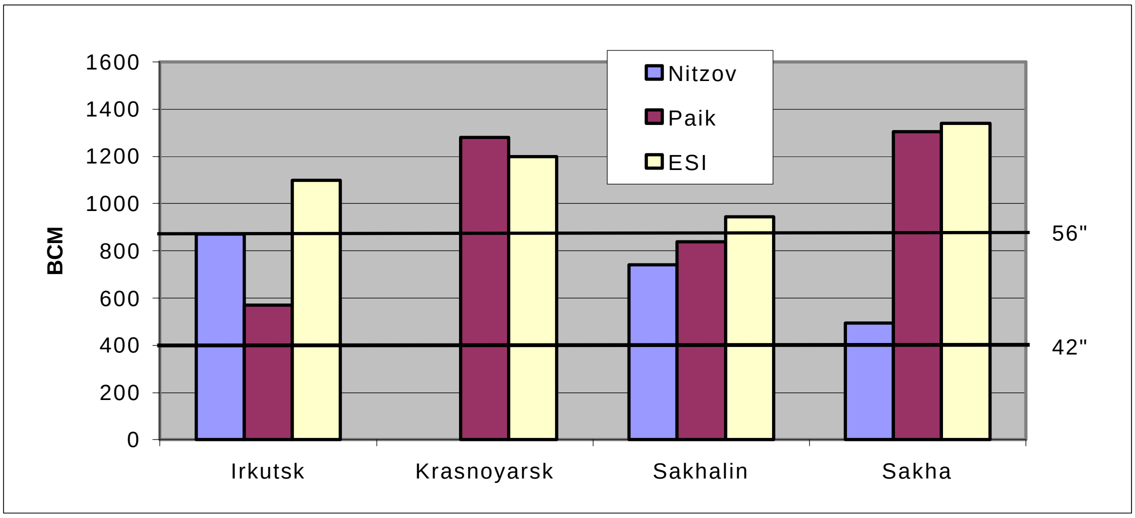
- Current estimates of gas reserves in Sakhalin indicate a base inadequate to support a 56-inch pipeline. Exploration is continuing, however, and could result in expansion of the reserve base.

- Sakha gas has been proposed to flow both Southeast to join Sakhalin gas and Southwest to join Irkutsk gas, but from these estimates, it appears that Sakha gas may be needed to support the Sakhalin reserves.

Table 35 Natural gas reserve estimates

Region	Source	C1 (BCM)	C2 (BCM)	Total (BCM)
Irkutsk	Nitzov, 1998	277	593	870
	Paik, 1995			570
	ESI, November 1998			1100
Krasnoyarsk	Paik, 1995			1280
	ESI, 1998			1200
Sakhalin	Nitzov, 1998	540	200	740
	Paik, 1995	615	223	838
	ESI, 1998			944
Sakha	Nitzov, 1998	420	75	495
	Paik, 1995	959	375	1334
	Paik, 1995,	1037	270	1307
	ESI, 1998			1340

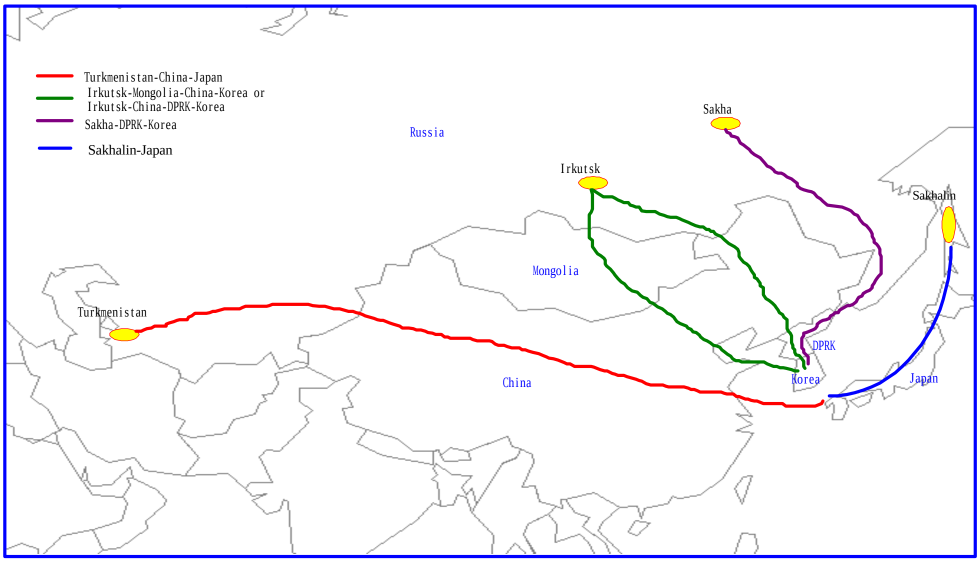
Figure 24 Russian natural gas reserve estimates



Note: The 42” and 56” lines indicate the reserves needed to support a 42- or 56-inch pipeline.
Sources: See Table 3-1.

Additional exploration and development of the reserve base is needed to verify and prove the extent of the Russian reserves. However, since these areas have not been extensively developed, it is very possible that this process will lead to the discovery of additional reserves and expansion of the reserve base. The issue of sufficient reserves cannot be overlooked and the reserve base will need to be verified before these projects go forward. This analysis has not imposed any constraints resulting from an inadequate reserve base. The best approach would be to base the analysis on demand scenarios. A low demand scenario, however, would be similar to a low reserve scenario, resulting in a smaller pipeline and lower throughput.

Figure 25 Various regional pipeline projects under consideration



SAKHALIN PROJECTS.

Sakhalin Island's North Eastern shelf was divided into 6 prospective hydrocarbon regions for exploration and development. The most advanced are the Sakhalin-1 and Sakhalin-2 projects. The Sakhalin-1 project develops the Odoptu-More, Chaivo and Akkutun-Daginskoye fields located between 7 and 50 km off the coast at water depths between 20 and 50 m. Total explored proven reserves (category A+B+C1 in the Russian classification) of gas, condensate and crude oil are officially estimated at 190 BCM, 11.5 Mt and 65 Mt respectively. The members of Sakhalin-1 project (Exxon, CODECO, SMNG and Rosneft) are more optimistic about the recoverable potential of these fields – they expect 425 BCM of natural gas, 33 Mt of condensate and 291 Mt of crude oil to be recovered over the project's 40-year life.

The first commercial crude oil was expected to be shipped from the Odoptu-More field in Autumn 1999 and start-up of oil production from Arkutun-Daginskoye field is planned for 2002-03. Gas may start to flow from Chaivo in 2005 and from Odoptu in 2011. A peak of oil and condensate production at about 24 Mt a year should be reached by 2011 while maximum gas output of between 17 and 20 BCM a year is expected between 2023 and 2029 – after extraction of oil and condensate.

Until recently, it was planned to liquefy produced gas at the LNG plant in Southern Sakhalin along with the gas from the Sakhalin-2 project. However, in late 1998 Exxon decided to revise the scheme within a new pipeline strategy that would provide for a gas pipeline crossing La Perouse (Soya) Strait, dividing southern Sakhalin and Hokkaido, and/or transiting northern Sakhalin and the mainland Khabarovsk territory before entering north-eastern China.

The Sakhalin-2 project has become the first Russian production sharing agreement (PSA). It develops the other two known hydrocarbon accumulations in the north-eastern Sakhalin offshore – the Lunskoye and Piltun Astokhskoye oil-gas-condensate fields located 13 km and 16 km off shore and at water depths of 50m and 30m respectively. Aggregate explored recoverable potential of these two fields is officially defined as 336 BCM of natural gas, 29 Mt of condensate and 65 Mt of crude oil. The project is being developed by Sakhalin Energy Investment Co (SEIC) - now consisting of Marathon, Shell, Mitsui and Mitsubishi - which are working on the assumption that over the project's life the two fields can yield around 100 Mt of crude oil, about 40 Mt of condensate and 370-400 BCM of natural gas.

The first crude oil was produced in July 1999, with gas and condensate following in 2005. Maximum gas output is estimated at 16.4 BCM/year to be reached around 2020, while crude + condensate production is expected to peak at 7.9 Mt/year around 2005. Natural gas is supposed to feed a 8.9 Mt/year LNG plant to be built at Prigorodnoye, near the southern port of Korsakov. The first oil was shipped in July 1999 from a single mooring buoy anchored next to the Piltun-Astokhskoye field, with later, bulk output to be loaded into crude-condensate pipelines linking the offshore fields to an ice-free export terminal and to the mainland refineries.

IRKUTSK PROJECT

The Kovykta field located west of the Baikal Lake in the Irkutsk region is being considered for utilization of both gas (mainly for export) and condensate (primarily for domestic use). The development is being carried out by RUSIA Petroleum which is controlled by two main shareholders – Sidanco (Siberian Far East Oil Co.) holding a 30 percent stake and Burovik East Siberia Holdings (a subsidiary of BP Amoco) with another 20 percent. Foreign participation in the project is also represented by South Korea's East Asia Gas Co (EAGC), a subsidiary of Hanbo Group, which holds a 7.5 percent stake.

Kovykta gas contains 91.7 percent methane, 6.1 percent methane homologues, 1.7 percent nitrogen, 0.25 percent helium on average. Gas reserves (as at the beginning of 1998) approved in RF State Balance are 870 BCM. Geological forecast estimations are much more – 2,500 BCM. The whole deposit area is underexplored yet so the prior target of "RUSIA Petroleum Co." is to complete a plan for geological exploration and achieve recoverable gas reserves of up to 1,500 BCM by the year 2003.

The Kovykta project envisages initial gas production of about 1.6 BCM a year, construction of a 720mm (28") gas pipeline to the Angarsk petrochemical plant as well as a condensate pipeline to the Magistral'naya railway station (on the Baikal-Amur main railroad), along with condensate-processing and loading facilities. As Kovykta gas output will gradually increase to 5-9 BCM in 2005 and between 20-25 BCM after 2010 – in order to supply the region's power stations and to feed a proposed 1,420-mm export pipeline to China, South Korea and possibly Japan, production of stripped condensate will grow proportionally – presumably from 0.3 Mt in 2000 to 0.5 Mt in 2005 and to 1.1-1.4 Mt/y after 2010. While stabilized condensate will be railed to Russian and interested foreign consumers by rail, massive natural gas supplies may be piped from Kovykta to (and further through) the Chinese port of Rizhao (on the Yellow Sea coast) either via Mongolia (for a total distance of 3,360 km) or by-passing Mongolia – eastward along the Trans-Siberian railway and southward after crossing the Russia-China border (4,540 km).

The export portion of the project, which is formally called the "Irkutsk Corridor Project" (ICP) has attracted serious interests from all the economies that would be involved in producing, transporting and consuming Kovykta natural gas. At the end of 1997, representatives of the Russian Ministry of Fuel and Energy, China National Petroleum Corporation (CNPC), Japan National Oil Corporation (JNOC), Korean Gas Corporation (KOGAS) and the Petroleum Authority of Mongolia gathered in Moscow to sign a multilateral memorandum of understanding which called for formation of an international consortium for conducting a joint feasibility study of the IPC and its various options involving supplementary gas resources of the neighbouring areas.

One issue waiting for resolution relates to the size of the proven reserve. The official, proven reserve is 870 BCM and the probable reserve goes beyond 1300 BCM. There have been disputes about these figures due to the difference in reserve categorization between Russia and the Western world. Therefore some effort needs to be made to reconcile the difference and confirm these figures.

Finally, in late February 1999, during a visit of the Chinese Premier Zhu Rongji to Moscow, an agreement for a bilateral feasibility study of the Kovykta project was signed at the top level as well as some other cooperative energy projects in oil and electric power.

The short distance between Sakha and Irkutsk gas deposits increases the probability of active participation of Sakha gas companies in a gas export project. Large capital investments are required for construction of a gas pipeline from the Kovyktinsky deposit to a number of Yakutian gas deposits, which are well investigated and are ready for industrial exploitation.

YAKUTSK PROJECT.

The region of the Republic of Sakha is endowed with abundant resources, and there are many gas fields scattered around. This project would involve the construction of a gas pipeline through the Far East regions. This would be a long distance pipeline, carrying a high volume of natural gas. However the project is attracting less attention as time goes by due to the existence of permafrost in the Sakha region and the wide dispersion of wells, which would increase the production and transportation costs substantially.

There was a proposal made to use natural gas from the Sakha region to back up the Irkustk project in case Irkutstk production turned out to be insufficient. According to Paik (1998), Sakhaneftegas has signed an important agreement with RUSIA Petroleum for joint development of the Kovyktinskoye in Irkutsk and Chayandiinskoye fields in Sakha.

WESTERN SIBERIA PROJECT

In August 1997, CNPC concluded a broad cooperation agreement with the Russian gas monopoly JSC “Gazprom”, which envisages massive supplies of northern, West Siberian gas to China and further to South Korea (and, possibly, to Japan) together with Kovykta and Sakha gas. A special route was proposed by Gazprom officials – from Tomsk in the south of West Siberia through the Altay mountain region to Urumchi, Jungaria, developing nearby Junggar, Tarim, Qaidam, Turpan-Hami basins and finally to Beijing and Yellow Sea Ports. In late 1998 Gazprom Chief Executive Rem Vyakhirev ambitiously proposed a 30 BCM annual delivery to China for a period of 30 years.

CHAPTER 4

ECONOMIC ANALYSIS OF NATURAL GAS PIPELINE PROJECTS

A SIMPLE MODEL OF NATURAL GAS TRANSPORTATION

Upstream natural gas development projects are attracting increasing attention in the APEC region. According to APERC's energy demand and supply outlook the gap between the APEC region's energy production and consumption is projected to widen despite the 1997 financial crisis. While APEC's total primary energy consumption is projected to grow 41 percent, energy production is expected to increase only 31 percent over the period 1995 – 2010. In order to fill this gap the region as a whole will need import fuels from other regions, as well as promote further regional exploration effort.

As explained in the previous chapters, natural gas will become the fastest growing primary energy source in the Northeast Asian region, and LNG is currently the only form in which it is widely traded. With newly discovered natural gas reserves in the Russian Far East and the Eastern Siberia, natural gas pipeline projects have become an attractive alternative to LNG.

However these upstream projects, by nature, involve various risks. Given the very large capital requirements, investment risks are large, lead-times will be very long, and political as well as economic instability will be important risk factors. This chapter will address various factors that affect the economic feasibility of projects, focusing on pipeline economics.

As there is no concrete project structure established for any potential project in the region, the model adopted for this study entails numerous hypothetical assumptions to cover uncertainties arising from the various risk factors

A simple model was chosen to demonstrate the impacts of various factors on the transportation costs of natural gas, using the model described in Kubota (1996) as a basis. Given assumptions on a number of such variables, such as distance, volume of natural gas, interest rate on loans, debt ratio[17], pipeline diameter, tax rates and so on, one can calculate either rate of return on investment with a fixed transport tariff or alternatively transport tariff with a fixed rate of return on investment. This model facilitates a number of exercises by changing values of these variables.

The model specifications assume that transportation tariff increases with distance, interest rates, pipeline diameter, and tax rates, while it decreases with volume of gas, discount rate and debt ratio. The analysis of pipeline project economic feasibility is limited in this study as more detailed information is not available because of its commercial nature and the model is too simple to accommodate project specific details including wages, right of the way, various taxes, and project financing methods, to name but a few. Also commercial level project evaluation is beyond the scope of this study.

Figure 26 Onshore pipeline transport costs

MAX. ANNUAL GAS THROUGHPUT	20	MMTON
PIPELINE LENGTH	10000	KM
PIPELINE DIAMETER	56	INCH
PIPELINE INVESTMENT	14000	MM$
COMPRESSOR STATION INVESTMENT	4121	MW
COMPRESSOR STATION INVESTMENT	5357	MM$

SUPPLY BUILD-UP		
1	25	%
2	50	%
3	75	%
4	100	%

CAPITAL EXPENDITURE OUTLAY SCHEDULE

	PIPELINE	COMP. STN.
1	10	10
2	25	25
3	30	30
4	20	20
5	10	10
6	5	5

	GAS SALES	TARIFF	REVENUE	CAPEX PIPELINE	COMP. STN.	OPEX PIPELINE	COMP. STN.	INTEREST PAYMENT	LOAN PAYMENT	LOAN	DERP.	SALVAGE	TAX	NET REVENUE	DIS. NET REVENUE
1	0.00	3.93	0.0	1400.0	535.7	0.0	0.0	174.2	0.0	1742.2	0.0	0.0	0.0	-367.8	-319.8
2	0.00	3.93	0.0	3500.0	1339.3	0.0	0.0	609.8	0.0	4355.4	0.0	0.0	0.0	-1093.7	-827.0
3	0.00	3.93	0.0	4200.0	1607.2	0.0	0.0	1132.4	0.0	5226.5	0.0	0.0	0.0	-1713.1	-1126.4
4	0.00	3.93	0.0	2800.0	1071.5	0.0	0.0	1480.8	0.0	3484.3	0.0	0.0	0.0	-1868.0	-1068.0
5	5.00	3.93	971.6	1400.0	535.7	35.0	127.3	1655.1	0.0	1742.2	0.0	0.0	0.0	-1039.3	-516.7
6	10.00	3.93	1943.2	700.0	267.9	70.0	254.6	1742.2	109.3	871.1	96.8	0.0	0.0	-232.9	-100.7
7	15.00	3.93	2914.7	0.0	0.0	105.0	381.8	1731.2	393.5	0.0	338.8	0.0	107.4	534.5	200.9
8	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	1691.9	760.8	0.0	629.1	0.0	274.9	1138.7	372.3
9	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	1615.8	1055.5	0.0	822.7	0.0	239.6	1148.9	326.6
10	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	1510.2	1270.4	0.0	919.5	0.0	242.2	1133.8	280.3
11	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	1383.2	1452.1	0.0	967.9	0.0	265.8	1103.9	237.3
12	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	1238.0	1597.3	0.0	967.9	0.0	309.4	1060.4	198.2
13	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	1078.3	1757.0	0.0	967.9	0.0	357.3	1012.4	164.6
14	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	902.6	1932.7	0.0	967.9	0.0	410.0	959.7	135.6
15	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	709.3	2126.0	0.0	967.9	0.0	468.0	901.8	110.8
16	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	496.7	2055.1	0.0	967.9	0.0	531.8	1121.5	119.8
17	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	291.2	1551.8	0.0	967.9	0.0	593.4	1768.7	164.4
18	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	136.0	856.3	0.0	967.9	0.0	640.0	2572.7	207.9
19	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	50.4	374.9	0.0	967.9	0.0	665.7	3114.1	218.8
20	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	12.9	128.9	0.0	967.9	0.0	676.9	3386.4	206.9
21	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	967.9	0.0	680.8	3524.3	187.2
22	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	967.9	0.0	680.8	3524.3	162.8
23	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	967.9	0.0	680.8	3524.3	141.6
24	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	967.9	0.0	680.8	3524.3	123.1
25	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	967.9	0.0	680.8	3524.3	107.1
26	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	871.1	0.0	709.8	3398.4	89.8
27	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	629.1	0.0	782.4	3083.9	70.8
28	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	338.8	0.0	869.5	2706.4	54.1
29	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	145.2	0.0	927.6	2454.8	42.6
30	20.00	3.93	3886.3	0.0	0.0	140.0	509.1	0.0	0.0	0.0	48.4	0.0	956.6	2328.9	35.2
												0.0			0.0000

DISCOUNT RATE	15	%
BREAK-EVEN	3.931	$/mmbtu
NPV AT 15%	0.0000	MM$

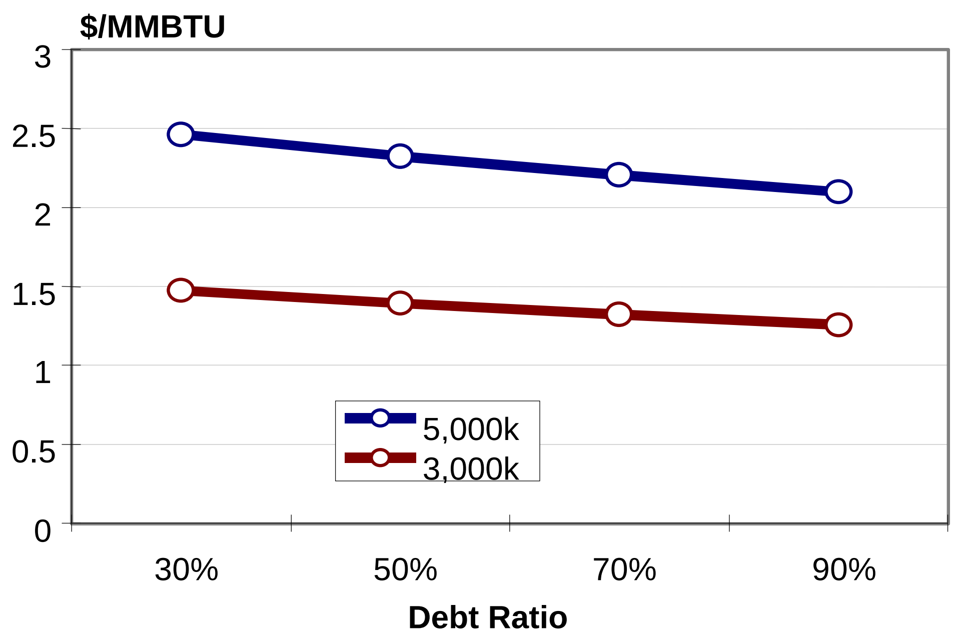
GRACE PERIOD	5	YEARS
REPAYMENT	10	YEARS
INTEREST RATE	10%	
DEBT RATIO	90%	
ANNUITY FACTOR	0.16275	
DEPRECIATION LIFE	20	YEARS
TAX RATE	30%	

FINANCING CONDITIONS AND TRANSPORTATION COSTS

Since natural gas development projects are capital intensive in the early stage of development, financing cost and the financial structures of concerned economies influence to a great extent the economic viability of natural gas development projects. The financing conditions have an important influence on transportation cost. The better the financing conditions are, the lower the unit transportation cost. Accordingly, in order to carry out natural gas development projects in an economically efficient manner, sophisticated financial management techniques have to be employed to minimize financial risks.

Usually natural gas development projects involve multiple economies and as a result, institutional factors affecting financing conditions must not be overlooked. Russia and China are experiencing the transition from a socialist economy to a market oriented one and there still exist socialistic elements in their economic structure. Thus foreign investors tend to be hesitant to make investment decisions on large-scale projects such as pipeline natural gas projects. What is needed before the start of these kinds of projects is an investment protection treaty among all the economies involved, i.e. producers, transit economies, importers, and other investor economies. Also sound natural gas trades call for stable tax and tariff systems and rational dispute settlement processes.

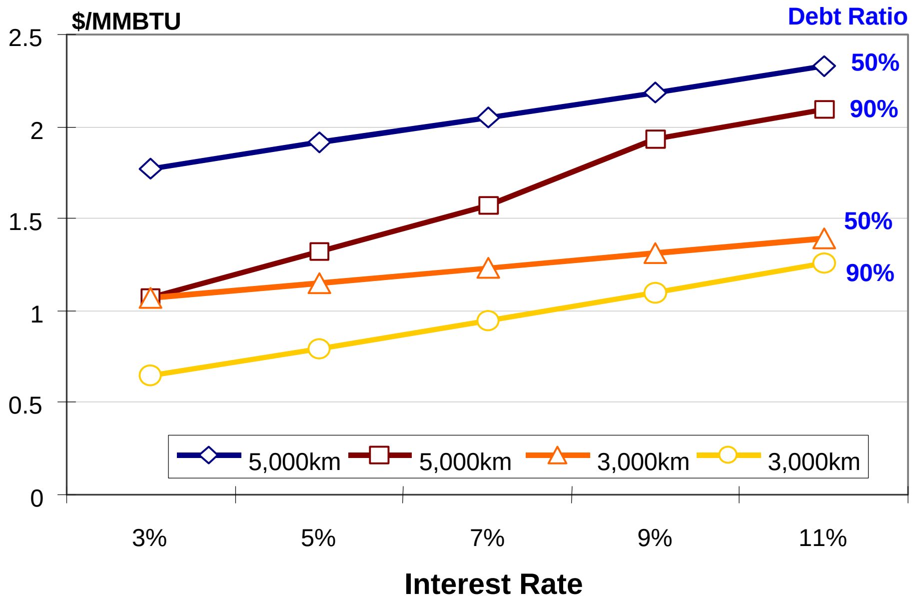
Figure 27 Debt ratio and transportation costs



NETBACK MARKET VALUE OF GAS

There are two approaches to assess the economic feasibility of pipeline projects. One is a cost-plus approach and the other is a netback approach. For the former, a benchmark price of natural gas is calculated as the sum of all the costs incurred along the fuel chain, encompassing the value of hydrocarbon at the well head, production cost, transportation cost, taxes and tariffs, and mark-ups. Then a comparison is made with the prices of other competing fuels, including natural gas price from other sources. However, as this approach requires detailed information with respect to costs along the pipeline, its use has been limited.

Figure 28 Interest rates and transportation costs



As the information on the value of gas at the wellhead is not readily known in advance, the netback approach is a practical alternative to the economic analysis of natural gas pipeline projects. The netback price is defined as "the delivered price of the cheapest alternative fuel to the customer adjusted for any differences in efficiency or in the cost of meeting environmental standards/limits" (IEA, 1998). Once the netback price is estimated, transportation and production costs are subtracted to determine the value of hydrocarbon at the field. The question then remains as to whether the estimated value is acceptable to sellers. Often, however, netback values are compared with natural gas prices of existing projects to provide a yardstick against which the economic feasibility of a particular project is weighed.

A simulation model[18] was used to demonstrate the relationship between netback values of natural gas and prices of other substitutable fuels. In most Asian economies coal and fuel oil are the two main fuels substitutable for natural gas for power generation. Table 36 and Table 37 contain the key assumptions for a preliminary computation made for two cases, one substituting natural gas for coal and the other for residual oil.

The efficiencies of power generation units were assumed to be 34 percent for coal, 36 percent for fuel oil and 45 percent for natural gas. Their calorific values are given as 6230 Kcal/Kg for coal, 9880 Kcal/l for fuel oil, and 9500 Kcal/m^3. For other variables in the model, the assumptions in Kubota (1996) were followed. The discount rate was set at 15 percent.

For the simulation, different values for costs of coal and fuel oils are assumed to demonstrate the relationship between prices of potential competing fuels and market penetrating price of natural gas. As seen in Figure 29 and Figure 30, competitive market prices of natural gas have a one-to-one relationship with other fuels. For example, if natural gas is to replace coal at 40 US$/tonne (1.48US$/Mmbtu) of coal, the natural gas price must be set at least equal to or below 3.1 US$/Mmbtu. By the same token, at a price of 3 US$/MMbtu for fuel oil, the natural gas price needs to be equal to or below 4.08US$/Mmbtu, to replace fuel oil in power generation. Whenever the actual price of gas is below the netback value, it is economical to switch from either coal or fuel oil to natural gas.

This outcome reflects differences in construction cost and efficiency of power generation units with specific design and input fuels. Current combined cycle and micro gas turbine technology innovations

18 The model was adopted and modified from Kubota (1996).

have enhanced the efficiency of natural gas fired power plants to a significant degree, allowing natural gas to penetrate even those markets where natural gas had no competitive edge.

Figure 29 Coal price and netback value of natural gas

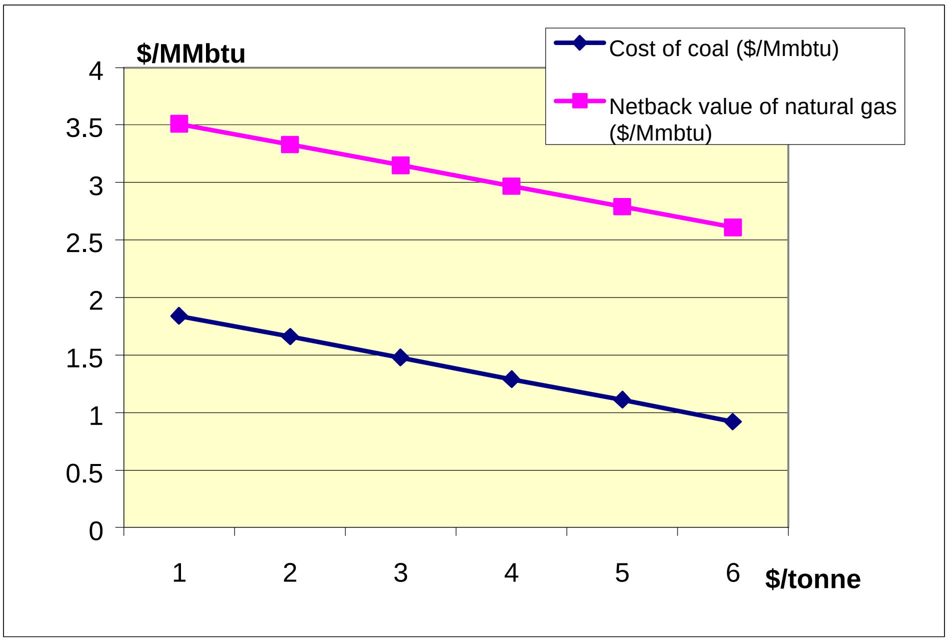


Figure 30 Residual oil price and netback value of natural gas

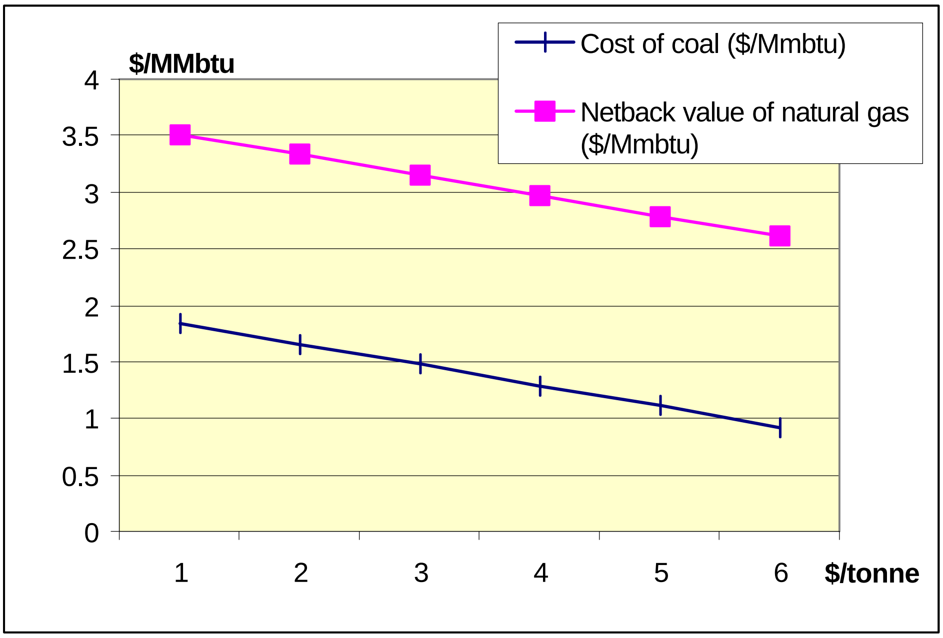


Table 36 Netback value assumptions for natural gas replacing coal in power generation

GAS VALUE IN POWER GENERATION													
	600 MW COAL PLANT							600 MW C.C. PLANT					
EFFICIENCY			34%				EFFICIENCY			45%			
RATED CAPACITY			600	MW			RATED CAPACITY			600	MW		
LOAD FACTOR			76%				LOAD FACTOR			76%			
UNIT INVESTMENT COST			1300	$/KW			UNIT INVESTMENT COST			650	$/KW		
OPEX			2.5%	OF INV. COST			OPEX			4.0%	OF INV. COST		
COST OF COAL			1.70	$/MMBTU	46.05	$/TON							
PLANT INST. PERIOD			5	YEARS			PLANT INST. PERIOD			3	YEARS		
	1TH		78.0	10%				1TH		117.0	30%		
	2ND		156.0	20%				2ND		175.5	45%		
	3RD		234.0	30%				3RD		97.5	25%		
	4TH		234.0	30%				4TH		0.0	0%		
	5TH		78.0	10%				5TH		0.0	0%		
			780.0	100%						390.0	100%		
ELECTRICITY HEAT		3412	BTU/KWH			406.0051							
1 GWH OF ELECTRICITY CONSUMES APPROXIMATELY:													
OIL FIRED CONVENTIONAL STEAM POWER PLANT ==					1521	BBL	9480	MMBTU					
COAL-FIRED POWER PLANT ==					406	TON	10037	MMBTU					
HATURAL GAS IN A COMBINED-CYCLE POWER PLANT ==					201	MCM	7584	MMBTU					
HEAT CONTENT		COAL	6230	KCAL/KG									
		RESID. OIl	9880	KCAL/L	62.14	KCAL/BBL							
		GAS	9500	KCAL/m^3									

Table 37 Netback value assumptions for natural gas replacing residual oil in power generation

GAS VALUE IN POWER													
					19.36247	$/per barrel							
600 MW RESID OIL PLANT								600 MW C.C. PLANT					
EFFICIENCY			36%				EFFICIENCY			55%			
RATED CAPACITY			600	MW			RATED CAPACITY			600	MW		
LOAD FACTOR			76%				LOAD FACTOR			76%			
UNIT INVESTMENT COST			1000	$/KW			UNIT INVESTMENT COST			650	$/KW		
OPEX			2.0%	OF INV. COST			OPEX			4.0%	OF INV. COST		
COST OF OIL			3.10	$/MMBTU									
PLANT INST. PERIOD			4	YEARS			PLANT INST. PERIOD			3	YEARS		
	1TH		90.0	15%				1TH		117.0	30%		
	2ND		210.0	35%				2ND		175.5	45%		
	3RD		180.0	30%				3RD		97.5	25%		
	4TH		120.0	20%				4TH		0.0	0%		
	5TH		0.0	0%				5TH		0.0	0%		
			600.0	100%						390.0	100%		
ELECTRICITY HEAT		3412	BTU/KWH										
1 GWH OF ELECTRICITY CONSUMES APPROXIMATELY:													
OIL FIRED CONVENTIONAL STEAM POWER PLANT ==					1521	BBL	9480	MMBTU					
COAL-FIRED POWER PLANT ==					406	TON	10037	MMBTU					
HATURAL GAS IN A COMBINED-CYCLE POWER PLANT ==					165	MCM	6205	MMBTU					

The current simulation is confined to the power generation sector, but the method could also be extended to other industries utilizing energy for heat applications.[19] These industries use the netback value of natural gas vis-à-vis other fuels as a key conversion criteria. However in practice the conversion does not take place automatically. Once the netback value criterion is met, the shift to natural gas is carried out only if a reduction in costs is also substantial. According to Van Groenendaal (1998), a company will convert to natural gas if the cost reduction is more than 7 percent of the total. If the reduction is between 2 to 7 percent, some will convert to natural gas, but others will not. With less than 2 percent cost reduction, no company will make the conversion. He also provided a formula for the penetration level estimation:

$$\textit{Penetration level} = \frac{a-2}{7-2} \times 100\ \% \qquad \textit{given: } 2 > a > 7$$

This equation could be used for the further detailed study of natural gas demand in the industry sector with heat application.

PIPELINE NATURAL GAS VERSUS LNG

Trans-boundary natural gas development projects require large-scale investment in infrastructure development. These projects have the potential to achieve economies of scale and in general, their profitability increases with volume of supply as long as there is secured demand. There are two types of trade depending on transportation modes and distance: PNG (pipeline natural gas) and LNG (liquefied natural gas) trades.

LNG projects include construction of liquefaction plants, tankers, and re-gasification plants. The economic feasibility of liquefaction and re-gasification plants is determined by annual production and peak supply. Transportation costs are mostly dependent on transportation distance.

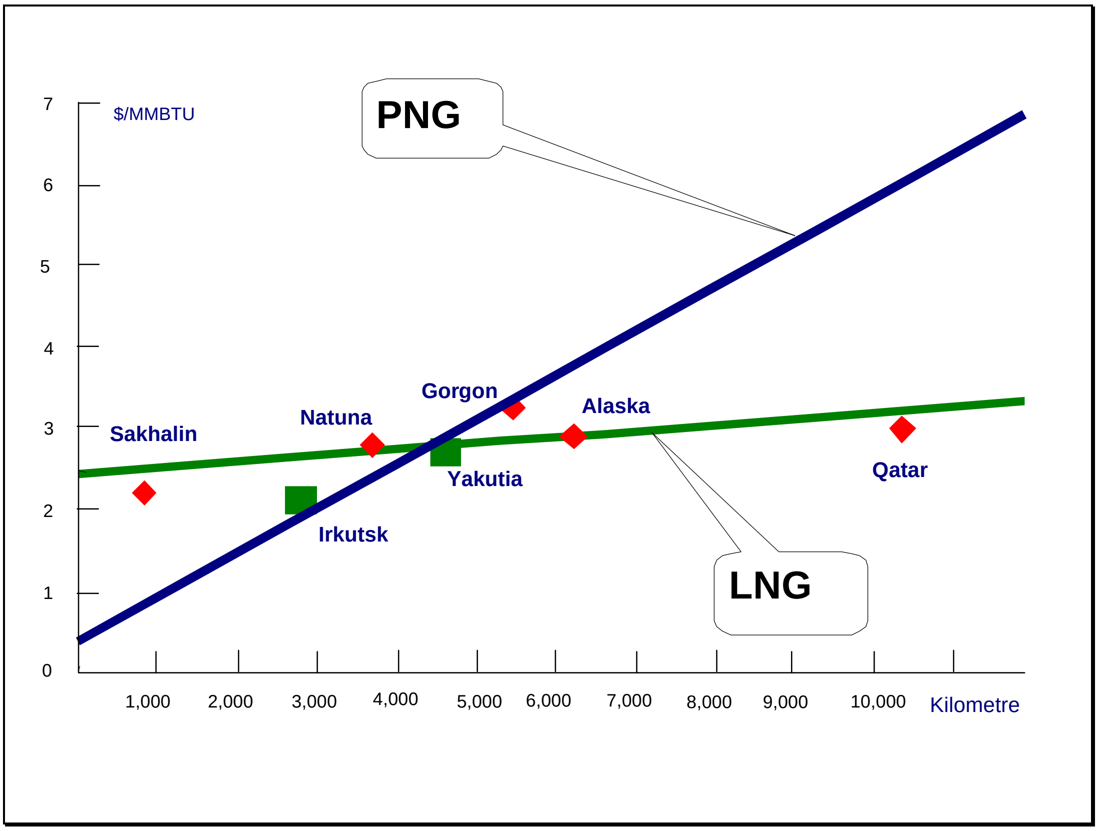
Unlike LNG projects, PNG projects need neither liquefaction plants nor re-gasification plants. The amount of capital investment for pipeline construction is the major determinant of a projects' economic feasibility. The required capital investment increases with pipeline distance and varies with route, geographical conditions and load factor.

Wellhead prices of natural gas also have a significant impact on the economic feasibility of pipeline natural gas projects. Assuming an identical wellhead price, the distance between the gas field and market can determine the type of trade. If the transportation distance is above some threshold level an LNG project would be the more feasible.

The threshold distance drawn from existing projects seems to be roughly 5,800km. Thus if the wellhead price of natural gas in the Russian Far East and Eastern Siberia is comparable to international prices, pipeline natural gas from those regions looks to be more economical than LNG in North East Asia (See Figure 26).

19 See for details Van Groenendaal (1998).

Figure 31 Transportation cost estimates by types of trade



In general wellhead natural gas prices are determined by the netback approach. Although the cost of natural gas production in Eastern Siberia may be higher than in the Middle East due to its remote location, PNG projects in the region seem economically feasible as production costs for regions other than the Middle East are comparable.

Considering distances and estimated production costs of proposed regional projects, (for example, the Irkutsk and Yakutsk projects), LNG does not appear to be a viable option. (Figure 31).

NATURAL GAS PRICE

Natural gas prices are determined in three major ways in the world depending on the region as well as the type of trade.

In Northeast Asia, where LNG is the dominant trade, natural gas prices are indexed to the price of crude oil. The current LNG price formula involves oil prices as a key determinant.

In the continental United States, gas prices are in general indexed to spot/futures prices where pipeline gas is the major source and markets are mature and flexible enough for extensive fuel competition.[20]

In Europe, both market conditions of natural gas and competing fuels affect natural gas prices. Whilst natural gas prices are more affected by prices of competing fuels in continental Europe, supply and demand changes are the major determinant of natural gas prices in U.K.

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[20] IEA/OECD, (1998).

Figure 32 Delivered price of natural gas in some APEC economies

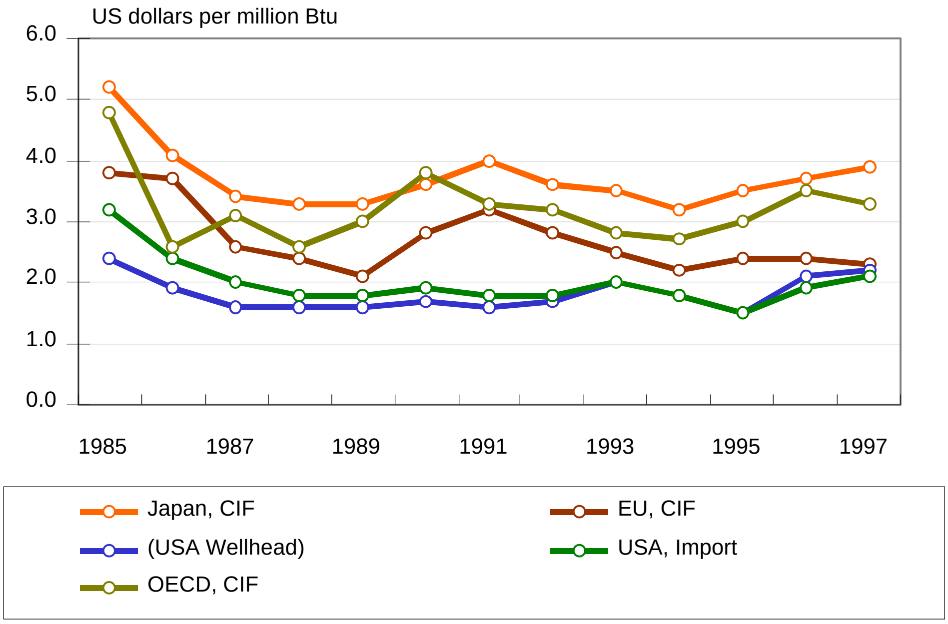


Figure 32 shows natural gas price trends in some APEC economies, in comparison with OECD and EU prices between 1985 and 1997. Even though the pricing formula is somewhat different across countries, all prices appear to exhibit the same trend over the period. The Japanese price was the highest for most of the period and domestically produced natural gas in the United States the lowest. As shown in Chapter 3, transportation distance could be the main determinant of the natural gas price.

TAX AND TARIFF

Governments' fiscal policies are an important factor in determining the economic viability of natural gas projects. The following tables show taxes and/or tariffs applicable to natural gas production and sales in Northeast Asian economies.

There are several tax laws governing tax rates: Profit Tax Law, Enterprise Income Tax Law, Individual Income Tax Law, and Value Added Tax. The tax system in Russia has changed significantly since 1990 and is still in constant revision. The following table was compiled from the Business Plan of the Irkutsk Project.

Table 38 Taxes in Russia

Taxes	Tax base	Tax rates
Excise duties for condensate	Sales revenue before VAT	US $17/tonne
Reproduction of material base	Sales revenue after VAT	10%
Royalty	Sales revenue	8%
Profit tax	Profit before tax	35%
Property tax	All taxable assets	2%
Militia tax	Business profit before tax	1.5%
VAT	Sales revenue after duties	20%
Tax on lubricant sales	Net lubricant sales revenue after VAT	25%
Road tax	Business profit after VAT	1.5%
Security tax	Salary fund	3%
City garbage tax	Salary fund	1%
Education tax	Salary fund	
Transport tax	Salary fund	
Pension fund	Salary fund	
Social insurance fund	Salary fund	
Employment fund	Salary fund	
Medical insurance fund	Salary fund	

Source: Compiled from Russia Petroleum, Business Plan of Kovyktinskoe Gas Condensate Field Development, 1997

The natural gas price is regulated in China by the Pricing Department of State Development Planning Commission (SDPC). It consists of the wellhead prices, gas processing costs, gas transportation charges and the Tax (VAT). (Table 39). All these cost components are regulated by the SDPC except the VAT.

Table 39 Value Added Tax in China as of March 2000

VAT on Natural Gas Sales	
Offshore Gas	5%
Onshore JV Gas	5%
Onshore Other Gas	13%

Note: Personal communication from official in the State Economic and Trade Commission (SETC), China.

The price level of natural gas in 1997 is shown in the following table.

Table 40 Natural gas price levels in China

Gas Prices Level in China (1997)	
Users	(Yuan/m^3)
Fertilizer Producers	0.51-0.65
Residential	0.63-1.1
Other Industries	1.0-2.0

Source: Quan, (1998)

In Korea, the wholesale price of natural gas comprises feedstock cost, supply cost and other government levied costs (Table 41). At the retail level, natural gas price consists of wholesale costs and regional supply cost plus value added tax at 10 percent of the total supply cost.

Table 41 Major components of the natural gas price in Korea

	Won/m^3
LNG import price (CIF)	136.34
Import handling Charge	Set by KOGAS
Import tariff	1.36 (1 percent of import price, CIF)
Special tax	32.31
Import levy	5.58 (set by MOCIE)
Loss	1.98 (0.9% of import price, CIF)
Safety management levy	3.90 (set by MOCIE)
VAT	10 percent of city gas rate.
KOGAS's Supply Price	214.83
End user price	273.21

Note: End user price is as of late 1997 in Seoul.

In Japan, tax on natural gas at the wholesale level is ¥720/tonne of LNG. Consumers are paying 5 percent tax on the delivered retail price of natural gas. (Table 42).

Table 42 Taxes in Japan

Items	Rate
Customs	¥720/tonne
Consumers Tax	5% on consumer's price

Source: IEA, (1999e)

CHAPTER 5

ISSUES

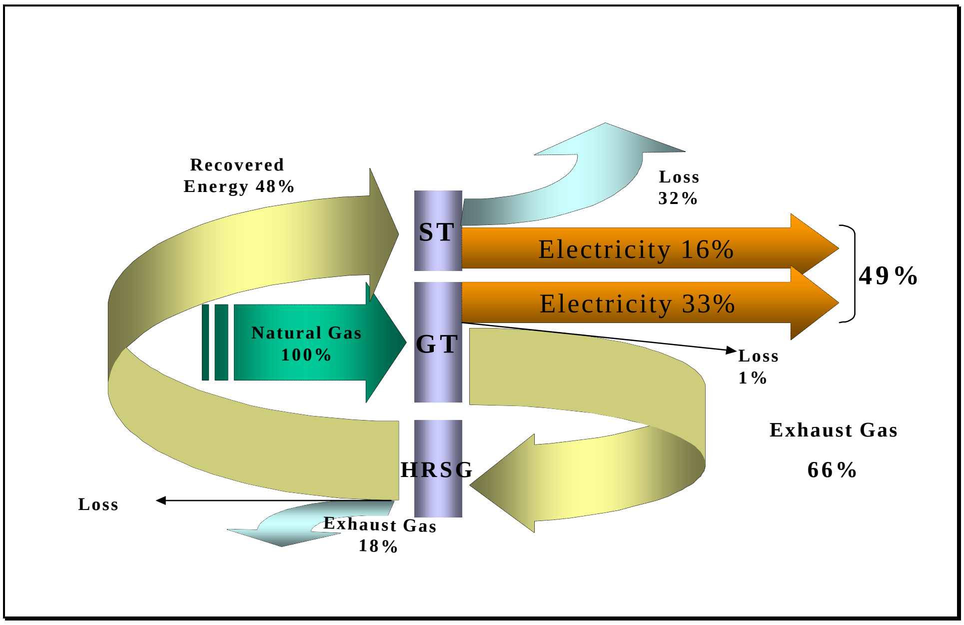
INTER-FUEL COMPETITION IN ELECTRICITY SECTOR

In current power generation fuel markets, natural gas has some distinct advantages over other thermal fuels, such as coal and fuel oil. These include higher thermal efficiency (with commercially available and proven generation technologies), shorter construction lead-time for plant (and lower capital cost), and relative environmental friendliness.

HIGHER EFFICIENCY AND SHORTER CONSTRUCTION LEAD-TIME

New combined cycle gas turbine technology has made natural gas a more efficient fuel than other thermal fuels for power generation. Two important areas of innovation are having a major impact on the power industry. The first is the development of the natural gas combined cycle turbine (CCGT). In comparison with the 30 – 40 percent efficiencies achieved by the old single cycle turbines installed 20 years ago, today's systems are running at 50 – 55 percent efficiency, and improving with time. The manufacturers of gas turbines are targeting at 60 percent efficiency and beyond.

Figure 33 Energy and heat flows in a typical modern combined cycle gas turbine



CCGT power plants have relatively low capital costs and rapid construction times, when compared with other traditional options. Plants can also be expanded in modular units. Fuel costs may in many places still be higher, but lower capital costs and rapid installation offset this disadvantage, especially for peaking plants that may run at low capacity factors. According to the Financial Times Asia Gas Report (August 1999), the investment cost of a gas combined cycle plant is currently US$500-700 per kW compared with US$1,100 per kW for a steam coal plant with smoke desulphurisation technology and US$1,500 kW for an IGCC plant.

Table 43 Past and projected power plant sales in the US (GW per annum)

Power Plant Technology	1987-1996	1997-2006
Gas Turbine	5.3	5.7
Gas Combined Cycle	14.7	24.6
Coal Steam Power	27.5	39.4
Total	47.5	69.7

Source: Hansen (1998)

According to Hansen (1998), fossil fuel based power plants in the US constituted 70 percent of all awarded contracts between 1987 and 1996. As shown in Table 43, from 1997 to 2006, the bulk of new electricity will be supplied by coal-based steam turbines, but with an increasing share of gas combined cycle plants. This is a clear indication that technology development in gas turbines, along with market deregulation, will increase the share of natural gas based power generation.

ENVIRONMENT

CLIMATE CHANGE (UNFCCC)

Various forecasts made by leading institutions in the region indicate that natural gas demand in the near future will grow rapidly and no one seems to disagree on the general pattern. However, some analysts see possibilities for even higher rate of growth than most anticipate. One important rationale for higher projected growth rates is the influence of the growing international public concern over global warming.

Increasing concern for the environment will boost the consumption of natural gas with time. The United Nation's Framework Convention on Climate Change (UNFCCC), adopted at the Rio Earth Summit in June 1992, has been ratified by more than 150 governments worldwide as of 1999. The UNFCCC was established to minimize the adverse effects of climate change on the present and future ecosystem (e.g. desertification and sea-level rise). The UNFCCC serves as the legal basis for the international development of responses to climate change, and aims to mitigate greenhouse gas emissions (GHG) particularly from the extensive use of fossil fuels.

The Convention and the Protocol require each party (Annex 1 economies have made binding commitments) to establish sustainable economic development plans. These commitments could have enormous potential impacts in the years to come. At the 3rd Conference of the Parties to the Climate Change Convention in Kyoto in 1997, all parties to the Convention developed an internationally agreed approach for GHG emissions reduction. The so-called Kyoto Protocol explicitly established targets and a timetable for advanced economies listed in Annex B of the Kyoto protocol. This approach was intended to make the implementation of GHG emissions reduction policies and measures in a legally binding manner.

One of the most effective measures to reduce greenhouse emissions is inter-fuel substitution between more carbon intensive fuels and less carbon intensive ones, as seen in Table 44. Depending on how details of the Kyoto Protocol - including rules, modalities, and guidelines - are developed in subsequent negotiations, it could play a major role in promoting growth of natural gas consumption in Northeast Asian economies.

Table 44 Environmental friendliness of natural gas emission factors [21]

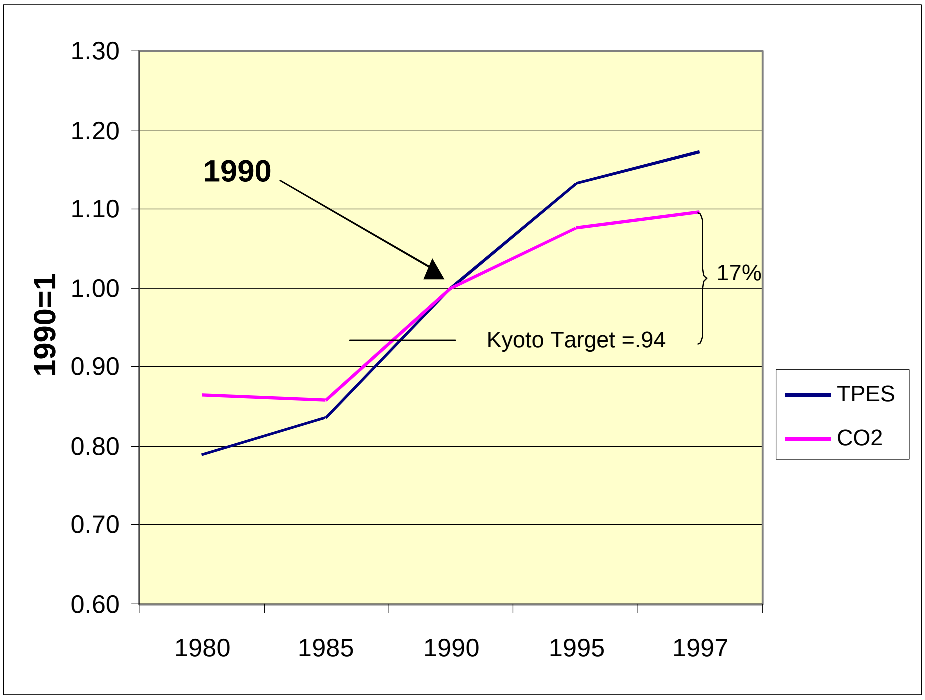
	Natural gas	Oil	Coal
SO_x (KG/TOE)	-	20.0	29.2
NO_x (KG/TOE)	2.3-4.3	8.2	11.5
CO_2 (KG/TOE)	13.8	19.9	24.1

Source: IEA

JAPAN

Since its adoption, the Kyoto Protocol has become an important factor in terms of energy policy formulation in Japan.[22] Despite targets set at Kyoto, energy demand (and the resulting CO_2 emissions) is growing strongly. As shown in the Figure 34, CO_2 emissions in 1997 exceeded the Kyoto target by 17 percent, while primary energy consumption grew about 17 percent between 1990 and 1997. Since CO_2 is the major greenhouse gas emitted by Japan, and the energy sector is the major contributor, Figure 34 indicates a challenging task for Japanese energy policy makers.

Figure 34 Energy demand and CO_2 emissions in Japan



Source: EDMC, (2000)

[21] The FCCC, aiming to stabilize the concentration of greenhouse gases - CO_2. NOx , SOx , and methane - in the global atmosphere is sure to boost the inter-fuel substitution toward natural gas as it has less greenhouse gas emissions than other fossil fuels.

[22] Japan agreed to reduce GHG emissions in 2010 to 6 percent below its 1990 level. See for details Kyoto Protocol to the Convention of Climate Change (1997), the Climate Change Secretariat, UNFCCC.

LOCAL ENVIRONMENT

Climate Change is a global issue, and understandably at a local level, support is limited. The atmosphere is a global commons. A farmer in the US may not have much concern about the GHG emissions of a steel manufacturer in Europe because the danger from these emissions to his crop cannot be seen, and causality is hard to prove. If the steel manufacturer is asked to pay for the GHG emissions to compensate for alleged crop losses in the US, he will be reluctant to do so for the same reason.

In contrast, local air pollution has begun to have a significant bearing on the formation of energy and environmental policies in many economies in the APEC region. Notably, Northeast Asian Economies have begun to pay more attention to improvements in environmental quality in cities and townships. As a result governments in the region are reinforcing environment standards and encouraging a change in the energy mix toward more environment friendly resources.

Beijing's Clean Air Programmes

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

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

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

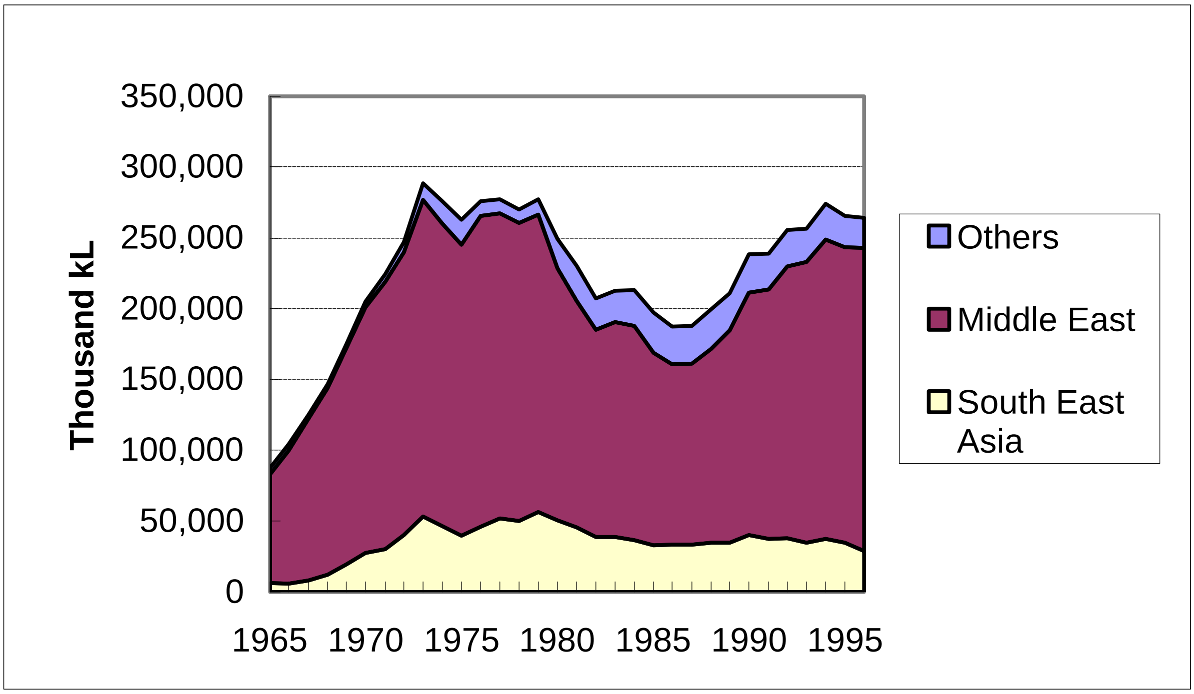
After authorization by SDPC's pricing Department, the Beijing municipality is able to increase the SO_2 emission fee by 2.5 to 6 times from September 1999. This is also part of efforts to promote fuel switching from coal to natural gas in the city.

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

ENERGY SECURITY

East Asia is highly dependent on oil imports. In 1995, oil import dependence was about 73 percent for the region and nearly 100 percent for the economies other than China. This has resulted in various efforts to reduce the region's dependence on oil. Japan, for example, the second largest oil consumer in the world, has been struggling to diversify its oil import sources away from the Middle East. However, dependence on Middle East oil remained at more than 80 percent in 1995 (Figure 35).

Figure 35 Japan imports of crude oil by source

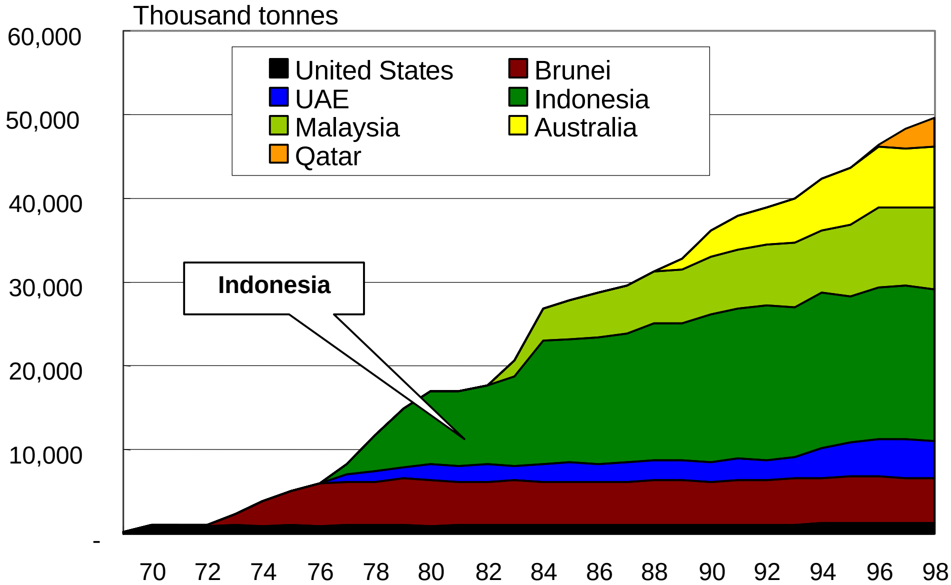


Source: EDMC, (1998)

Natural gas is one alternative to oil, and unlike oil, a large amount of natural gas is produced inside the APEC region. APEC is much less dependent on outside sources of natural gas. From East Asia's perspective, the sources of supply are geographically much closer. Figure 36 shows the sources of LNG supply for Japan.

However, Northeast Asia remains dependent on LNG that must be delivered in special tankers and requires re-gasification facilities. Natural gas via pipeline is seen as an additional means to diversify supply sources.

Figure 36 Japan imports of LNG by source



Source: EDMC, (1999)

Japan and Korea also have extensive nuclear programmes as a means of energy supply diversification, but expectations are that the planned additions will not be fully realised. This may result in increased demand for gas if utilities elect to go with gas-fired combined cycle units to meet the growing electricity demand.

DOMESTIC PIPELINE GRID

Table 25 shows a comparison of projected generation costs for CCGT power plants for selected APEC member economies. Japan incurs the highest generation costs, followed by Korea, Canada and the USA. Japanese costs are highest for each category – capital investment, O&M costs and fuel costs. Expensive land and high safety requirements, including earthquake measures, raise the costs of investment substantially. Also, other additional regulatory costs are incurred, such as compliance with strict environmental regulations. The fuel cost share is the highest contributor to overall generation costs. As Japan is endowed with few natural gas resources, it imports LNG from South East Asia and the Middle East. The reason costs are higher than, for example, Korea (which also imports LNG) is the higher proportion of long-term take-or-pay contracts, which ensure greater security of supply, but result in overall higher fuel prices than might be achieved with spot market procurement.

Table 45 shows estimated natural gas transmission line construction costs in Japan, calculated by the Mitsubishi Research Institute. The estimates are based on a trunk line with a total length is 5,267km. The unit cost of construction is estimated to be approximately 800 million Yen/km, a unit cots which is 4~6 times as high as for Europe or the USA. The main reason for the high construction costs is two fold: high safety requirements - including measures to allow for frequent earthquakes, and difficulty in obtaining access across land already used for other purposes.

Table 45 Estimated pipeline construction costs in Japan

	Length (km)	Diameter (inches)	Construction Cost (million Yen)	Unit Construction Cost (million Yen/km)
Pipeline Cost	5,267	30~40	4,201,210	798
(Submarine cost)	(150)			
Other Cost	-	-	24,000	-
TOTAL	-	-	4,225,210	-

Note: *Other costs include O&M costs in operation centres
**Yen =1999 price
Source: Mitsubishi Research Institute (2000)

As seen in Chapter 2, compared with Europe and the USA, the natural gas pipeline transmission network is not well developed in Japan[23]. Also, natural gas utilisation is limited to power generation plants located close to LNG terminals or city gas supply in the vicinity of the terminals. The development of a nationwide transmission trunk line, combined with reticulation networks would obviously enhance natural gas utilisation greatly. Such a development could also create gas (LNG) to gas (pipeline natural gas) competition, provided that it incorporates LNG terminal and third party access.

DEREGULATION AND PRIVATIZATION

Once markets are deregulated, competition in the power sector puts strong pressure on generators to lower overall costs, including those associated with fuel inputs. Although the choice of input fuel for existing facilities may be constrained, there still exists inter-fuel substitution potential. For example a conversion from fuel oil to natural gas is possible through the replacement of burner tips without a substantial amount of investment. Another possibility for lowering costs and increasing competitiveness is to increase the capacity factor (utilization rate) of a particular plant or plants, usually those that are already cost effective in a deregulated market.

Deregulated electricity markets, with the emphasis on cost structures, will tend to encourage investment in power generation plants that are least cost over the capital depreciation period. In most cases this will favour the lowest cost fuels, usually coal, but also hydro where this is readily available, and gas because new CCGT plants have relatively low capital costs, even if operating costs are somewhat higher. Private investors in fully competitive markets would be unlikely to invest in nuclear, because of the very high capital cost, and requirement for relatively large plant size. With respect to both hydro and gas plants, the future will likely see a large increase in smaller sized plants placed much closer to demand centres (encouraging the trend towards more highly distributed generation).

Below are some graphs showing generation fuel mix trends over a period of around twenty years for a number of selected APEC economies. In almost all cases, these trends precede significant reform in each of the economies chosen, but some observations about the likely effect of reform can be made. For example Figure 37 shows that in the United States coal has shown steady and relatively strong growth with respect to all other fuels. Nuclear has grown over this time period, but one would expect this trend to reverse over the next twenty-year period. (see EIA, 1998) Little new investment has occurred in nuclear since the early 1980s, and as old plants reach retirement, the share of nuclear generation will decline. Although gas generation shows only modest growth, this fuel should become increasingly

[23] The total length of the natural gas trunk line in Japan is 1,200km, while in the U.K it reached 4,700km as of 1997.

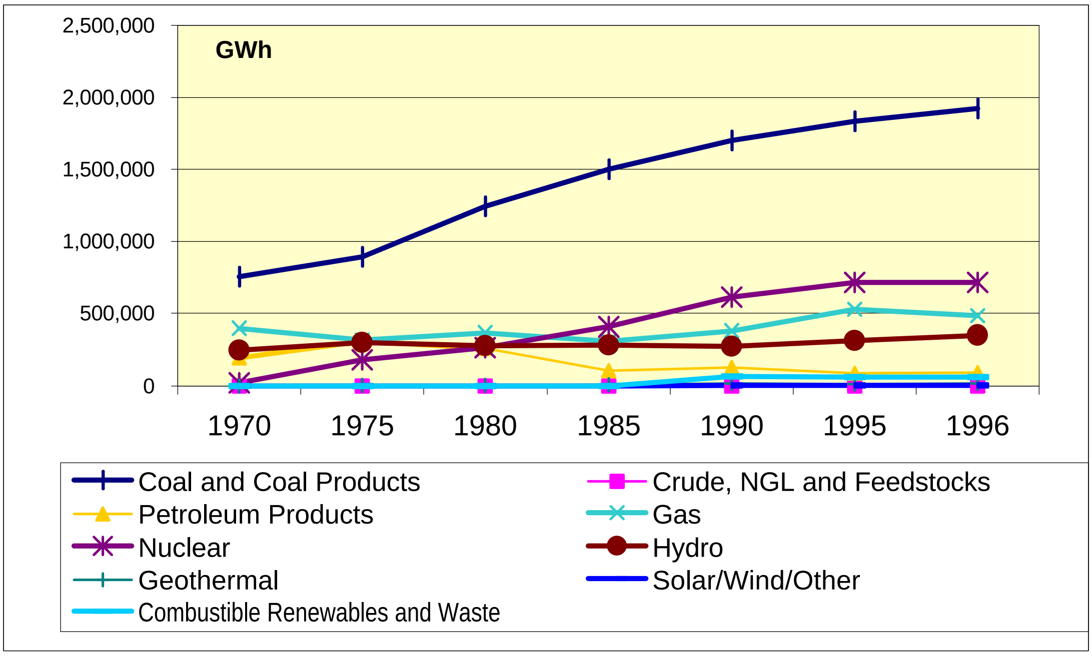
important over the next twenty years as gas market deregulation and growing investment in CCGT plants takes effect.

Canada has undergone very little reform, and has abundant supplies of hydro, so investment in this form of generation may continue into the foreseeable future, with gas and coal generation possibly becoming more important once some reform measures begin to take effect. Another economy with abundant hydro capacity, but with a long history of electricity sector reform, is Chile. Hydro has shown very strong growth, as has coal generation. With the construction of links to Argentinean gas in 1997 and 1999, gas generation capacity has grown substantially, and should continue to do so. In New Zealand, abundant hydro capacity has ensured strong investment over the last twenty years. What is important however, is that the investment since the early 1980s has switched from large-scale hydro to small scale plants closer to demand centres. Very recently, gas generation has undergone dramatic growth, and this trend could continue into the near future (while gas supplies last).

In Australia, coal is the cheapest fuel, and growth in coal consumption for power generation has undergone strong growth as seen in Figure 39. Although no new capacity has been added so far post-reform, brown coal plants in Victoria have been operating at higher capacity factors, displacing some more expensive fuels, such as gas.

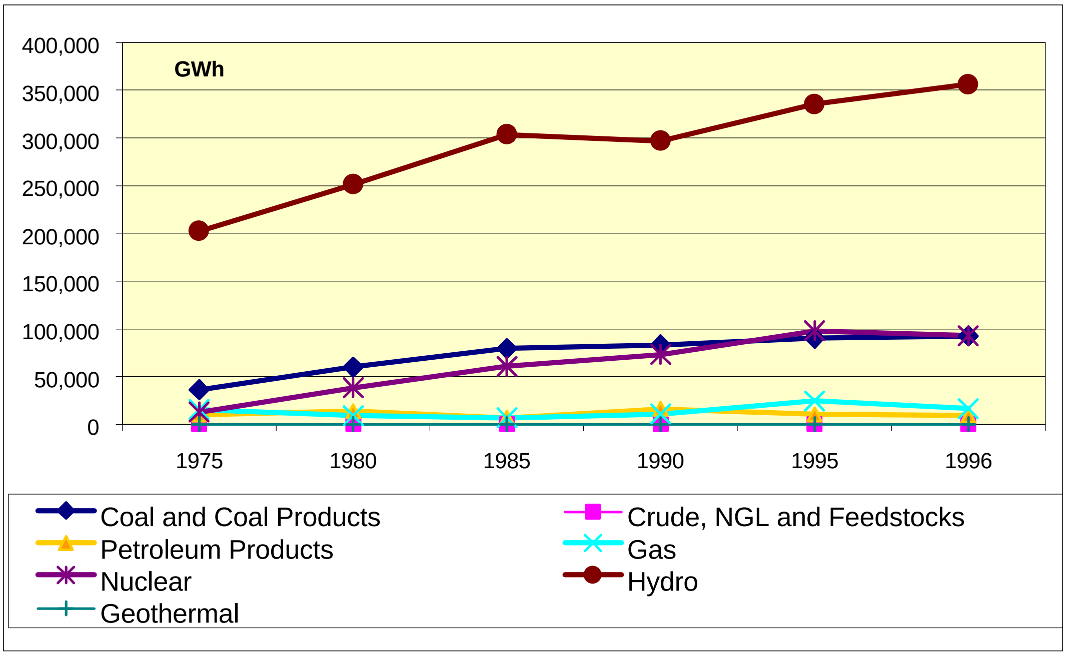
It has been argued that, faced with the uncertainties created by deregulation - such as loss of protected service areas and/or long-term contracts - electricity generation investment is likely to face higher financing costs. (Hansen 1998). Such an effect would discourage investment in power plants with high capital costs and long-term payback periods. This is probably a correct analysis, at least in the early post-reform stage, but the development of lower cost CCGT plants, and the recent world-wide expansion in gas supply, has tended to mitigate this effect.

Figure 37 Power generation fuel mix trends in the US



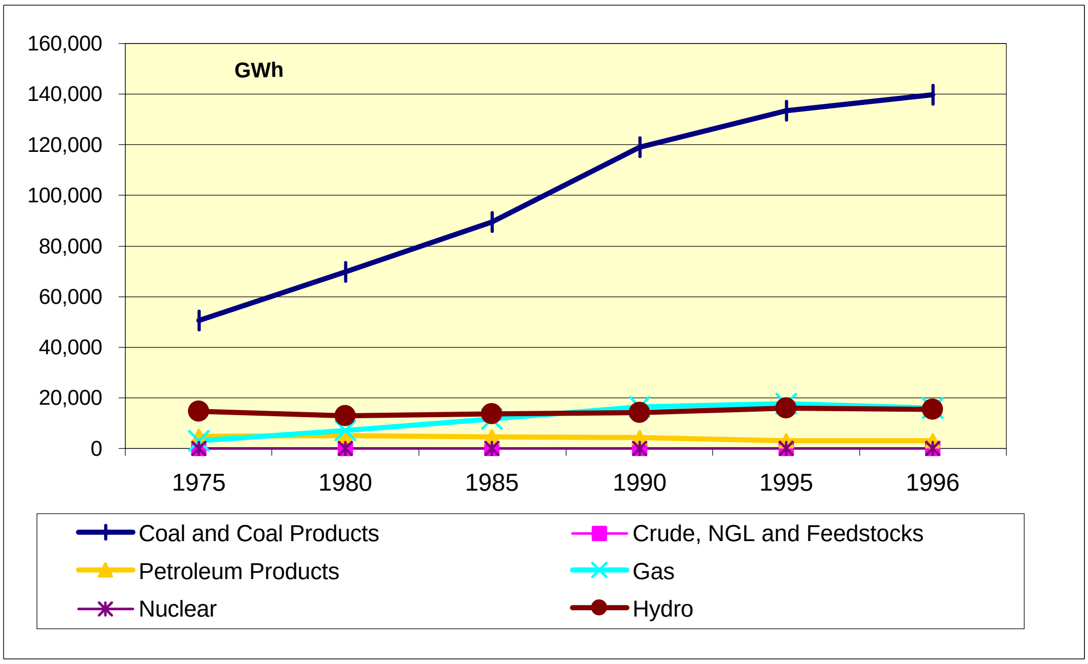
Source: IEA, (1998b)

Figure 38 Power generation fuel mix trends in Canada



Source: IEA, (1998b)

Figure 39 Power generation fuel mix trends in Australia



Source: IEA, (1996)

The incentive among electricity generators to find more economic fuels can result in undesirable consequences such as environmental degradation. However the course of deregulation impact can be altered by way of government policies and supporting enabling legislation. In the United States, for example, the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992 helped increase natural gas consumption in the electricity sector.

To facilitate effective competition amongst fuels, natural gas markets should be deregulated in parallel with power markets. One way to facilitate competition in natural gas markets is to guarantee open access to gas networks, in order to discourage monopolistic practices by pipeline owners. In addition where electricity competes with other types of fuel for a given market, such as household heating, the justification for deregulation in these fuel industries is greatly enhanced. Should natural gas compete against electricity, natural gas transportation costs become an increasingly important factor as their share in terms of total supply cost is large and electricity transmission costs are anticipated to fall steadily with technology development. (Ellig & Kalt, 1996).

An interesting question is what effect electricity sector deregulation will have on commitment by investors to long-term gas contracts. This is most significant with respect to bringing new (particularly offshore) gas fields to production.[24] With fragmentation of ownership in the power sector, many players may have to be brought to the table to ensure sufficient markets exist for investment in new gas supplies. From the financer's point of view, this may increase the rate of interest required on loans

INSTITUTIONAL ARRANGEMENT

RUSSIAN PRODUCTION SHARING AGREEMENTS

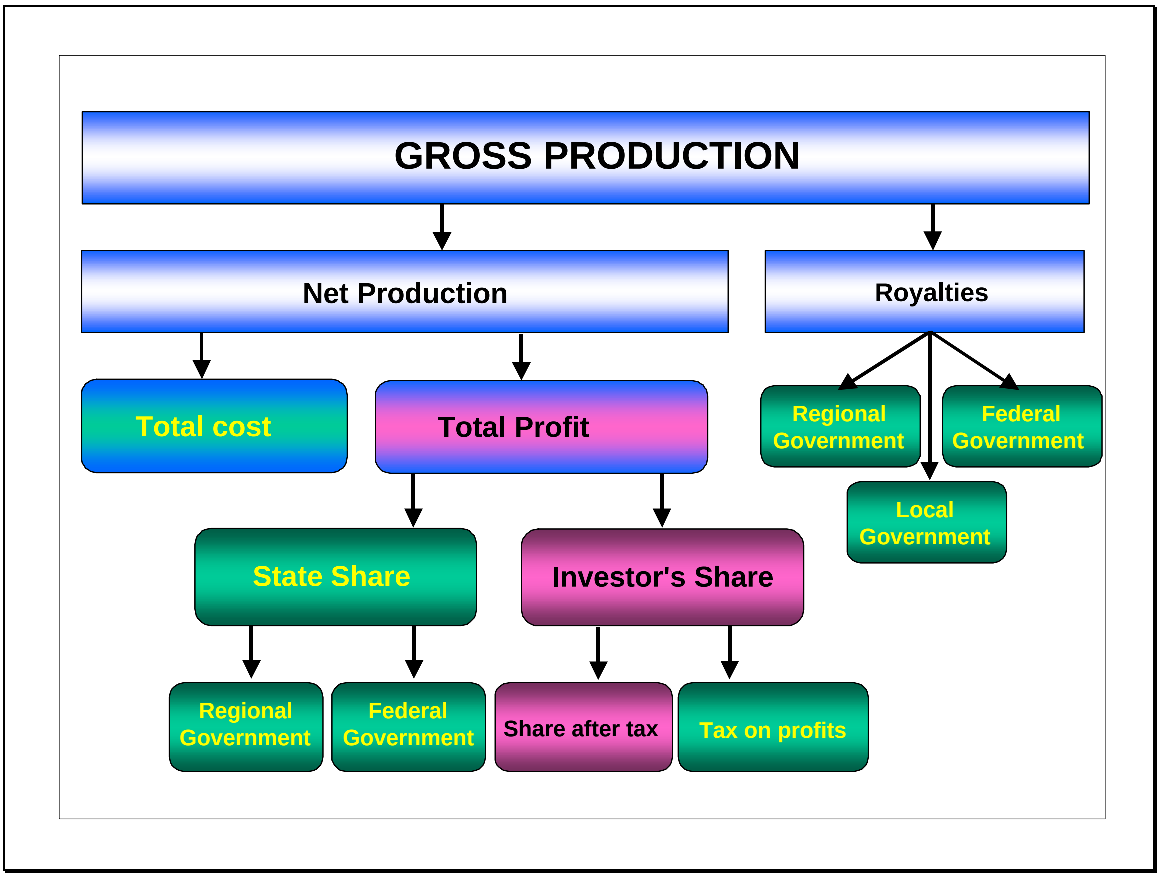
Slow progress with respect to Russian production sharing agreements has been regarded as one of the most serious stumbling blocks to pipeline projects in the region. Product Sharing Agreements (PSAs) are mandated by legislation, and designed to provide foreign investors with an autonomous regime under which they are not subject to the Law on Underground Resources, and are exempted from paying certain taxes. Under the "self-contained" regime, investors negotiate with the Russian government over the shares in production profit that may be paid to the state in monetary form.

The main purpose of Russian PSAs is to protect the rights of investors in an environment where legislative frameworks are inadequate, and hence to encourage foreign capital. It is anticipated that foreign investment will resolve the difficulties the former Soviet states have in natural resource development where they are short of capital as well as technology to explore natural resources. Therefore PSAs have been applied in many developing economies for the purpose of encouraging foreign investment under relatively secured conditions.

Figure 40 shows profit flows under PSAs in Russia. First, royalties are charged to investors for using underground natural resources. Secondly, a net production royalty is divided into two parts: profit and cost. Thirdly, the PSA determines the share of the investor and the government out of total profits. Finally a profit tax is imposed on the investor's share of profit that goes to the government. In other words, the government gets a royalty, a share of profit, and a profit tax.

24 For example, the take-or-pay is still a "must" in Liquified Natural Gas (LNG) contracts.

Figure 40 The flow of profit under a PSA



However, the Russian 1995 PSA Laws was not able to confer autonomy on foreign investors because of conflicts with other laws, such as the 1992 Law on Underground Resources. This resulted in delays in the negotiation and signing of several projects.

The government had encountered many difficulties attempting to enact the PSA law in 1995 due to objections raised within the Duma (the Lower Chamber of the Russian Parliament), based on fears of reducing revenue as well as nationalistic feelings. As a result of attempts to settle objections, the 1995 PSA law is in conflict with other laws, and contains compromise provisions. The main problem was whether PSAs would be treated as civil-law contracts under special, self-contained PSA Law regimes, or would be subject to the general Law on Underground Resources. Under this legislation, the Russian state would be free to restrict, interfere with and even terminate investors' PSA rights essentially at will (Hines and Nikiforov, 1999). The 1995 PSA Law, Article 2.2 states that "the terms of use of underground resources established in an agreement must not contradict the requirements of the Law on Underground Resources".

In January 1999, the Russian parliament amended the 1995 PSA law in order to resolve the conflicts. The driving forces behind the amendment were as follows: (1) after the financial crisis in August 1998, 10 Russian oil companies requested tax exemption with respect to PSA projects; and (2) the government and parliament recognised the importance of facilitating further foreign investment (Komori, 1999).

Table 46 Existing and proposed projects under PSA conditions

Project	Site	Russian Companies	Foreign Investors
Agreements signed before adoption of 1996 PSA Law			
Sakhalin-1	Sakhalin	SakhalinmorNG	Exxon, SODECO
Sakhalin-2	Sakhalin		Marathon, Mitsui, Shell, Mitsubishi
Kaharyaga	Nenet	Lukoil	Total, Norsk Hydro
Agreements signed after adoption of PSA Law - List Law No.1 1997			
Prirazlomnoye	Pechora Sea	Rosshelf	
Samotlorskoye	Tyumen	NizhnevartovskNG Chernogrneft	Haliburton
Krasnoleninskoye	Khanty-Mansiysk	Kondpetroleum Yugraneft KrasnoleninskNG Khanty-ManskyskNG	
Romaskhinskoye	Tatarstan	Tatneft	
Northern Sakhalin	Sakhalin	SakhalinmorNG	
Agreements signed after adoption of PSA law - List Law No.2 1999			
Salym	Khanty-Mansiysk	Evihon	RD/Shell
Usinskoye	Komi	Komineft	TB(Switzerland
Block-15	Komi	Parmaneft	
Udmurt	Udmurtia		Samson Oil & Gas (USA)
Yurubchenskoye	Evenk Auto.Dis	East Siberian Oil	
Uvat	Khanty-Mansiysk	Uvatneft	
Fedorovskoye	Khanty-Mansiysk	Surgutneftegaz	
Luginskoye	Tomsk	Tomskneft	
Kirinsky	Sakhalin		

Source: Russian Petroleum Investor, February 1999

Table 47 shows the problems with the 1995 PSA law with respect to other laws and how they were fixed. Even though the new PSA Law broadly states that the terms of resource use must accord with the legislation of the Russian Federation, the new law favours the dominance of the PSA Law over other legislation. Also, as shown in Table 47 the new law exempts the application of the Law on Underground Resources, rather it will be based upon the new PSA Law with respect to assignment and termination of rights, extension of the contract/license term, and field conservation/liquidation measures.

Table 47 PSA precedence over contracts

The Problems	The Fixes
PSA Law/Contract Dominance	
PSA Law Art 2.2 had provided: "The Terms of use of underground resources established in an agreement must not contradict the requirements of the Law on Underground Resource"; and the URL itself contained many burdensome resource use rules, without express exception being made for PSAs.	PSA Law Art 2.2 now says that the terms of resource use "must accord with the legislation of the Russian Federation." This broad statement, while not ideal, should be tolerable to investors in light of the overall amendments introduced. A new final paragraph of the Law on UR Art. 1 will now say: "The particulars of resource-use relations on production sharing terms shall be determined by the PSA Law" Additional new language will support the dominance of a PSA over the associated resource-use license: Law on UR Art.7, para 1 is amended to provide that mineral plots may be on the basis for obtaining resource-use right; and new Law on UR Art. 11, para. 2 states that a PSA development license "evidences the defines all required terms of in accordance with PSA Law and the Law on UR"
Termination of Rights	
PSA Law Art 2.2 had provided that "Termination of obligations regarding the use of licenses shall be determined in judical proceedings on the basis of this federal law and the Law on UR". And the Law on UR, at Art. 20, provided (and still provides) several extra contractual bases for state authorities to attempt termination of a PSA investor's rights, for example "breach of material terms of the license", "systematic violation of resource-use rules", or threat to life or health of people living near the project area.	First, the relevant sentence of the PSA Law Art. 2.2 has been amended to read: "The right to use an underground resource plot may be restricted, suspended, or terminated pursuant to the terms of an agreement concluded in accordance with Russian Federation Law." Second, a new paragraph has been added to the Law on UR Art. 20 to the same effect: "In the case of use of underground resources in accordance with a PSA, the right to use underground resources may be terminated, suspended or restricted on terms and in the manner provided in sad agreement." A similar companion paragraph has been added to the Law on UR Art.21, indicating the inapplicability to PSAs of the general Law on UR based procedures for termination of rights by the state.
Extension of Contract/License Term	
Law on UR Art. 10, fourth para., had appeared to limit extension of use rights to the same length time period as the maximum initial term (20 years for development stage).	New final sentence of Law on UR Act 10 provides: "The manner of extending the term of resource use on the basis of a PSA shall be determined by such agreement." This should mean that PSA (and associated license) extensions are governed by existing PSA Law Art. 5.2, which provides that, at the investors' initiative and, per details reflected in each agreement, assuming the agreement obligations have been carried out over the initial term, an extension "sufficient for completion of economically viable extraction of the mineral resource and assurance of rational use and protection of the subsoil is in order."
Assignment of Rights	
Lingering uncertainty as to whether PSA-related assignments would need to satisfy the limiting conditions of the Law on UR Art 17 –namely, that an assignment of resource-base rights can only be made in the event of certain specified types of corporate reorganisation of the original resource user (license holder).	A new final paragraph of this Law on UR article has introduced favourable clarifications: "Assignment of the right to use resources granted on the basis of a PSA, and registering a valid license shall be carried out in accordance with the Law PSA." This amendment, together with existing PSA Law Art. 17.2 proving that a proposed transfer of PSA rights and obligations "shall be accompanied by appropriate registration of the license…within 30 days of signature of the assignment agreement, "should suffice to establish that only the PSA Law conditions need be satisfied for assignment of contract as well as associated license rights in the PSA context".
Conservation/Liquidation	
Law on UR Art. 26 has provided general requirements – with associated rules, burdens and potential open-ended expense, applicable to all resource license- holders, presumably including PSA investors, with regard to conservation/liquidation of fields and project installations upon termination of the license period.	Law on UR Art. 26 now prides that such conservation and liquidation measures for projects under PSA development "be carried out on account of the money in the liquidation fund established by the investor, the size, formation and utilisation of which shall be defined "in the PSA in accordance with Russian law"

Source: Hines and Nikiforov, 'The Shape of Things to Come', *Russian Petroleum Investor*, February 1999

TAX

Originally the 1995 PSA law contained a provision that investors will be exempted from tax payment other than tax on profit. Instead the PSA substitutes all the tax payments as well as levies required by the Russian Federation. Because of uncertainty about fluctuating tax rates, an attempt was made to simplify matters to encourage more foreign investment. However, the validity of this provision was not ensured because the relevant tax law did not correspond to the law on PSAs. In accordance with the amendment of the PSA Law in 1999, the relevant tax law was amended, bringing about a significant effect on the PSA regime validity. The relevant amended tax laws include:

- The Law on the Basic Principles of the Tax System;
- The Law on Road Funds;
- The Law on Property Taxes;
- The Law on Excise Taxes;
- The Law on Value-Added Tax;
- The Law on Customs.

RESOLUTION OF DISPUTE

One of the problems that arises when the Law on Underground Resources or the Continental Shelf Law is applied to PSAs concerns the resolution of disputes. The Law on Underground Resources and the Continental Shelf Law state that disputes concerning PSAs must be considered by Russian state courts (Court of general jurisdiction) or State of Arbitration courts (Russian state commercial courts) (Hines and Nikiforov, 1999). In other words, the Law on Underground Resources and the Continental Shelf Law do not allow PSA-related disputes to be submitted to international arbitration. However there may be a danger that presumably distorts the resolution when disputes in the use of mineral resources are within the jurisdiction of Russian Court, favouring its own side[25].

The amended 1999 UR Law ensures the autonomy of PSA regimes, providing that the disputes will be under the jurisdiction of the Russian Court or international arbitration tribunals where parties are agreed.

PROBLEMS REGARDING NEW PROJECTS

The changes in the PSA law introduce the following new restrictions:

- 30 percent ceiling on the portion of Russia's energy reserves eligible for development on PSA terms,
- Non requirement of parliament approval [26] for PSAs on fields with oil reserves of up to 25 million tonnes and/or gas up to 250 billion m^3,

Specific minimum quotas requirements in equipment/materials procurement[27], and employment of Russian workers[28]

25 Also, there is a conflict between the Law on Underground Resources/Continental Shelf Law and the Foreign Investment Law (FIL) with respect to dispute resolution. The FIL states that in specific cases, disputes between foreign investors and state authorities (including PSAs) must be reviewed by Russian courts, or where the parties agree, by arbitration tribunals, including international arbitration tribunals.

26 On the other hand, fields with oil reserves of more than 25 million tons and/or gas with more than 250 billion m^3 still require parliament's approval under the Field List Law.

27 70% of total material/equipment procurement should be oriented to Russian companies.

28 80% of total employees should be Russians.

AN EXAMPLE: THE SAKHALIN-2 TAX ISSUE

In late 1999, the Sakhalin Duma (the Lower Chamber of the Sakhalin Parliament) considered the endorsement of a draft law to levy regional taxes on Sakhalin Energy, the operator of the Sakhalin-2 project production-sharing agreement. Under the PSA that went into effect on May 19 1996, Sakhalin Energy had been granted an exemption from any taxes except for the profit tax and payment for the use of land and other natural resources, for the entire period of the agreement's validity. (*Russian Petroleum Investor*, February 2000). According to the Sakhalin Tax Inspector, it is estimated that Sakhalin Energy was exempted from almost US$1 billion throughout the period of the PSA's validity.

The main purpose of PSAs, as it was indicated earlier, is to protect investment rights from inadequate legislative frameworks and to encourage foreign investment in a relatively stable environment. Therefore the mere possibility that a regional government might consider revising the relevant tax laws will significantly impact on the confidence investors have in Russian oil and gas exploration projects.

On the other hand, the Sakhalin regional government is encountering problems associated with value-added tax (VAT) accrued to projects under PSAs. The 1996 Law on PSAs and individual PSA contracts provides that the Federal Government should reimburse all VAT paid by foreign investors to suppliers and contractors until commercial oil/natural gas production commences. Also they stipulate that if commercially produced oil/natural gas is exported, the VAT imposed on the exported product should be reimbursed. In reality, the impoverished Federal budget has failed to reimburse any VAT for three years. Consequently, the debt owed by the Federal Government to the investors amounts to US$70 million and keeps increasing (Russian Petroleum Investor, February 2000).

As the Sakhalin PSA contract stipulates that the VAT debt can be met by investors' withholding royalty payments, Sakhalin Energy - which started commercial production in July 1999 - is not making any royalty payments, subsequently bringing about revenue losses to the Sakhalin regional government.

In the summer of 1999, the Sakhalin Duma proposed that the Federal Government reimburse the VAT to the investors. However, the Federal Parliament has failed to include these expenses in the budget.

TECHNOLOGY DEVELOPMENT

Technology development has provided a powerful impetus to the expansion of natural gas consumption. Cost reductions in production and transportation of natural gas help make gas more competitive, while efficiency improvements in natural gas using technologies such as combined cycle and micro gas turbines, and natural gas vehicles, make it more affordable to consumers. This section attempts to give a brief overview of some of the major technologies that could have significant impact on the future consumption of natural gas.

PRODUCTION AND TRANSPORTATION

There have been technology developments in the production and transportation of natural gas in particular in the areas of liquefaction plant construction, long distance pipeline construction, and distribution systems installation, which contribute to substantial savings in investment capital. One good example (FT Asia Gas Report, 1999) is the Atlantic LNG Trinidad Plant, which has been constructed with 30% cost savings for the stakeholders in the project.

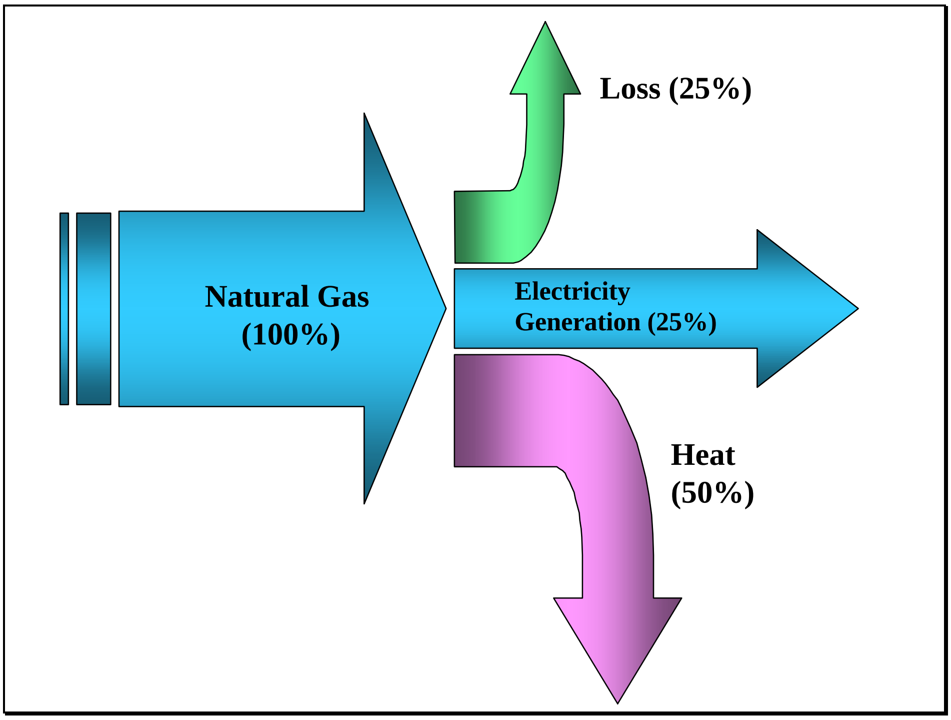
MICRO GAS TURBINE

The emergence of the CCGT has been discussed, and the way in which this development has dramatically altered economies of scale in power generation. Other developments that will reinforce a trend towards smaller scale, distributed power systems are advances in fuel cell technology, wind turbines, and other smaller scale, clean power sources.

Another influence on the possible location of future power supplies is the lowering of power transmission losses with technology development. In this case, gas network vs electricity network competition may be intensified. Recent deregulation in natural gas markets in the United States, which helped remove all price controls on the wellhead sales[29] of natural gas as of January 1 1993, set the stage for competition among alternative substitutes.

The emergence of new technologies such as the micro gas turbine and fuel cell could be an important factor in changing the future configuration of both electricity and natural sectors. Micro gas turbines exist in the range 28kW-70kW, sufficient to power approximately 10-30 households[30]. The energy balance (input and output) for a micro gas turbine (Figure 41), results in 25% of the total natural gas input being available for electricity generation, while 50% is transformed into heat. When the heat is used for hot water supply, the overall thermal efficiency could reach 60%-75% currently.

Figure 41 Energy balance for a micro gas turbine



In addition, small-scale power plants with micro gas turbine generation capacities between 1kW-1MW of electricity are generating high power revenues with improved profitability, flexibility, and reliability according to a recent article by Vuorinen (2000).

29 The Natural Gas Wellhead Decontrol Act of 1989 revoked the Supreme Court Phillips Decision in 1954, which imposed of wellhead price control on the interstate sales of natural gas.

30 This is the approximate number calculated by taking the average scale used in Japanese residential sector.

NATURAL GAS VEHICLES

In most big cities in the APEC region, transportation has been the major source of air pollution. Conventional combustion engines fuelled by diesel and gasoline emit fumes containing NO_X, CO, CO_2, and SO_x. This is, in particular, true of developing economies where motor vehicle technology is lagging behind and environment standards, and their enforcement, are not tough enough.

In this regard, natural gas vehicles using either LNG or compressed natural gas (CNG) offer an attractive alternative with the significant potential reduction of harmful gases. In some developed economies such as the United States, Canada, and Japan, natural gas vehicles are beginning to replace old combustion engine vehicles slowly but steadily. In 1998 following the Kyoto conference on Climate Change, the Japan Gas Association following the government's greenhouse mitigation plan has announced an ambitious plan to introduce this type of vehicle on the streets of major cities in Japan.

Table 48 Projection of number of natural gas motor vehicles in Japan

		Number of cars in 2010		Annual natural gas consumption			
			Total	Fuel efficiency (km/m3)	Mileage (km/year per car)	Fuel consump-tion (m3/year per car)	Total fuel consumption (m3/year)
CNG	Passenger Car	93,825*	187,650	10.0	10,726	1,074	100,766,902
		93,825*		8.1		1,319	123,741,756
	Light Truck	64,150	128,300	17.7	7,116	402	25,790,475
		64,150		15.0		474	30,432,760
	Small Truck	92,790	185,580	15.1	13,703	905	84,020,299
		92,790		12.8		1,068	99,143,953
	Truck	211,130	422,260	9.3	31,125	3,356	708,524,308
		211,130		7.9		3,960	836,058,683
	Bus	14,100	28,200	2.1	27,548	13,042	183,896,790
		14,100		1.8		15,304	215,792,667
	Special car	12,605	25,210	2.9	17,310	5,915	74,560,057
		12,605		2.5		6,980	87,980,867
LNG	Large Truck	22,500	22,500	2.6	150,000	57,781	1,300,077,042
		0		(2.2)		(68,182)	0
	Bus	500	500	2.6	130,000	50,077	25,038,521
		0		(2.2)		(59,091)	0
Subtotal (efficiency improvement)		511,600					2,502,674,393
Subtotal (without efficiency improvement)		486,600					1,393,150,686
TOTAL		1,000,200					3,895,825,078

Note: *Upper row shows the number with efficiency improvement, while lower row shows the number without efficiency improvement.

**Special car includes garbage truck.

Source: Japan Gas Association

About a million natural gas motor vehicles will be put on the road consuming 3.9 BCM a year, which is equivalent to roughly 2.8 million LNG tonne.

GAS-TO-LIQUID TECHNOLOGY

Recently Chevron of the US and Sasoil of South Africa entered into a joint venture to harness gas-to-liquid technology (FT Asia Gas Report, 1999). Even though Gas-to-Liquid (GTL) technology has been around for decades, full-scale development has been restricted due mainly to unfavourable economics. Some studies suggest that capital costs can be reduced to such an extent that commercial production is economically feasible at oil prices below US$20/Bbl. With high oil prices, it is more likely that GTL technologies could be commercialised and disseminated.

GTL products have two major advantages in terms of regional market penetration. One is ease of transportation and the other is its growing demand due to high quality (Holmes, 1998). As abundant gas reserves are located at rather remote areas in East Siberia and the Russian Far East, GTL processes could provide an alternative to regional natural gas development.

More importantly, GTL could offer high quality middle distillates, demand for which has been growing rapidly in the region. With these merits, GTL could offer an alternative to other gas type fuels such as LNG or PNG should its capital cost be significantly reduced and world oil prices remain high enough to ensure economically justifiable prices for GTL products.

OTHER FACTORS AFFECTING THE ECONOMIC VIABILITY OF PNG PROJECTS

There are numerous factors that affect the economic viability of pipeline natural gas projects. They could be classified as institutional, economic, and environmental. Institutional factors include investment protection treaties, assurance of fiscal stability (tax and tariff), dispute settlement mechanism for resolving trans-boundary jurisdiction, guarantee of repatriation of profits and earnings and harmonization of technical standards. These factors are prerequisites that need to be established and put in place before any investment is made. Unfortunately, however, much work needs to be done to change institutional factors favorable for PNG projects in the region. One example is the Russian Production Sharing Agreement, which is still not operational because of slow progress in legislation in the Russian Parliament. Since the declaration of the December 1995's presidential decree little progress has been made.

Market factors are also important and questions such as financing and whether PNG can compete with LNG in terms of price need to be addressed. Answers to these questions involve large uncertainties. Key elements are the market penetration price of delivered gas and interest rates for borrowed capital. These questions are interwoven with other market and non-market conditions. Nevertheless project participants should be able to foresee their future course of action within a reasonable margin of error, and build and maintain confidence in them, but the present volatile economic conditions keep them from making sound forecasts.

One could increase natural gas consumption for the purpose of improving local environmental quality. As pointed out in the previous section, Climate Change negotiation may boost natural gas consumption for the global environment. Yet substitution of natural gas for other fossil fuels is beneficial, not only to the global environment but also to local environment as fossil fuel burning entails emissions of greenhouse gases and other local pollutants such as SO_x. In China and Korea, fast urbanization and the following population concentration have created serious local air pollution problems and both governments are seeking ways to improve air quality. The Korean government, for example, has tightened environmental regulations, restricting heavy fuel oil consumption in 6 major cities. It is also expected that coal would be replaced by natural gas in large cities of China including Beijing and Shanghai.

CHAPTER 6

CONCLUSIONS

Natural gas use has been increasing for the last twenty years at a faster rate than any other primary energy sources in the APEC region as well as in the world. Until now, rising per capita income combined with its ease of use, has been the key factor in its expansion. In future, technology development and the environment will play major roles in promoting natural gas consumption. On the one hand, technology development, for example, CCGT and Micro Gas Turbines will pave the way for further penetration into the power generation sector. Environmental concern on the other hand, borne out by global climate change and exacerbating local pollution is likely to increase pressure on energy policymakers to promote natural gas consumption in most economies in the region.

In the Northeast Asian region, natural gas consumption is well below that for other parts of the world, as seen by its current share of total primary energy. Other regions such as Americas and Europe use natural gas far more extensively, with its share of total primary energy above 25 percent on average, well above the 5 percent in Northeast Asia as of 1995. Despite the low share of natural gas, its absolute volume of consumption has increased substantially as total energy consumption has grown.

The current trend of high growth in natural gas consumption in Northeast Asian economies will not be reversed in the near future. According to the APERC demand and supply outlook, the Northeast Asian economies are projected to require 131.2 million LNG tonne equivalent by 2010, equal to 5.6 percent growth per annum. This estimate is conservative because several would-be drivers for natural gas demand had not been factored into the projection, such as climate change, technology innovation, and construction of trans-boundary natural gas pipelines.

Natural gas has been traded in this region in the form of LNG only. The existing long-term LNG contracts would cover the major portion of natural gas supply for both Korea and Japan in future, but there still exists a significant demand and supply gap to be filled by either new LNG contracts or natural gas pipeline projects. It amounts to about 29 million LNG tonne equivalent in 2010. In addition, China's state petroleum agencies and companies targeted natural gas imports of roughly 22 million LNG tonne per year by 2010. Adding up those unsecured amounts of natural gas over the three economies, namely China, Japan and Korea, the required supply from other regions is about 50 million tonnes. This amount exceeds the total natural gas consumption in Japan in 1998.

For the last two decades LNG has been imported into Japan and Korea - for the most part from the Southeast Asian economies, such as Indonesia and Malaysia. However recent contracts indicate an increase in LNG imports from the Middle East in future. Oman and Qatar have made headway into both Korean and Japanese markets. The share of Middle East natural gas in Korea will go as high as 61 percent by 2010 from 5 percent in 1997 on the basis of current contracts. The increase in dependence on the Middle East for natural gas supplies may become a serious concern for Korea, as there is already a heavy reliance on the Middle East for oil.

The aggregation of scattered natural gas resources in the Russian Far East region, East Siberia and in China has enough potential to supply regional economies. The supply potential of the Russian region amounts to 12,018 BCM and that of China, 65 – 130 BCM by 2010. The issue is that natural gas reserves are located far from major cities, where most of natural gas would be consumed. The distance between gas fields and consumption centres is one of the most important variables determining the economic feasibility of pipeline projects as the size of investment in pipeline construction in general comprises the major portion of total project investment cost.

Apart from transportation related factors, the feasibility of pipeline projects depends on many other economic variables, among which the market prices of competing fuels, interest rates, build-up period, and taxes and tariffs are most relevant. No single variable can be overlooked because each has potential detrimental impacts on the integrity of natural gas pipeline projects as the simulation demonstrates. Thus the role of each economy or project stakeholder is to ensure that all these variables are kept within manageable ranges that could secure private foreign investment. From an investors' perspective, project development plans need to be carefully thought through prior to making investment commitments.

With a view to meeting the fast growing demand, Northeast Asian economies have considered several natural gas pipeline projects - the Sakhalin, Irkutsk, and Yakutsk projects being the major ones. These projects are at different stages of development: projects in Sakhalin are under way, while the other two projects are in a very early stage of negotiation. No concrete development plans for Irkutsk and Yakutsk projects are anywhere near being finalized and uncertainties exist, hampering their economic viability. The features regarded as undermining the economics of these projects include instability in Russia, lack of a nationwide pipeline network in Japan, the uncertain future of electricity and gas sector deregulation in Korea, and an immature market coupled with cheap coal in China. They can be translated into risks, raising project investment costs.

To cope with the above-mentioned, expected difficulties, inter-governmental efforts must be put forward with a view to establishing institutional measures for stabilization of tax systems, foreign investment protection, security of transfer of earnings, and clarification of arbitration procedures. And above all, transparent energy policies will play a key role in attracting foreign investment. In parallel with government efforts, private companies must seek ways and means to enhance the economic feasibility of regional PNG projects. For example, oil and other mineral resource development could be incorporated into these projects to generate additional revenue.

Northeast Asian economies have been on a fast track of economic development despite the lack of indigenous resources, capital and infrastructure. Many economies in the world esteem the economic achievements in this region. However the economic miracle has not fully blossomed, as the level of achievement has been limited by economic capability and resource endowment. So far there has been no significant regional cooperation for mobilizing natural resources. In particular, each economy in the region has opted to tackle energy and natural resource problems independently without resorting to regional cooperation.

Construction of a regional natural gas pipeline network will create new opportunities and potential economic benefits, as well as providing a solution to environmental problems at global, regional and local levels. It would also lay a solid ground for regional prosperity in the future. Once in place, the regional natural gas pipeline network would contribute to a great extent to enhancing energy security as well as improving environmental conditions in the region.

Starting from 2000 APERC will conduct a second phase study on energy supply infrastructure development in Asia, in an attempt to combine the natural gas pipeline and power interconnection potential, with a view to assessing their complementarity and substitutability.

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GLOSSARY

APEC	Asia Pacific Economic Co-operation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of South East Asian Nations
B98	Base scenario, APERC September 1998
BCM	Billion cubic metres
BP	British Petroleum
Btu	British thermal units
CNPC	China National Petroleum Corporation
CO_2	Carbon Dioxide
EFS	Environmentally friendly scenario, APERC September 1998
EIA	Energy Information Administration (US)
GTL	Gas-to-liquids
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
KEEI	Korean Energy Economics Institute
KOGAS	Korea Gas Corporation
LNG	Liquefied Natural Gas
MITI	Ministry of International Trade and Industry (Japan)
MOCIE	Ministry of Commerce, Industry and Energy (Korea)
Mtoe	Million tons of oil equivalent
PCS	Protracted crisis scenario, APERC September 1998
TCM	Trillion cubic metres
TPE	Total primary energy

APPENDIX

STUDY DESIGN

The following study was developed by Bruce Bawks (currently with the EIA/USDOE) and Junko Ogawa (currently with IEEJ), with significant assistance from Jim Jensen. This study was undertaken in the early stage of the overall APERC research project on natural gas in Northeast Asia, and focused on the relative costs of transporting gas via pipeline or as LNG to China, Korea and Japan. Subsequent to this study, additional factors were incorporated, as contained in the main text of this report. However, the study contained in the Appendix provides many useful insights on the feasibility of the development of a regional natural gas pipeline network.

This study focuses on the relative costs of transporting gas from supply sources to markets in China, Japan, and Korea by both pipeline and LNG. The upstream costs of producing the gas are not included. While the production costs are very critical to the success or failure of a pipeline or LNG project, determining the costs of producing gas in several fields in Asia, Russia, Central Asia, and the Middle East, under a variety of conditions, are beyond the scope of this project. In addition, the comparative economics of pipeline gas and LNG delivery are considered. As such, it has been assumed that the local infrastructure needed to deliver gas to consumers would be the same for either pipeline gas or LNG. For LNG, the costs of liquefaction and re-gasification have been included in the transportation costs. For a more complete discussion of some of the issues and underlying assumptions related to the cost analysis of pipeline and LNG transportation in this study please refer to the APERC Interim Report "Natural Gas Infrastructure Development in East Asia".

Performing a detailed cost analysis for a specific long-distance natural gas pipeline in Asia would require considerable time and resources. For this reason, a 'cookbook' approach was chosen in which volumes, distances, and other parameters can be plugged into a model to develop the transportation costs for a proposed pipeline. A similar methodology is used to estimate delivered costs for LNG, including liquefaction and re-gasification. While these estimates are not as accurate as a more detailed analysis taking into account information specific to a particular locality or situation, the estimates from this approach are considered reasonable approximations in an environment where actual costs are project-specific and can vary from location to location (Jensen, October 1998a).

This study only considers development of a gas grid. It is possible that in China, the development of a power grid along with the gas grid could result in some synergies and more efficient development.

TRANSPORTATION COSTS—THE FOCUS OF THE STUDY

This study focuses on the relative costs of transporting pipeline gas and LNG to markets China, Korea and Japan. The approach is a reflection of the basic issues in the three economies that the study is attempting to resolve.

For China, the questions focus on how to design a gas infrastructure system to deliver natural gas to its energy markets. Given the vast geographic expanse of the country, the presence of limited supplies of domestic natural gas and the difficulty of supplying LNG to the interior, the issue is one of designing an internal pipeline grid that can accommodate both domestic and imported supplies. Therefore, the major questions are:

(1) "Which of the pipeline alternatives provides the most cost-effective method of supplying the total economy?".

(2) "What role does LNG play in the imported gas mix?"

Nearly all of the scenarios compare LNG with pipeline supply within the context of mixed supply 'blends'. For Korea and Japan, the questions are somewhat different. LNG has been the sole source of imported gas. The principal unanswered question has been whether or not pipeline gas offers a viable alternative to LNG to enable these economies to diversify their sources of supply. These scenarios thus compare LNG and pipeline supply directly on an 'either/or' basis.

This study focuses on the comparative economics of pipeline and LNG transportation from the source of gas to market hubs. The upstream costs of production, gathering and processing, and the downstream costs of distribution from the city gate hub to the final customer, are not included. In the case of distribution costs, the working assumptions of the study have been that the issue is one of determining which source of supply is the most economic and that further downstream costs will be unaffected by whichever source is finally selected. While this simplification may not be completely true (particularly in the case of the Japanese gas grid), it enables a relatively straightforward comparison of pipelines with LNG.

NETBACK' VERSUS 'COST-OF-SERVICE' PRICING

In analysing the relative costs of supplying pipeline gas and LNG, an obvious question is, "Why focus on transportation and exclude the cost of gas at the wellhead?" The reasons are fundamental as well as practical.

From a practical perspective, the costs of producing, gathering and processing natural gas vary widely from location to location depending on geology and site-specific conditions. It is far more difficult to make an independent estimate of wellhead costs using generalised or 'cookbook' approaches than it is of pipeline and LNG costs.

From a fundamental perspective, wellhead costs are much less relevant to the choice of supply in a 'netback' pricing environment than they might be in a 'cost-of-service' pricing environment. Gas market pricing in Asia (as is now the case throughout most of the world) is on a market value or 'netback' basis as distinct from a 'cost-of-service' basis.

In cost-of-service pricing, the final selling price is determined by assembling all of the costs (including an allowance for a reasonable return on investment) at each stage of the process. The resulting price is one that provides a reasonable return on investment for the entire product or service. It works best under natural monopoly conditions[31] where there is no competitive pricing established by the market. However, if rigorously applied to a competitive market commodity, it results in different selling prices for the same interchangeable product from sellers with differing cost structures.

In contrast, netback pricing determines a value for the natural gas in the market and then deducts the various costs (often determined on a cost-of-service basis) of transportation to 'net back' the market value to the wellhead. In netback pricing, wellhead costs affect the rate of return on the production investment and determine whether the investor is willing to participate in the market, but they have no direct influence on final selling prices.

The relevance of upstream costs in a netback environment is that they establish how intense the competition is likely to be between sponsors of competing transportation projects. For LNG, for example, in times of high oil prices, and attendant high LNG netbacks, the number of competitors who are likely to offer better terms and conditions increases markedly, even if it is difficult to induce substantial movements in the commodity price of the gas itself. When formula prices are low, as was the case in early 1999, it might be expected that there will be fewer competitive offerings in the market.

[31] An economic activity where declining marginal costs with increasing size give the existing supplier an economic advantage and act as a barrier to effective competition from new entrants.

The widespread adoption of netback pricing for natural gas is based on demonstrated failures of cost-of-service pricing when applied to natural gas production. Cost-of-service pricing has been traditionally used in many economies, notably North America, to regulate utility rates for natural gas pipelines and distribution companies that commonly exhibit natural monopoly characteristics. At one point, the United States extended cost-of-service pricing to the wellhead in order to exert greater control on the final gas selling prices of its regulated pipelines and distribution companies. Canada also experimented with wellhead price controls for natural gas. In both cases, the system ultimately proved to be unworkable, leading to shortages, and is now in disrepute as a means of pricing natural gas production. North America has now abandoned cost-of-service pricing principles at the wellhead, relying on gas-to-gas competition in the field to set market values for gas.

For Asia, where international gas trade has largely been confined to LNG, netback pricing starts from pricing clauses written into the long-term contract between buyer and seller. In Asia, the market valuation of natural gas through gas-to-gas competition is not yet feasible, and the industry has utilised pricing linkages, primarily to oil, to set market prices for natural gas.

One motivation in Korea and Japan for introducing pipeline competition to LNG is to introduce more diverse pricing options as a challenge to the comparatively rigid LNG pricing formulas that now prevail. Analysis of the possible effectiveness of such price-competitive strategies is beyond the scope of this project. However, for those situations where LNG costs are lower than competing pipeline supply, the potential for lowering LNG pricing formulas through pipeline competition is clearly limited.

DEVELOPING LNG COSTS FOR COMPARISON WITH PIPELINE COSTS

Prior to the oil price collapse of 1998, there was very active competition for new Asian LNG projects. Despite subsequent low oil prices, a number of sellers continued to try and sign new contracts. But clearly the cost structures of the competing projects are very different. If costs alone were the overriding influence in determining which projects were successful, it is difficult to see how remote competitors with their high transportation costs (transportation costs from the Middle East to Japan are roughly double those from Malaysia, for example) could remain in the market. But to the extent that they are still active competitors, it suggests that the formula price structure, when combined with their individual wellhead, liquefaction and transport costs, still provides an acceptable rate of return for the overall project investment.

The interaction among these cost elements of an LNG project are illustrated by comparing the changing economics of Southeast Asian and Middle East supplies (using Indonesia and Qatar as examples). Indonesia’s two LNG facilities are located at Arun in Sumatra and Bontang in Kalimantan. Both plants began operation in the late 1970’s for export to Japanese markets. Both facilities have low cost gas supplies and are located relatively close to Asian markets, thus minimising gas production and transportation costs. With expansion over the years the two plants account for fourteen trains, either operating or under construction. But while Bontang still has potential for expansion, Arun is at capacity and may soon go into decline.

Faced with limited expansion potential from its existing facilities, Indonesia attempted to develop an LNG project based on the giant Natuna field in the early 1990’s. While Natuna enjoys Indonesia’s transportation cost advantage to Asian markets, it is very expensive gas because of its 70 percent carbon dioxide content. Its competition came from low production, but high transportation cost supplies from the Middle East. However, even with the higher transportation costs, Middle East gas supplied to Asian markets would still be cheaper than gas from the high cost Natuna field. Not surprisingly, Qatar gas is now commercial but Natuna is not.

Until recently, LNG project developers viewed 3 two-million-tonne LNG trains (or 6 million tonnes) as a minimum size for a green-field project. However, this perception has changed and it is now considered feasible to build a LNG liquefaction train (modelled on the new Trinidad project) as small as a single 3 million tonne unit. This makes it possible for some Southeast Asian fields that would have been deemed too small to support an old style three train green-field facility to compete with Middle East supply. Thus the technology has had an impact on determining which gas sources may be economically developed.

Because individual costs vary so widely among economically viable LNG projects, and because selection of the best LNG projects was not an issue in this analysis, the study elected to use a single hypothetical composite project for its LNG costs. Most liquefaction projects are based on multiple customers, so that the LNG volume required for a specific Chinese, Korean or Japanese scenario does not necessarily determine the size of the liquefaction facility that would ultimately supply it. Accordingly, the study's LNG liquefaction economics for all scenarios are based on a two-train (6.6 million tonne) green-field facility for all projects.

To neutralise the variations in tanker transport costs from the various suppliers, the project chose a distance from Asian markets that represents the weighted average distance from those markets for all existing and contracted Asian supplies. While this would tend to understate the costs of distant suppliers, such as those in the Middle East, it tends to overstate the costs of some of the nearby LNG suppliers. The estimates also include the costs of re-gasification in the market economy (international LNG pricing is commonly done c.i.f. as liquid at the receiving terminal and thus does not include re-gasification).

The result is to put the LNG cost analysis on an internally consistent basis with that of potential pipeline supplies. Each analysis accounts for transportation costs to the market hubs, but neither includes the costs of gas at the wellhead. (Where fuel gas is required, both delivery systems assume that it is available to the project at $1.00 per million Btu in the field.)

DEVELOPING COSTS FOR PIPELINES

The costs of pipeline transportation primarily consist of recovery of the fixed costs and return on the pipeline and compressor station investment. Since pipelines show strong economies of scale, it is important that a given pipeline be carefully sized for the market that it is intended to serve.

For the purposes of this study, it is assumed that regional gas demand is consistent with the APERC EFS and PCS scenarios for 2010 (after accounting for LNG trade) by pipelines specifically sized for the movement involved. Pipeline designs assume a five-year market build-up and operation at a 90 percent load factor.

Because of the capital intensity of pipeline construction, operators try to run pipelines at high load factors. While load factors of 90 percent have used in this study, these are common and are consistent with base load power generation demands, many loads, particularly temperature-sensitive space heating loads, have much lower load factors.

The common practise is to utilise load balancing (or peak shaving) to enable high load factor pipeline gas to serve low load factor consumer demands. Load balancing techniques that are commonly employed include underground storage, interruptible industrial and power generation loads, and peak shaving with LNG or with propane-air mixtures. In general, the costs of load balancing are passed on to the customer who is responsible for the poor load factor, so that comparison of pipeline economics at high load factors is usually reasonable. Estimates of the costs of load balancing in China, Korea and Japan are beyond the scope of this analysis.

PIPELINE DESIGN - THE TRADE-OFF BETWEEN PIPE SIZE AND COMPRESSION

Because of the compressible nature of natural gas, the economics of moving gas in pipelines is sensitive to the way in which the gas compressor stations are designed. For any given pipeline, there is an economic optimum between the compressor horsepower utilised and the size of the pipe.

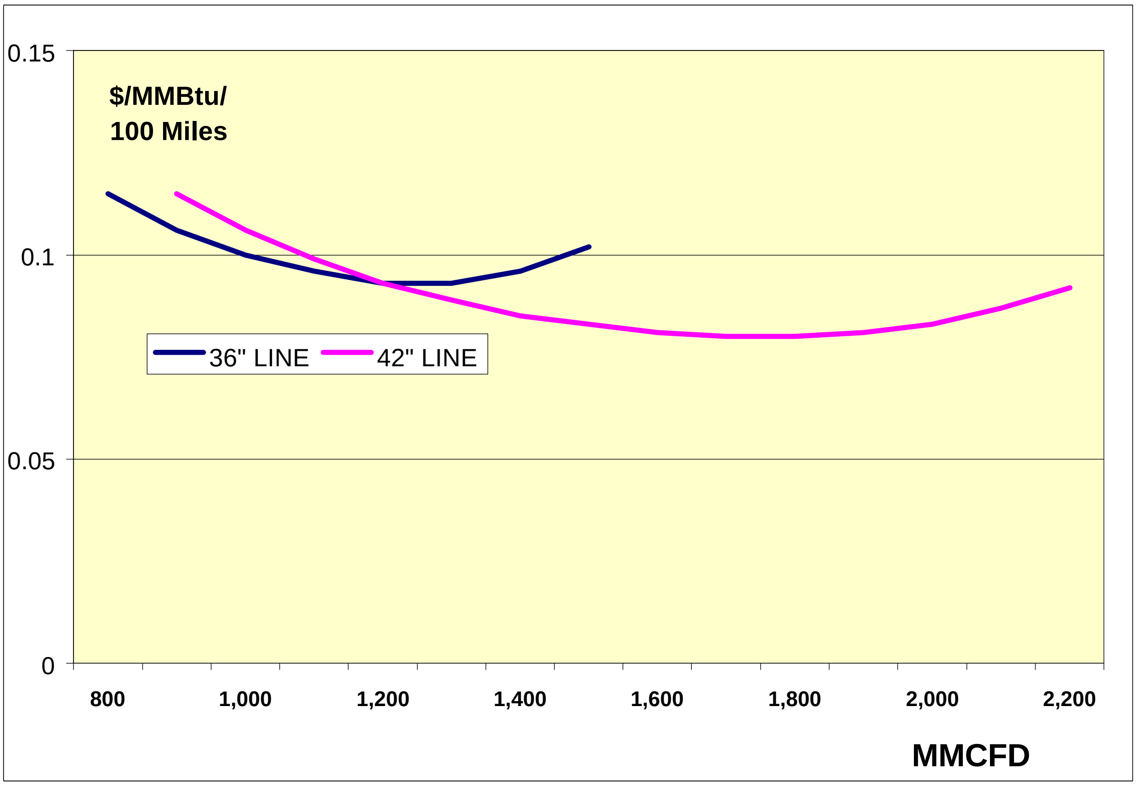
When the pipeline is 'underpowered' (that is too little compression for the size of the pipe) capacity is adversely affected and the pipe is not utilised efficiently. But as compression is added, the unit costs first go down as the throughput increases. However, at some point adding more compression ('overpowering') does not increase capacity as rapidly as it increases costs.

Figure 42 illustrates these relationships for 36-inch and 42-inch pipelines. It is cheaper to move 28 million cubic metres (MCM) per day through a 36" line than through a 42" line, but above 34 MCM per day the larger line is more economic. The importance of these relationships is in designing pipelines for specific markets. While in theory it is desirable to design a pipeline for the optimum capacity for a given market, real markets are seldom static. A designer must decide how much extra capacity to provide to support expected market growth, even if initially the unit costs are poorer than they would have been with an optimised design. Throughout this study, the economic calculations have been based on optimum designs, but a five-year market build-up and a 90 percent load factor at market have been assumed.

THE EFFECT OF DELAYING COMPRESSOR STATION INVESTMENT

One common method of designing pipelines for market growth is to provide for compressor station spacing that is based on optimum designs, but to omit some of the stations when the market load is below design levels.

Figure 42 Effect on cost per 100 miles of increasing gas flow via compressor horsepower



At some point in market growth the line will reach design capacity and additional compression, while increasing throughput, also increases costs. At this point the pipeline operator will consider 'looping' the pipeline. Looping provides parallel pipe between some stations, which, by reducing pressure losses along the line, enable the compressors to handle larger volumes at lower compression ratios.

As the process proceeds, pipe and compression are added alternatively until at some point the pipeline is effectively duplicated throughout its length. There are pipelines in North America that have as many as nine parallel pipes in the same right-of-way.

Designing pipelines to handle market growth illustrates the importance of a full understanding of market potential. Overly optimistic estimates of market growth will saddle the pipeline with the extra costs of idle capacity, but it is also unrealistic to try to design pipelines under the assumption that they will operate for a long time at the idealised economic optimum without the need to add capacity.

TARIFF DESIGN ISSUES

Pipeline operators charge tariffs or rates for transportation. Geographically, there are three broad approaches to tariff design, (1) distance-related tariffs (in North America these are called 'mileage' rates), (2) zonal tariffs, and (3) 'postage stamp' tariffs. Mileage tariff reflect the distance over which the gas must travel, the most distant customers paying the highest tariffs. With zonal tariffs, on the other hand, all customers in a given region or 'zone' pay the same tariff. More distant zones will have higher tariff structures, so that zonal tariffs are also partially distance-related. In the extreme case the zone encompasses an entire country and the tariffs are known as postage stamp rates. Postage stamp and zonal tariffs involve cross-subsidies, since the more remote, and thus more costly, customers pay the same rate as those whose gas moves over shorter distances.

The issue of tariff design will prove to be important in China. The Changjiang Delta, with Shanghai at its hub, is a very large market that in most cases will be at the most expensive end of the pipeline. Shanghai is also a potential LNG terminal location. In many of the cases studied in this report, mileage rates for pipeline supply would provide more costly gas to the region than would LNG supply. However, the loss of the Changjiang Delta market to LNG would significantly raise the costs of supply to other regions because of the scale effects caused by the loss of the Shanghai market. There are a number of other tariff design issues that are important in North American and European markets involving the relationship between charges for reserving pipeline capacity and charges for actual usage (demand/commodity issues). These were not important considerations in this study.

OPEN ACCESS ISSUES

The liberalisation of natural gas regulation in North America and Europe has featured 'open access' or 'third party access' (TPA) issues. These policies, which are being strongly advocated as a part of the liberalisation of international trade, may have significant implications for the possible delivery of Russian gas to Korea and Japan via China.

Under the traditional industry structure, which prevailed before regulatory restructuring, pipelines contracted for gas supply and, by 'bundling' gas transportation with the gas itself, effectively acted as monopoly merchant sellers of the commodity to customers on their systems. As a result, the customers were exposed to the tariff design treatment that the pipeline merchant chose to exercise in the sale. Pipelines could, in their sales contracts, accommodate special problems raised by the sale, or recapture any extraordinary costs represented by the transaction. Customers usually had no knowledge of the actual supply transactions required to match their increased demands on the delivery system.

This capability has a special value in the gas industry, where 'transactional' movements of gas do not necessarily reflect physical movements. A customer who is permitted, through open access policies to contract directly with a remote supplier, will often not receive his gas directly, but through exchange or displacement. That is, the physical supply he receives is actually diverted from another nearby supplier and the volumes that he thought he had purchased are delivered to another customer located nearer his new supplier.

Table 49 Principal working assumptions for pipeline and LNG cost study

	Units	Common Onshore Pipeline	Japanese Rural Onshore Pipeline [1]	Japanese Metro Onshore Pipeline [2]	Common Offshore Pipeline [3]	High Pressure Offshore Pipeline [4]	Japanese Offshore Pipeline [3]	Lng Liquefaction Plant [7]	Lng Liquefaction Tankers	Lng Regas Terminal
Project Life	Years	35	35	35	35	35	35	20	-	35
Target Real IRR	Percent	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	-	10.0%
Capital Charge	Percent	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	11.7%	10.0%	10.4%
CAPEX	$M/Inch Kilometre [5]	$21.3	$116.7	$150.0	$28.8	$42.7	$33.3			
	$MM/Station [6]	$12	$24	$24	$16	$24	$24			
	$/Horsepower [6]	$1,250	$1,167	$1,167	$1,688	$1,688	$1,688			
	$MM/Riser Platform					$60				
	$MM/Greenfield Site [6]							$150		
	$/Metric Tonne [6]							$250		
	$MM/Ship (130)								$200	
	$/Regas Plant (6 MMT)									$500
OPEX as a Percent of CAPEX	Fixed Percent	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.5%	3.6%	2.5%
	Variable Percent	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%			
OPEX – Fuel	Percent/100 Miles	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%			
	Percent							9.0%		2.5%
	Boiloff Percent/Day								0.17%	
	Added Bunkers								Varies	
OPEX – Port Charges	000$/Voyage								$160	
Income Tax Rate	Percent	25%						25%	0%	25%

[1] Costs in areas other than the Kyushu-Tokyo corridor
[2] Costs in the Kyushu-Tokyo corridor
[3] Common offshore lines have access to normally spaced compressor stations, either land-based or on riser platforms
[4] Newer high pressure lines can be utilized where normal compressor station spacing is impractical or uneconomic
[5] Pipeline investment equals the constant times the length and times the diameter of the pipeline in inches
[6] Includes a fixed cost per installation plus a variable cost per unit of capacity
[7] Based on a two-train (6.6 million tonne) greenfield facility

This issue was raised in Europe in the 1980s, when OMV, the Austrian gas utility, was interested in diversifying away from heavy reliance on Russian supplies. It wanted to contract directly for Norwegian gas, which would have to be delivered through Germany by Ruhrgas. Ruhrgas preferred to sell the diversified supply to OMV under traditional practices as a merchant from its own contracted system supply. But had there been a supply disruption, OMV as a merchant customer would presumably have taken its proportionate share of any curtailment that Ruhrgas, the largest individual purchaser of Russian supply, would have had to implement.

Ruhrgas resisted the direct purchase on the grounds that Norwegian supply could not physically reach the eastern part of its system in the event of a severe Russian supply disruption since the gas was actually to be delivered to OMV by displacement. The two companies worked out an agreement in which OMV effectively contributed to a de-bottlenecking of the Ruhrgas system so that supply could reach OMV physically as well as per the contract. The way in which open access currently operates, by requiring the third party shipper to have title to capacity as well as the gas, would have mitigated this problem directly.

The issue in the possible transit of Russian gas through China to Korea and Japan poses a somewhat different, though related problem, which arises in the larger demand scenario (EFS C1). It assumes that China will utilise Irkutsk gas preferentially and delay the development of supplies from West China. In that case the addition of re-exports of Irkutsk gas to Korea (EFS CK1) forces China to develop its higher-cost West China supplies for itself as a replacement for the diversion of lower-cost Irkutsk gas to Korea.

If China were to act as a merchant in traditional gas industry practice, it would be able to recapture some of its higher West China costs in its merchant sale price for export, despite the fact that the gas physically would originate in Irkutsk. (The estimates in this study assume that such a recapture would be possible.) However, if open access rules apply, Korea could access the lower-cost Russian supply directly while Chinese markets were absorbing the supplies from West China.

ASSUMPTIONS UTILIZED IN ECONOMIC CALCULATIONS

This study has utilised a series of assumptions about representative costs in preparing the economic analyses in this study. A summary of some of the key assumptions is included as Table 49.

RATES OF RETURN

Minimum acceptable rates of return (sometimes called 'hurdle rates') have been based on real (constant dollar) internal rates of return (IRRs). Real rates are lower than the nominal rates of return that are often used by those who adjust a forecast of future cash flows for inflation. In order to make the comparison of pipelines and LNG projects internally consistent, the study essentially utilised the same hurdle rates for both pipelines and LNG. After discussions with a number of industry people, Jensen Associates Inc selected the lowest end of the range (10 percent) that might be considered acceptable by the industry as the best way to compare these projects. It is important to recognise that some investors would require higher rates than these before they would consider investment.

PIPELINE INVESTMENT

Throughout the study, pipeline economics were based on an estimate of the capacity required to deliver gas at a 90 percent load factor after a five-year market build-up. The basic pipeline investment was based on an assumption of $21.3M ($6.50 per inch foot) for pipe in normal onshore conditions. These costs were adjusted for various offshore and Japanese configurations. Compressor station costs were broken down into a cost per station plus a cost for installed horsepower based on the installed horsepower in the station.

LNG INVESTMENT

LNG transportation facility investments are shown in Table 49. Liquefaction plant investment assumes a cost of $150 million for infrastructure in a green-field facility and $250 per metric tonne of capacity. All LNG regardless of scenario size was assumed to be produced in a new 6.6 million tonne facility located at the 'balance point'—the weighted average distance from market of all Asia Pacific contracts. Shipping and re-gasification were sized to the particular trade.

THE COMPARATIVE ECONOMICS OF LNG AND PIPELINE SUPPLY

Any comparison of the relative economics of serving natural gas markets with LNG or with pipeline gas must start with a recognition of the importance of economies of scale in moving gas over long distances. Scale is particularly important in pipeline economics and since LNG projects tend to come in minimum-sized modules there is usually a threshold market size below which LNG as well as pipeline gas supply is no longer feasible. Hence, small markets and small gas discoveries are at a substantial economic disadvantage when gas must be moved over a long distance.

Figure 43 shows representative[32] costs of moving gas as LNG and in pipelines of varying capacities and construction environments. The sharp reduction in unit costs of moving gas onshore in a 56" line compared to that in a 36" line is evident, but one must also keep in mind that the larger line carries three times as much gas as the smaller one.

Despite substantial recent improvements in the technology of offshore pipelining, it still costs more than onshore pipeline transmission. Conventional pipelines require frequent spacing of compressor stations for best economic performance. Transiting long offshore distances, or in deep water where compressor riser platforms were impractical or uneconomic,[33] was not possible until recent developments in high-pressure offshore pipelining technology made such pipelines feasible. Figure 43 illustrates the comparison between the same sized line in onshore, near offshore and high-pressure configurations.

Japan presents special problems in pipeline delivery. The regional urban congestion coupled with the lack of eminent domain[34] legislation makes onshore pipeline construction extremely expensive. Figure 43 also shows the cost of moving gas in Japan in rural areas.

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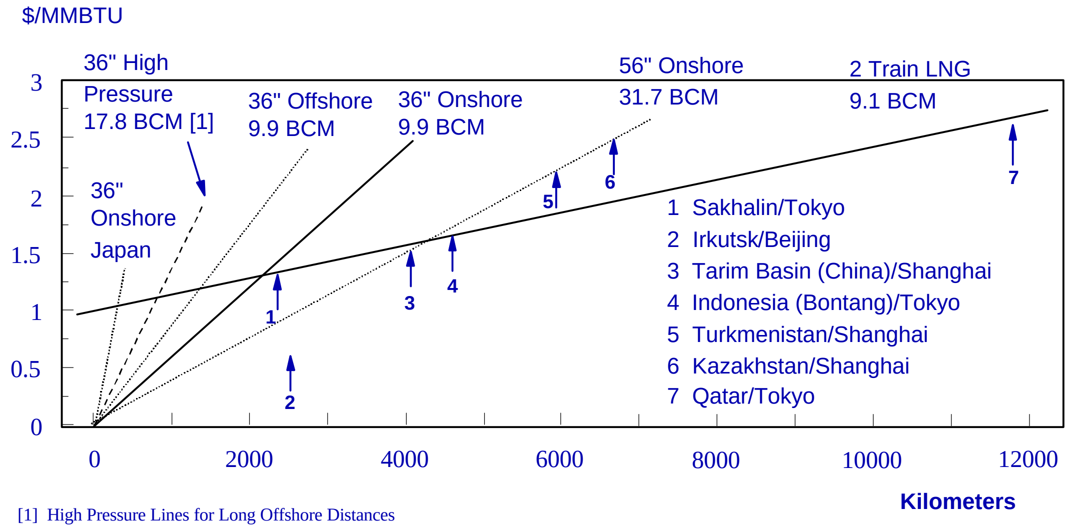
32 Costs shown are 'representative,' that is they are reasonable approximations in an environment where actual costs are project-specific and can vary from location to location based on local conditions. LNG transportation costs include the costs of liquefaction and regasification as well as tanker transportation costs.

33 In contrast, 'conventional' offshore lines permit normally spaced compressor stations either through periodic shore landing or shallow water compressor platforms.

34 Eminent domain permits a government to take access to property for a fair valuation if it is in the public interest.

Figure 43 Representative costs of natural gas transportation as a function of distance



[1] High Pressure Lines for Long Offshore Distances

COMPARISONS BETWEEN CHINA AND JAPAN/KOREA

Comparing the economics of LNG with pipeline gas requires a different approach for China than for Korea and Japan. For Korea and Japan, which at present are solely dependent on LNG for their imported natural gas, pipeline imports represent supply diversification. As natural gas demand increases in the future, supplies can be assumed to come from either LNG or pipeline gas. Thus scenarios can be developed which assume similar volumes of either LNG or pipeline gas providing future gas needs.

For China, however, the geographic expanse of the country, the need to accommodate domestic supplies, and the difficulty of delivering LNG to the interior, indicate that LNG will only be one element of the emerging supply mix. The comparative economics of LNG supply must therefore be judged by the way in which it interacts with pipeline supply in the various gas pipeline infrastructure proposals that are under consideration.

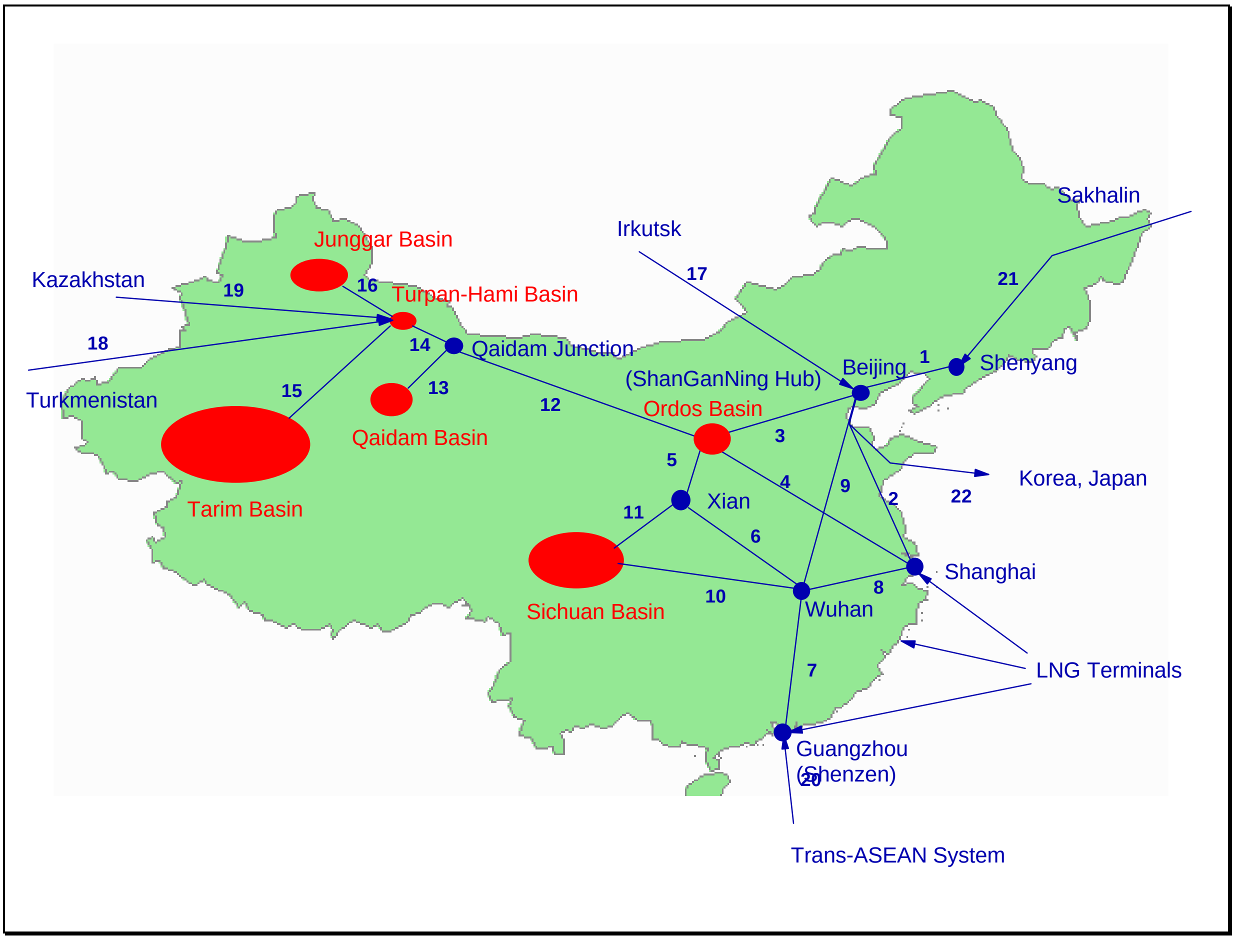
THE SCENARIO APPROACH TO ECONOMIC COMPARISON

To compare LNG and pipeline economics, this study examined fifteen supply/demand scenarios in order to provide an 'economic mapping' of the various options. The scenarios feature two different levels of projected demand based on APERC forecasts for the region. The large volume scenarios are based on the EFS projections while the small volume ones are based on the PCS forecasts.

Thirteen of the scenarios focus on Chinese markets. Of these, four supply Korea and two supply Japan as well. In addition to the two Chinese re-export scenarios, Japan is also the target for two scenarios involving direct imports from Russia's Sakhalin Island. Figure 44 illustrates both the internal sources of gas supply in China as well as the sources of pipeline imports considered in the various scenarios. These pipeline imports include Irkutsk and Sakhalin in Eastern Russia, Turkmenistan and Kazakhstan in Central Asia, and attachment to the proposed Trans-ASEAN system originating in Southeast Asia. The scenarios also consider LNG imports into Guangzhou (Shenzhen) and Shanghai.

The approach utilised in the study consists of comparing the costs of delivering pipeline supply and LNG to key regional consuming centres or 'hubs'. For example, Wuhan is taken as the 'hub' for supplying consumption in the Central South China region. These consumption hubs, as well as several that represent junctions where several pipelines come together, are also shown in Figure 44.

Figure 44 China - pipeline destinations and hubs



The large volume Chinese scenarios were further subdivided by whether or not they emphasise imported eastern supplies for eastern markets or instead envision development of the Tarim, Junggar, Turpan-Hami and Qaidam basins in West China. This is illustrated in Figure 45. The two eastern import scenarios rely on Irkutsk (EFS C1) and on the Trans-ASEAN system (EFS C2) to meet market demand. In those large volume cases where West China is developed, supply must be supplemented by imports as well. These can be from the east (Irkutsk—EFS C3) or from Central Asia (Turkmenistan—EFS C4 or Kazakhstan—EFS C5). The one large volume re-export scenario (EFS CK1) also assumes West China development.

Among the scenarios that do not involve re-export, the Irkutsk (EFS C1) and West China scenarios (EFS C3) provide the lowest cost supplies to China. Because they are the lowest cost cases, either of these scenarios might be viewed as a point of departure for pipeline development, depending on Chinese policy towards early development of West China. They are thus referred to as the 'reference cases'.

Figure 45 Chinese scenario studies including numbered designation (large volume cases)

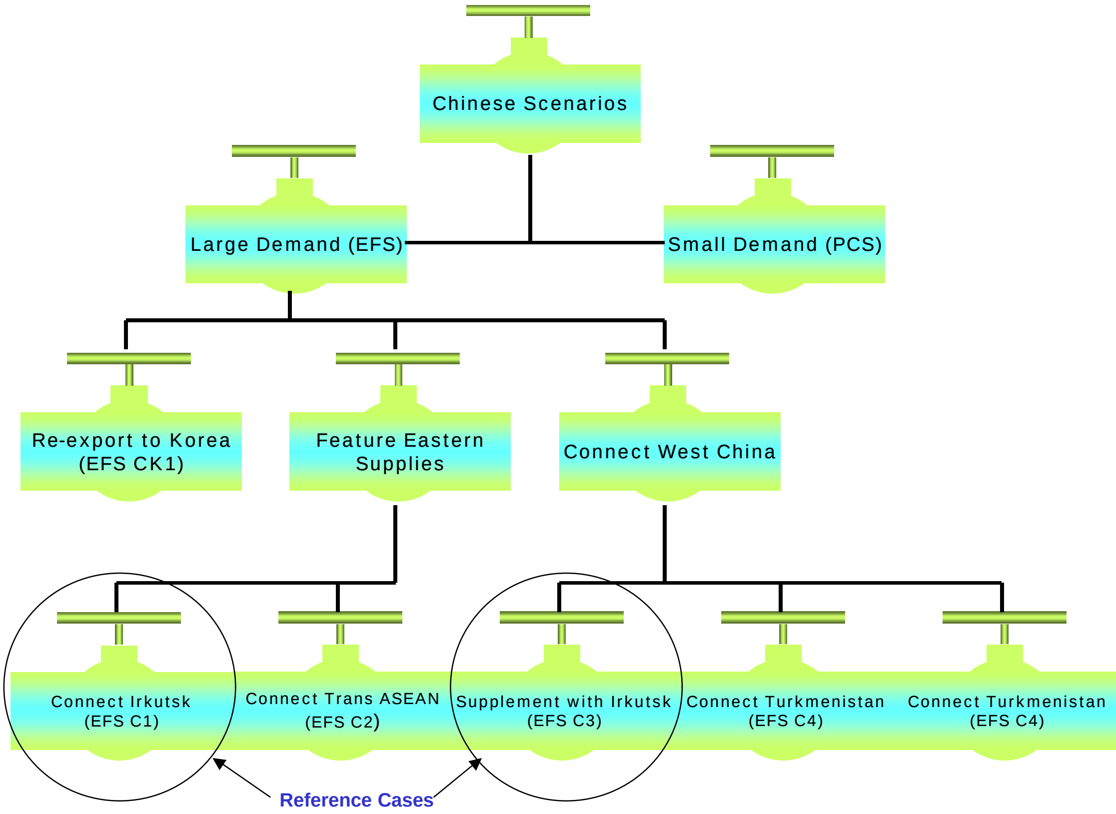


Figure 46 lists the scenarios in the small volume cases. In the case where West China development is considered (PCS C1), no imports are required. It is also possible to envision a scenario (PCS C2) that relies entirely on LNG for imported supply. The two pipeline import scenarios consider supplies from Irkutsk (PCS C3) and Sakhalin (PCS C4). The West China (PCS C1) and the Irkutsk (PCS C3) scenarios again represent the lowest cost sources for Chinese markets (for those scenarios with no re-export) and can be considered the 'reference cases' for comparison with other alternatives.

In one of the three re-export scenarios (PCS CK1), the pipeline is extended only to Korea. The other two scenarios (PCS CKJ1 and PCS CKJ2) explore the economics of additional exports to Japan. They are also based on the small volume projections. The Korean scenarios envision a landing point near Inchon, the location of one of Korea's major LNG terminals. Where further export to Japan is assumed, the scenarios are based on the construction of a new trunk pipeline to Pusan with a water crossing to Kita Kyushu in Japan. Although there is an existing pipeline link between Inchon and Pusan, it does not have the capacity necessary for re-export. While other routes have been proposed, these were deemed the most plausible. The Korean routings are shown in Figure 47. The Korean scenarios, which are all derived from the Chinese cases shown in Figure 45 and Figure 46 are shown as Figure 48.

Figure 46 Chinese scenarios studies including numbered designation (small volume cases)

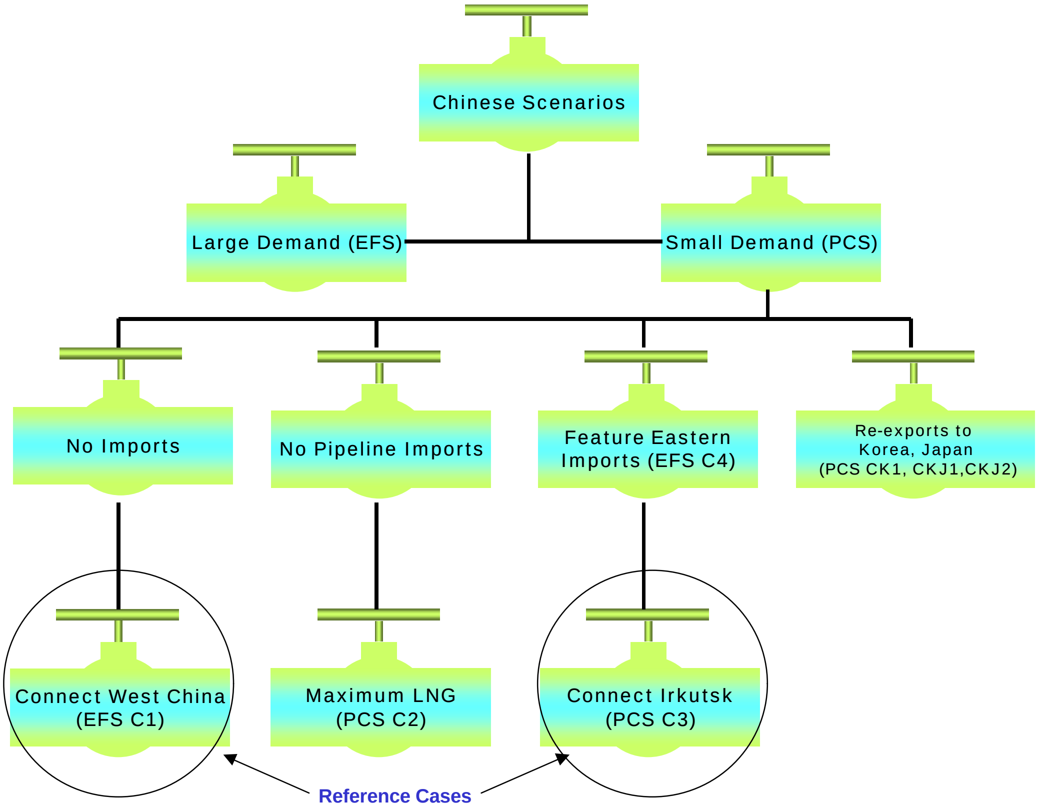


Figure 47 Korean pipeline configurations

Figure 48 Korean scenario studied including numbered designation

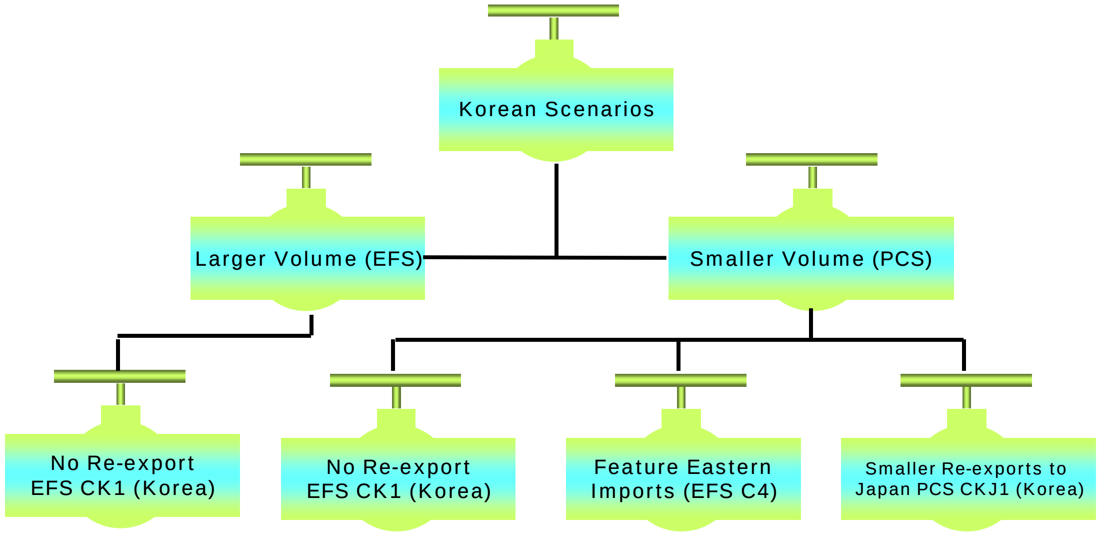


Figure 49 Japanese pipeline supply options

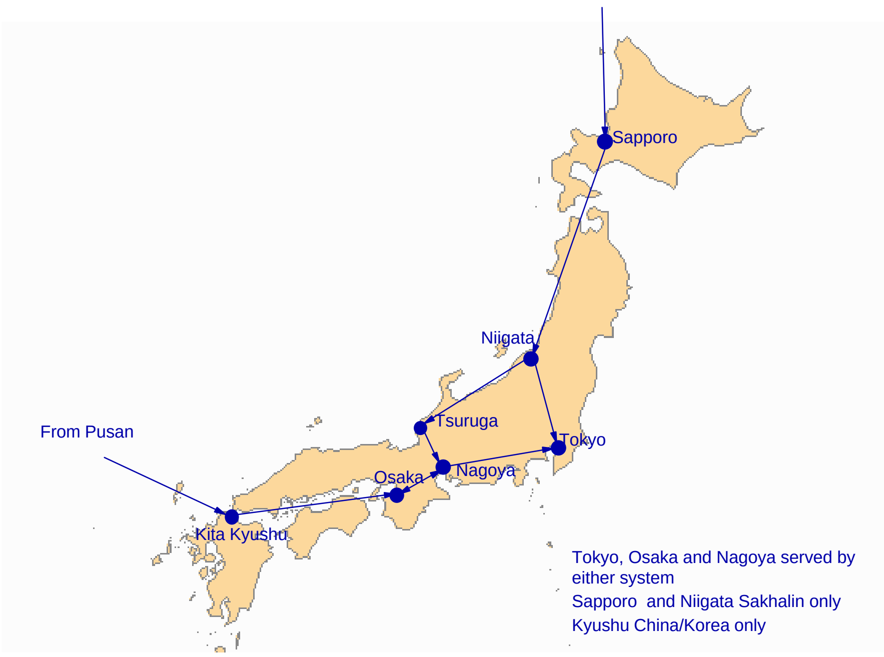


Figure 49 and Figure 50 outline the Japanese scenarios. Two of these assume re-export from China and Korea while the other two assume direct delivery from Sakhalin. Both projects are designed to serve the major metropolitan areas of central Honshu - Tokyo, Osaka and Nagoya. Landing in the south from Korea enables the Chinese re-export cases to serve Kyushu and the Chugoku region of southern Honshu as well. In the Sakhalin scenarios, shipments serve Hokkaido (Sapporo) as well as the Tohoku region of northern Honshu. The Japanese scenarios envision two levels of Japanese pipeline demand, 9.36 BCM and 16.12 BCM.

Figure 50 Japanese scenarios studied including numbered designation

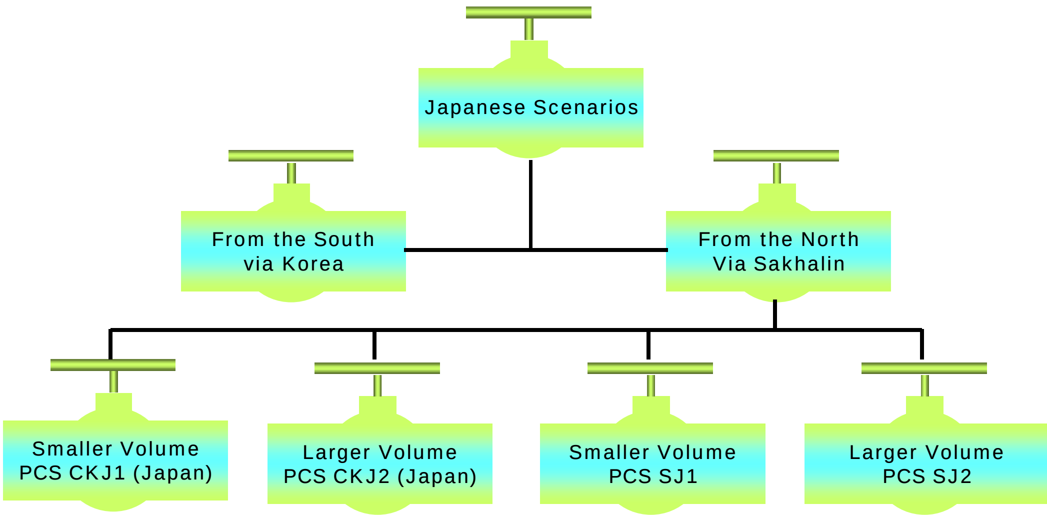


Table 50 provides a summary of the scenarios, showing the primary source of supply and the pipeline imports into each economy.

CHINESE REGIONAL BALANCES

China was divided into eight regions for this analysis. In 2010, Chinese supply/demand balances for four of these regions are projected to be in deficit, while the other four regions are potentially in surplus. The largest deficits are in the Changjiang Delta (Shanghai), Bohai/Beijing, Central South China (Wuhan) and Northeast China (Shenyang) regions.

Figure 51 illustrates the magnitude of the deficits. The figure compares the projected lower volume (PCS) demands and the higher volume (EFS) demands with maximum expected regional production. The maximum resulting deficits (measured against the larger EFS demands) are also shown. The deficits would be smaller when measured against the PCS volumes. The largest individual regional deficit is that for the Changjiang Delta. The deficits for the Bohai/Beijing, Central South and Northeast regions are somewhat smaller, though still significant.

Figure 52 shows similar information about the supply-surplus regions. In this case the surplus is measured against the lower PCS demands to indicate the largest potential surpluses. The West China basins represent the largest regional surpluses. The South region's large production provides a surplus in the lower demand (PCS) cases, but if consumption levels were to reach the higher EFS projections, the region would instead be in deficit.

Table 50 Pipeline import volumes by scenario

Scenario	Primary Source	Volume (BCM)	Pipeline imports by economy (BCM)		
			China	Korea	Japan
PCS C1	West China	15			
PCS C2	[LNG]	[15]			
PCS C3	Irkutsk	15	15		
PCS C4	Sakhalin	15	15		
PCS CK1	Irkutsk	22	15	7	
PCS CKJ1	Irkutsk	32	15	7	9
PCS CKJ2	Irkutsk	32	5	11	16
EFS C1	Irkutsk	32	32		
EFS C2	Trans-ASEAN	32	32		
EFS C3	Irkutsk	25	25		
	West China	16			
EFS C4	Turkmenistan	32	32		
	West China	17			
EFS C5	Kazakhstan	32	32		
	West China	17			
EFS CK1	Irkutsk	31	19	12	
	West China	16			
SJ1	Sakhalin	9			9
SJ2	Sakhalin	16			16

Figure 51 Regional supply/demand balances – 2010 (the supply deficit regions)

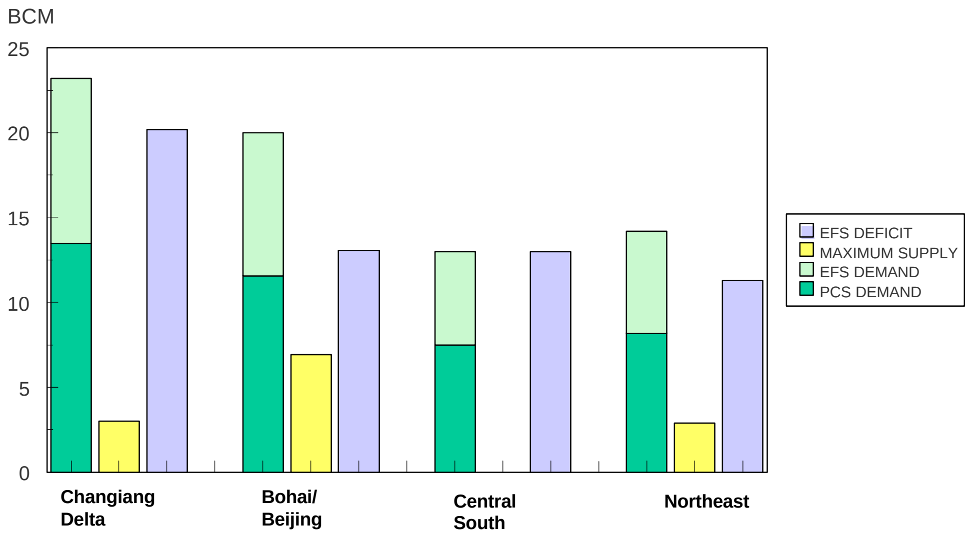
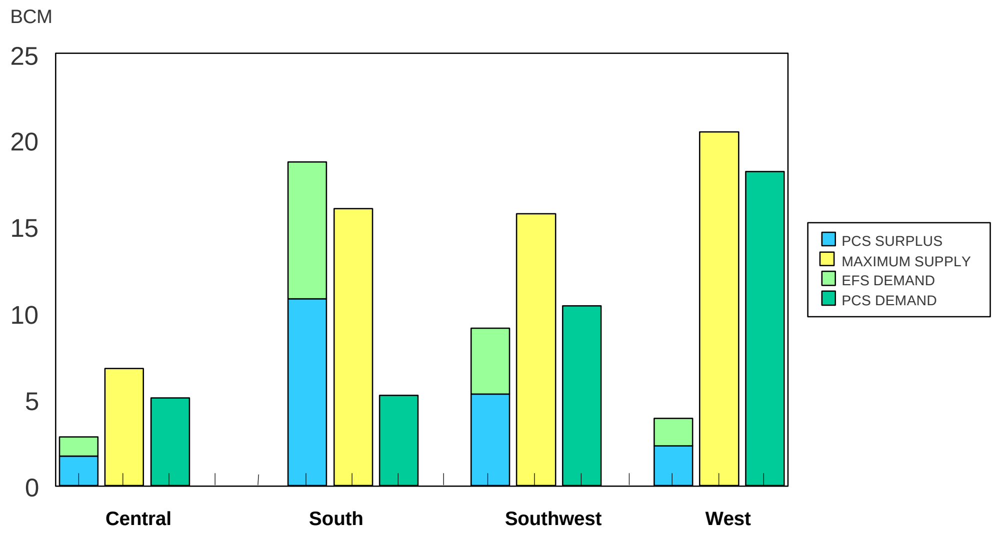


Figure 52 Regional supply/demand balances – 2010 (the supply-surplus regions)



The Ordos and Sichuan basins are natural sources of supply for several deficit markets. For most of the scenarios, the Ordos basin supplies the Bohai/Beijing and Northeast regional markets. A pipeline connecting ShanGanNing in the Ordos basin with Beijing currently exists and is operating below design capacity. The Sichuan Basin is a natural source of supply for the Central South market with Wuhan as its hub. The four major basins in West China, however, have no local market. Figure 53 illustrates these regional patterns.

Since the Changjiang Delta (Shanghai) does not have regions with potential surpluses nearby to offset its deficits, as do the Bohai/Beijing, Northeast and Central South regions, it is the predominant destination for major pipelines. In most of the large volume (EFS) cases, the region represents nearly half of the potential market for remote pipelines (see Figure 54). In the smaller volume (PCS) cases, it represents nearly two-thirds of the large-scale pipeline 'anchor' market.

Figure 53 Preferred pipeline destinations for Chinese domestic gas supply

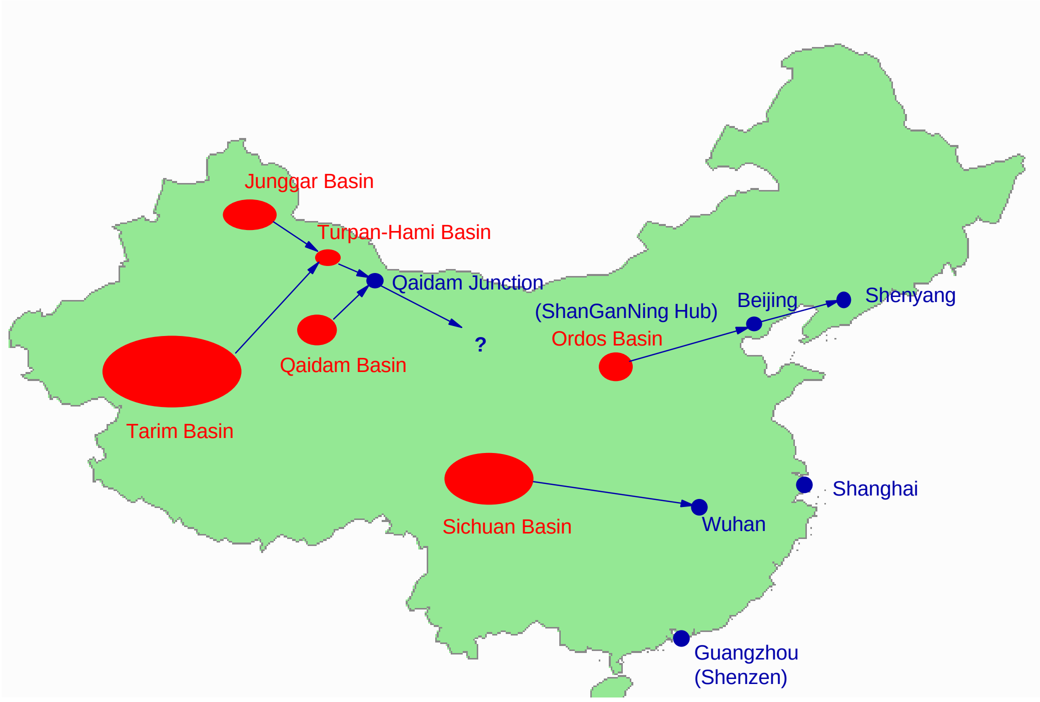
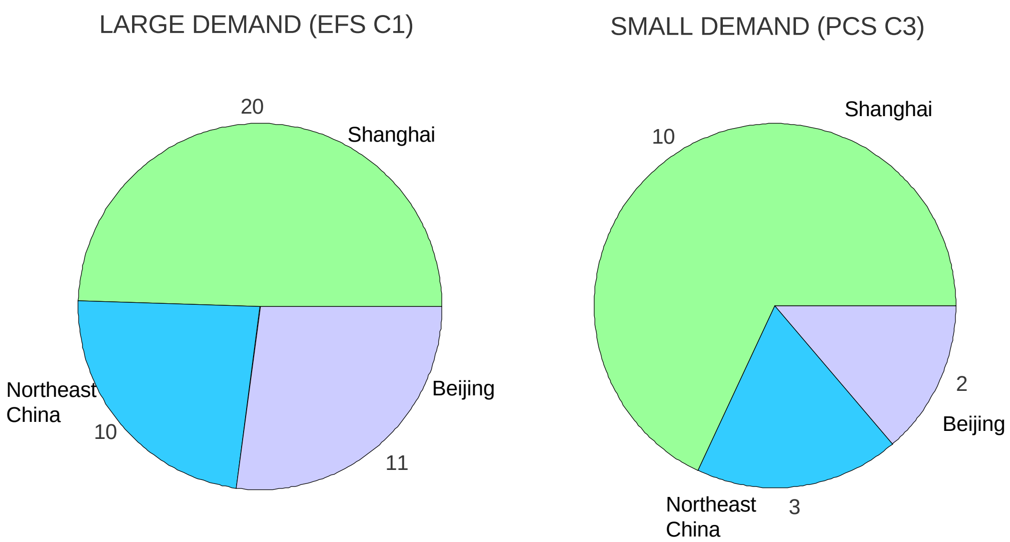


Figure 54 Regional share of "Anchor Market" for remote pipeline supply in 2010



Notes: Net of Ordos and Sichuan basin surpluses

THE MAJOR CHINESE PIPELINE SUPPLY OPTIONS

Twenty-nine percent of total potential Chinese production capability and forty-seven percent of the potential supply available to move between Chinese regions in 2010 is expected to originate in West China. The Tarim, Junggar, Turpan-Hami and Qaidam basins in West China constitute a significant potential source of gas for meeting Chinese gas requirements.

However, because of the project sizes and distances from market, the West China pipeline projects more nearly resemble import pipelines than those from the Ordos and Sichuan basins. For example, the West China pipeline investment is larger than that required to supply a similar amount of gas from Sakhalin, and is nearly as large an investment as the largest of the Irkutsk projects, but has only half the supply capacity. Figure 55 illustrates this point, comparing the capital investment required for various domestic and export pipeline projects.

Because of these high capital costs, the delivery of gas to Chinese markets from West China is more expensive than it is from Irkutsk. The distances from the Tarim basin in West China to Shanghai are somewhat farther than they are from Irkutsk, but they are much farther from Beijing. In addition, gas must be assembled from a number of basins in West China for a major trunk pipeline to the east. The gas from Irkutsk would originate, initially at least, in the giant Kovyktinsk field. Also, the volumes available from Irkutsk exceed those available from West China, giving Irkutsk a scale advantage for the larger scenarios. The comparative economics of West China and Irkutsk supply to China (overall average), Beijing and Shanghai are shown in Figure 56.

Figure 55 Selected capital expenditures on pipeline projects

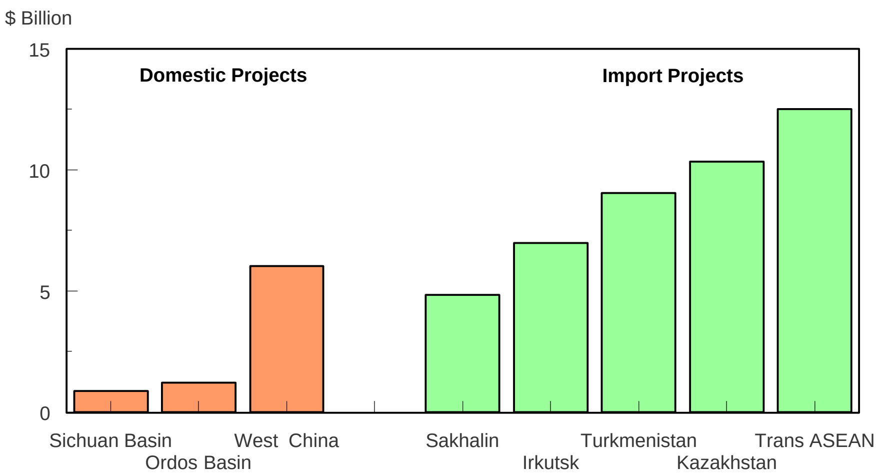
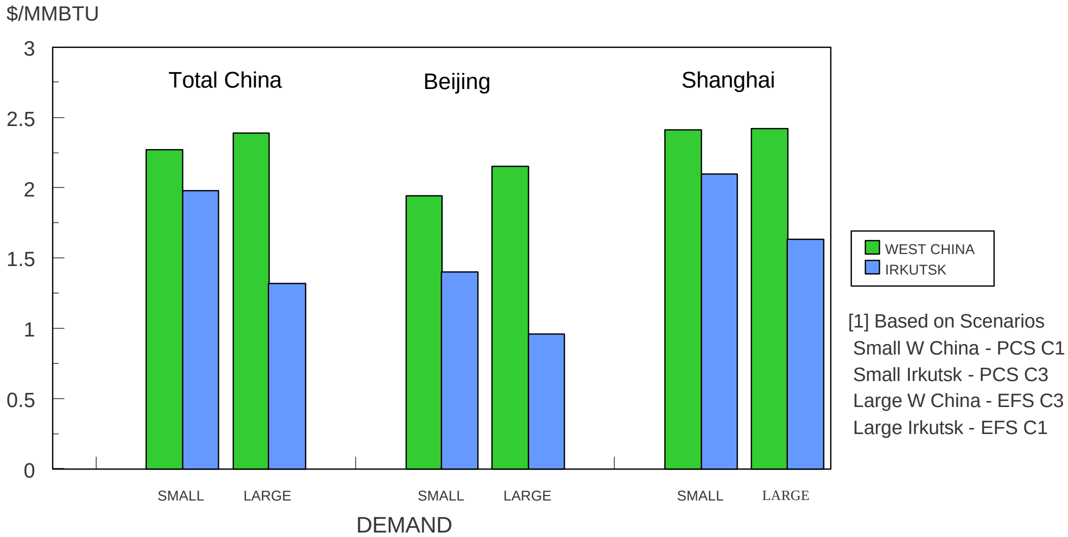
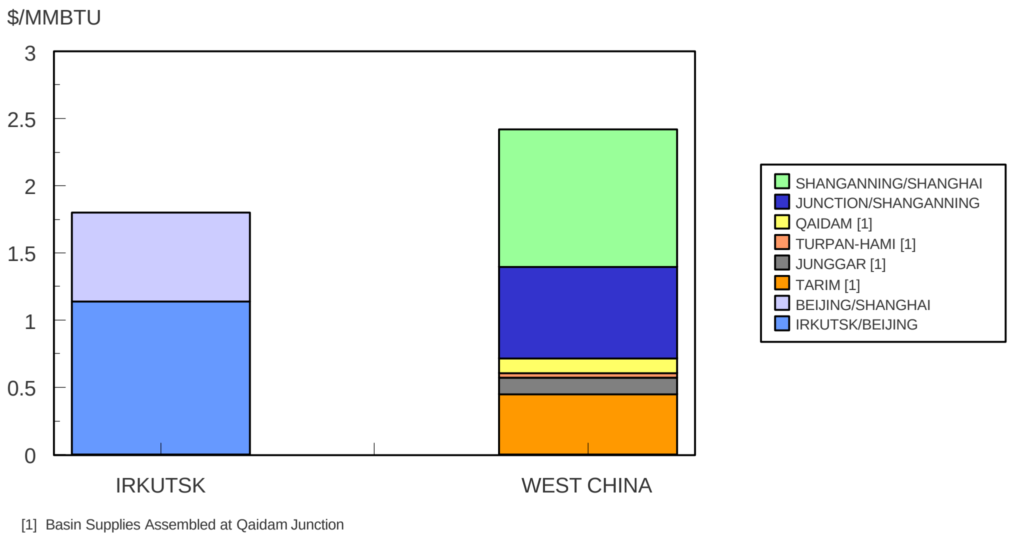


Figure 56 An economic comparison of the costs of delivering West China and Irkutsk gas



For Shanghai, which is the target market for most large pipeline projects, the higher costs of West China supply largely reflect the costs of assembling gas from the various supply basins at a common point (which can be termed the 'Qaidam Junction'). From there, a large diameter pipeline can be utilised to the ShanGanNing hub in the Ordos basin and on to Shanghai. The breakdown of delivery costs to Shanghai from the two supply areas is shown as Figure 57.

Figure 57 Comparison of the costs of delivering Irkutsk and West China gas to Shanghai



Notes: Large Volume Scenario EFS C3

Of the major remote sources of gas for Chinese markets, Irkutsk provides the lowest cost supply in both the large (EFS) and the small (PCS) demand scenarios. The next lowest cost supplies for both the large and small demand cases are those that emphasise the development of West China. These four cases, involving two different demand levels and two different supply sources, are thus the scenarios against which all other options can be judged. These have been termed the 'reference cases'.

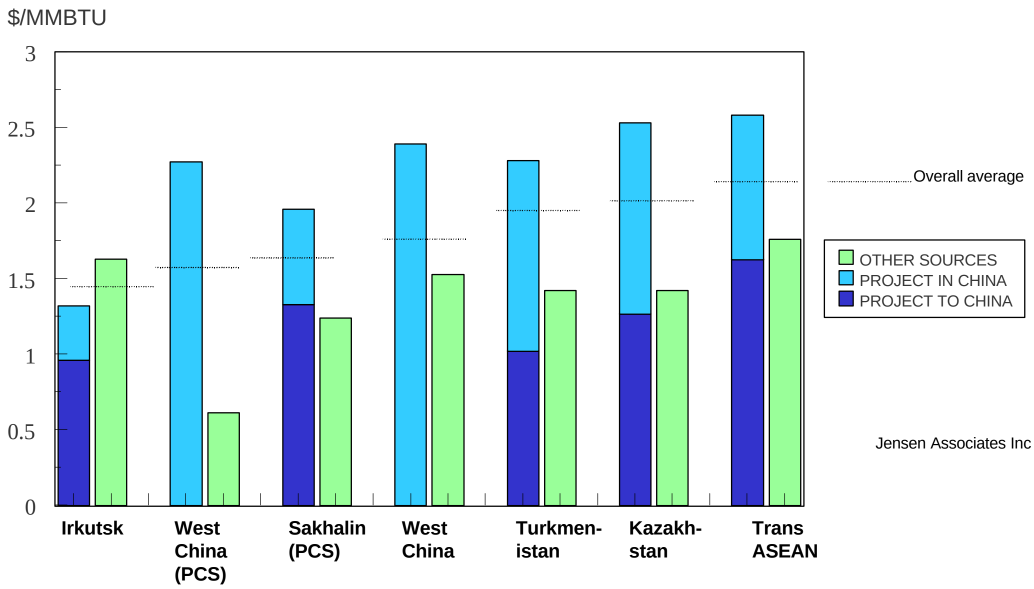
This indicates that, if the decision were based solely on the cost of transporting the gas from the source to the markets,[35] Chinese policy makers would choose Irkutsk over West China as the source of remote gas supply. However, the decision will involve such issues as foreign affairs, balance of payments and the cost/benefit implications of developing domestic gas reserves. After taking these issues into account China might well elect to develop West China first.

This study has also examined pipeline import options from Irkutsk, Sakhalin, Turkmenistan, Kazakhstan and the proposed Trans-ASEAN system. The comparisons have been made in the large volume scenarios except for Sakhalin, where available gas reserves are most likely to limit the size of a Chinese export project. In the large volume scenarios, it is possible to accommodate both West China development and some pipeline imports, either from Irkutsk in the east or Turkmenistan and Kazakhstan in the west. However, scenarios involving maximum-sized 56" eastern pipelines assume that West China development will be postponed. In the small demand scenarios where re-export is not considered, the development of West China or of pipeline imports are mutually exclusive alternatives in this analysis.

Figure 58 presents a summary of the costs of delivering interregional gas to Chinese markets. Shown separately are the costs of importing the remote gas to the Chinese hub, the costs downstream of the hub to further distribute the gas, and the costs of all other supplies.

While Irkutsk and West China offer the lowest cost gas supplies for both the large and small volume cases, the small volume Sakhalin scenario actually shows lower costs than the larger West China case. This is because the small volume cases minimise the need for more distant and more costly remote supplies. The remaining import options—Turkmenistan, Kazakhstan and the Trans-ASEAN system - provide the highest cost gas of any of the scenarios considered in this study.

Figure 58 Costs of gas from major distant supply sources



Notes: Large projects unless noted

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35 These estimates do not include the cost of gas at the wellhead, which could shift the relative ranking of sources.

THE ROLE OF LNG IN THE CHINESE SUPPLY MIX

In one of the small volume scenarios (PCS C2), LNG is considered as the sole source of imports. However, the cost of shipping LNG inland makes this a more expensive option, for China as a whole, than developing West China gas or importing from Irkutsk. Figure 59 compares PCS C2 with both of the other small volume reference scenarios.

In the reference cases, LNG is more costly than other supplies in the overall Chinese mix. Figure 60 illustrates the relative costs of LNG, West China, Irkutsk and other supplies for three of the four reference cases. (In the low demand West China reference case, PCS C1, no LNG is imported). Although a direct comparison of LNG with other supplies places LNG in an unfavourable competitive light, the estimates included in Figure 60 do not place an 'opportunity cost' on the LNG. That is, they do not show the costs of replacing the LNG in the mix with other supplies.

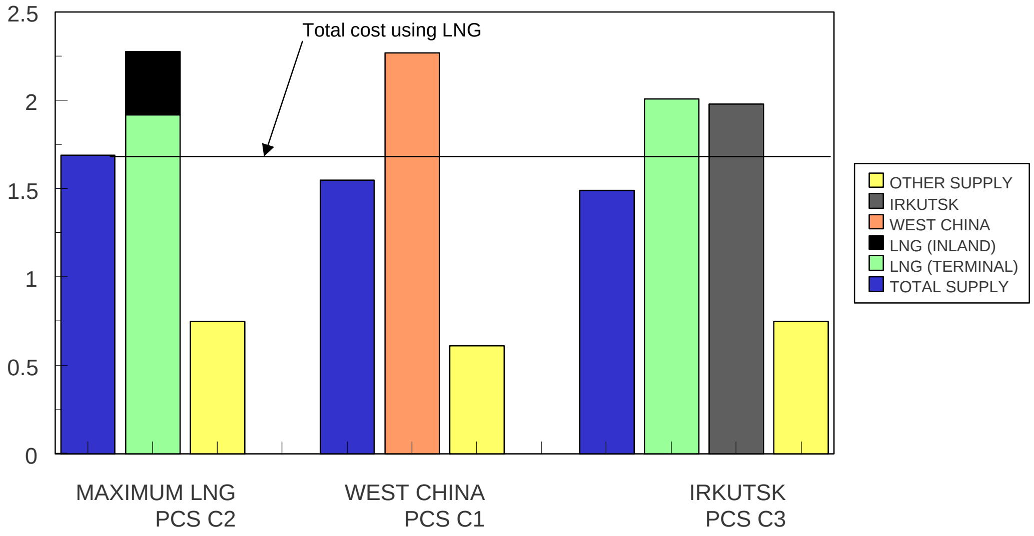
In Figure 60, the lower cost of Irkutsk and West China supplies is achieved through economies of scale by reserving the Changjiang Delta 'anchor' market for large pipeline delivery. Shanghai itself would usually find LNG cheaper than either West China or Irkutsk gas, if charges for pipeline delivery were based on distance-based mileage or zonal tariffs.[36] However, if Shanghai chose LNG over pipeline gas, the cost of gas to the rest of China would increase.

The costs of West China and Irkutsk supplies, both nationally and in Shanghai, are shown in Figure 61 for the four reference scenarios. LNG is a part of the supply mix for the large volume scenario featuring Irkutsk (EFS C1). In that case Irkutsk supply is lower cost than LNG to Shanghai because it benefits from economies of scale due to the larger pipe. However, in the other three reference scenarios (EFS C3, PCS C1 and PCS C3), where LNG is not a part of the supply mix, it is estimated to be lower in cost in Shanghai than remote pipeline supply if it were available.

The LNG estimates in this study show a single figure for the costs of transportation to the various markets. Obviously, actual transportation costs will vary significantly depending on the distance of the specific gas source from market. (Wellhead costs will also differ from source to source, but they, like the costs of downstream gas distribution, have not been included in this study). The single-figure LNG estimates have been made using a standard LNG facility at the 'balance point' of Asia Pacific markets. The 'balance point' is a hypothetical location positioned at the weighted average distance of all existing Asia Pacific contracts from either Guangzhou (Shenzhen) or Shanghai. Because it represents an average distance from market, the 'balance point' LNG calculations will overstate transportation economics from some actual LNG facilities, while it will understate others. Figure 62 illustrates representative transportation costs, both for the balance point as well as from locations in Kalimantan (Indonesia), Australia and the Middle East. Thus while 'average' LNG costs into Shanghai will be lower than pipeline costs in most cases (Figure 62) they will not be lower for some locations, such as the Middle East, for example.

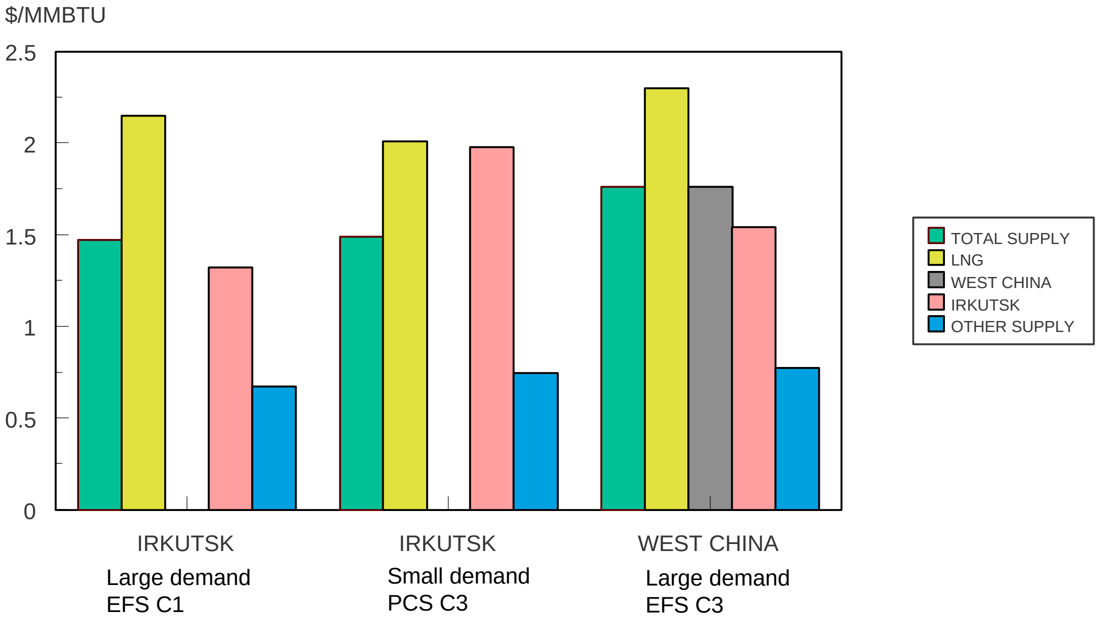
[36] Rate design issues, including a description of mileage, zonal and postage stamp rates, are discussed in Appendix A.

Figure 59 Cost comparison between LNG and pipeline gas from West China or Irkutsk



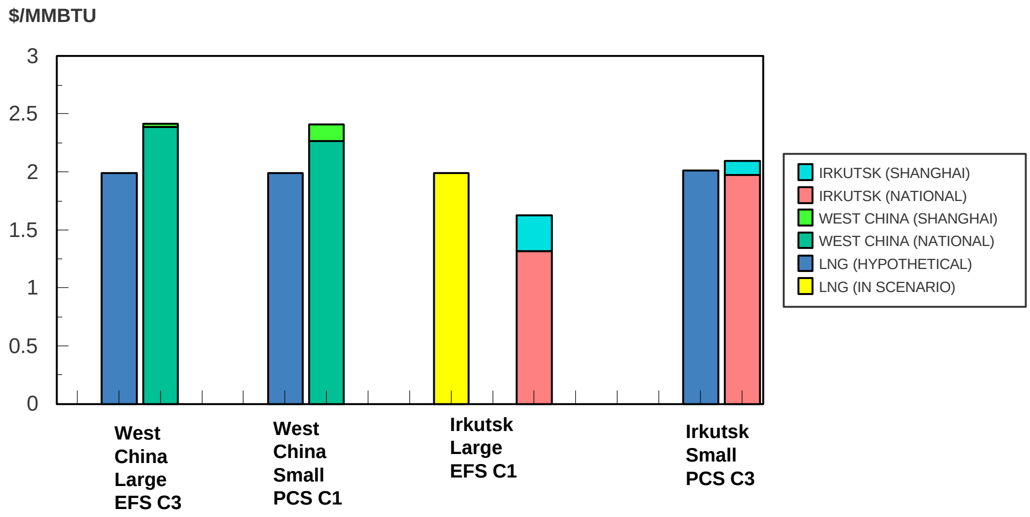
Notes: In the small demand scenarios, using LNG as a sole source of imports is more costly than west China development or Irkutsk

Figure 60 Cost comparison between LNG and pipeline gas (Low cost scenarios)



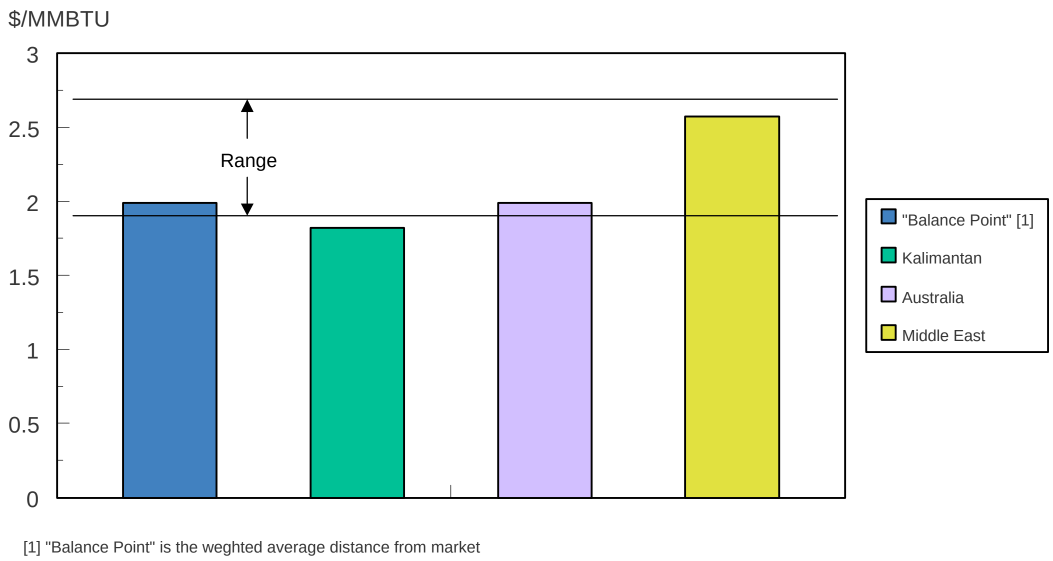
Notes: Lowest cost scenarios without re-exports

Figure 61 Cost comparison between LNG and pipeline gas (Low cost scenarios)



Notes: LNG (If available) would be cheaper in Shanghai than other distant supplies in three of the four low cost scenarios

Figure 62 Cost comparison between LNG and pipeline gas



Notes: Representative costs of LNG transportation to Shanghai "Balance Point" compared with other sources

THE RE-EXPORT OF PIPELINE GAS TO KOREA

The addition of re-export volumes for Korea and Japan lowers the cost of gas supply to China in those scenarios that have been considered in this study. While the added volumes bring in more remote supplies than those on which the reference scenarios have been based, the additional costs are more than offset by economies of scale and the rearrangement of internal supplies to nearby markets. This is illustrated in Figure 63 where the re-export scenarios are compared with the four reference scenarios.

In the large demand scenarios, incorporating gas re-export to Korea (EFS CK1) lowers the costs of the West China option. It would actually raise the costs to China if that economy had elected to import gas from Irkutsk first. While the physical supply for Korea under this scenario would actually come from Irkutsk, the re-export would deprive China of Irkutsk supply that it would normally use under scenario EFS CK1, thereby forcing China to develop more expensive West China supply for itself. In this analysis it has been assumed that China would be able to charge Korea a 'merchant premium' in order to maintain its own supply costs at the same level as EFS C1. In the case of the smaller volume PCS scenarios, the addition of the re-export volumes provides pronounced scale economies for both the West China and Irkutsk scenarios, and the improvement steadily increases with volume.

For Korea, the larger volumes of gas for its own and possibly the Japanese market provide economies of scale for the marine pipeline from the Chinese mainland to Inchon. In those scenarios where Korea is the sole customer for Chinese re-exports, the scale economies are insufficient to make pipeline gas competitive with LNG. However, in those scenarios involving additional re-export to Japan, the additional load on the China/Korea offshore line shifts the cost advantage in favour of pipeline gas over LNG. These patterns are shown in Figure 64.

Figure 63 Scenarios illustrating cost reductions to China from re-export to Korea and Japan

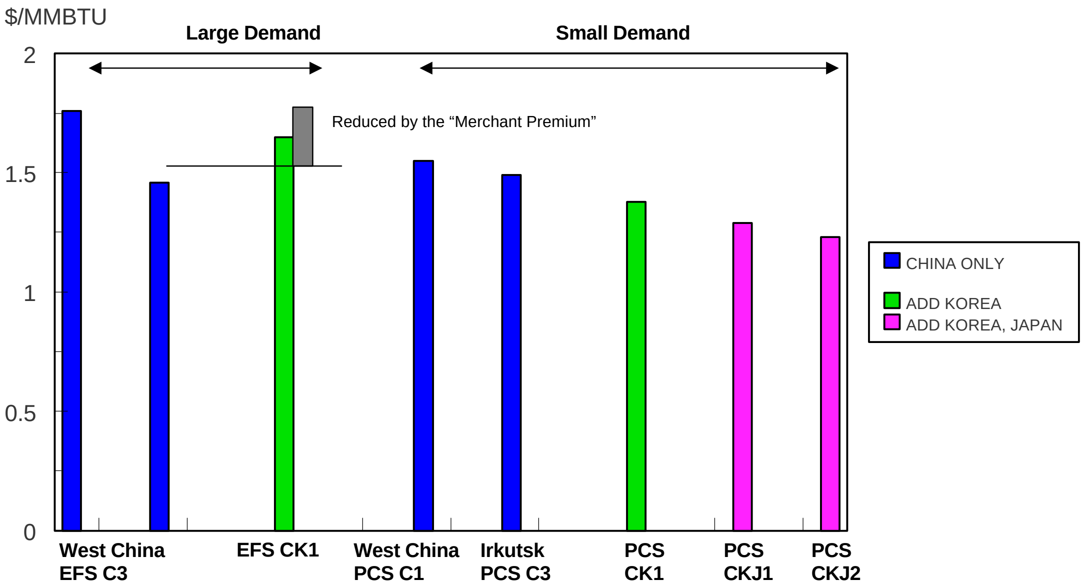
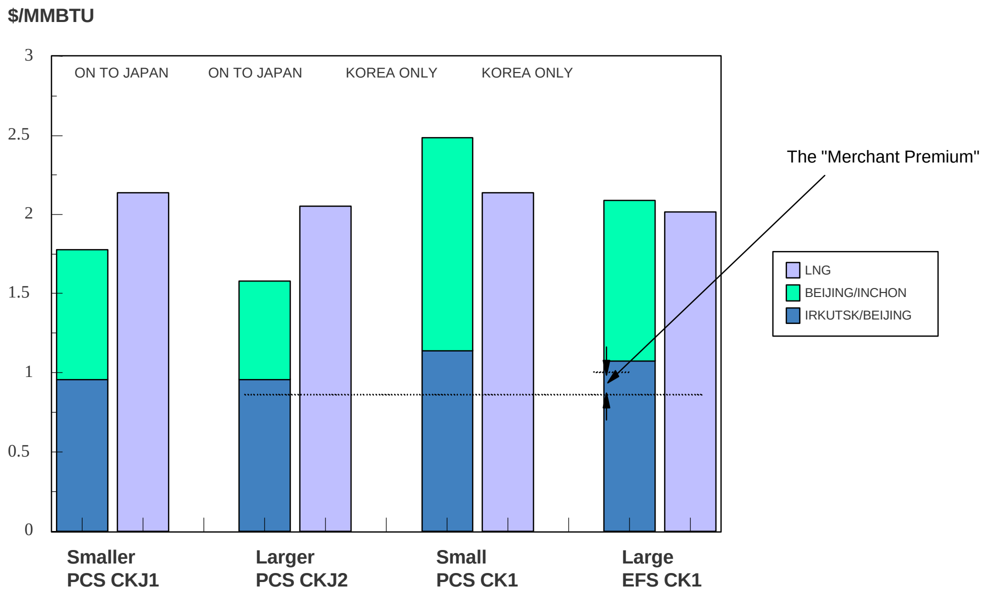


Figure 64 Costs of gas to Korea - LNG versus re-exports from China



CHINESE RE-EXPORT OF PIPELINE GAS - THE TRANSIT FEE ISSUE

Until relatively recently, most international trade in pipeline gas involved economies that bordered on the supplier. Where transit through third countries occurred, the specific cost of the transit was often obscured by the fact that the transiting country often took title to the gas and resold the gas as a merchant. With the growth of international pipeline grids and the move to provide open access to pipeline systems, increasing pressure to break out the transit fee as a transparent transaction has arisen. While there is no 'standard' transaction fee, some planning estimates assume a figure in the range of $0.02 to $0.03 per million Btu per 100 km.

In this study, transit fees for transit through China of gas destined for Korea, or through Korea for gas bound for Japan have not been included. In the analysis it is assumed that pipelines will pay the equivalent of a 25 percent income tax on profits earned in the countries they traverse, which is in itself compensation to the transit economy. And since China and Korea benefit from the development of integrated re-export projects (except for China in the case of the large volume export to Korea, EFS CK1, where a 'merchant premium' is assumed), it is assumed that a separate transit fee can be forgiven as a part of project negotiations.

If a separate transit fee is required, it would raise the costs of re-export to Korea and Japan. In the case of Korea, the transit fee to China, using the assumptions above, would range from $0.45 to $0.75 per million Btu for Korea and $0.50 to $0.85 per million Btu in the case of Japan. Fees of these magnitudes would seriously burden any of the re-export projects.

COMPARING PIPELINE AND LNG SUPPLY FOR JAPAN

Like Korea, Japan has been entirely dependent on LNG for its imported gas supply. But unlike Korea, it lacks an internal pipeline infrastructure that would enable it to receive pipeline gas. Current LNG supplies are consumed either directly at the terminals by electric utilities or distributed to local service areas that are supplied by the gas utility in the region. Hence any consideration of pipeline supply requires the design and construction of what is often referred to as the 'Japanese gas grid'. For purposes of this study, the design of this grid system has been tailored to each specific scenario.

For Korea, the only supply options that this study considered involve re-export from China, but Japan also has the alternative of direct receipt from the Russian Far East in Sakhalin. For the four Japanese scenarios, it is assumed that the principal target market would be the central Honshu regions of Kinki (Osaka), Chubu (Nagoya) and Kanto (Tokyo). The gas via China would land in Japan from Korea at Kita Kyushu in the south while the Sakhalin gas would land at Sapporo in Hokkaido in the north. In addition to the central Honshu regions, the southern landing would enable the pipeline to serve both the island of Kyushu and the southern region of Chugoku, while the Sakhalin gas would also serve Hokkaido and Tohoku in northern Honshu.

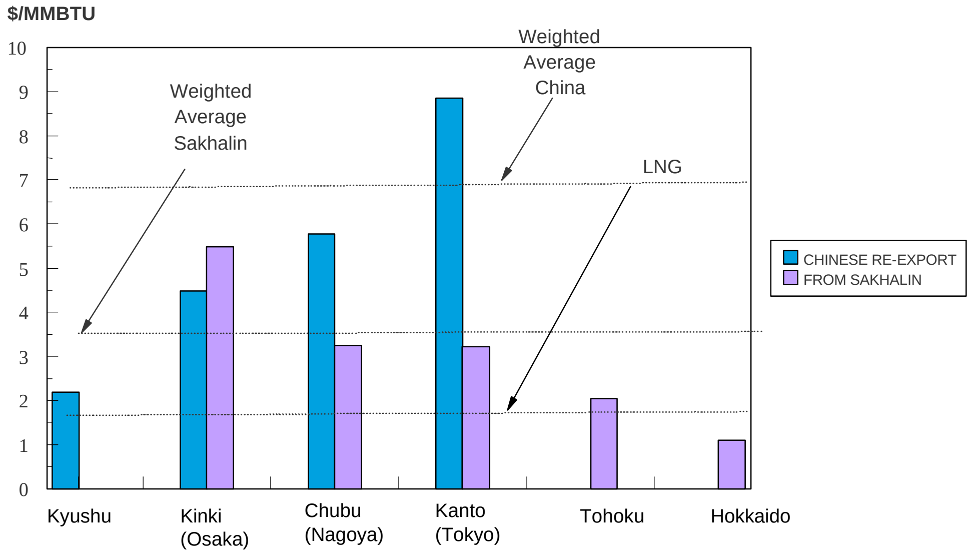
Japanese onshore pipeline construction costs are much higher than typical international levels, making it attractive to place longer-distance trunk pipelines offshore. These can then feed onshore systems destined for major metropolitan areas. For deliveries from Sakhalin, the study assumes offshore construction from Sapporo through Niigata to Tsuruga. In the Chinese re-export scenarios, the route is entirely onshore through the densely populated region between Osaka and Tokyo.

Because of the high construction costs, the cost of pipeline supply to major markets rises very rapidly. For example, the estimated landed cost of pipeline supply, either in Kyushu (from China) or in Hokkaido (from Sakhalin) is equivalent to or lower than the LNG estimates. However, by the time it is delivered to the major central Honshu markets, it is much more expensive. In a tariff design that is distance sensitive (mileage rates or zonal rates), the markets at the greatest distance from the supply source will pay the highest tariffs. Thus Osaka has a significant advantage in a Chinese re-export scenario while Tokyo would see lower costs with a system from Sakhalin.

Figure 65 and Figure 66 illustrate the costs of pipeline gas compared to LNG for both the larger and smaller Japanese scenarios. As is evident from the two diagrams, if the cost of gas delivered to major metropolitan areas is the sole criterion of choice, pipeline gas is non-competitive with LNG. However, if the purpose of introducing pipeline gas is to extend the natural gas delivery system to areas of Japan that are not presently served by gas, or to obtain the benefits of competition with LNG, it must be judged more broadly than as a bulk transportation system, which is the focus of this study.

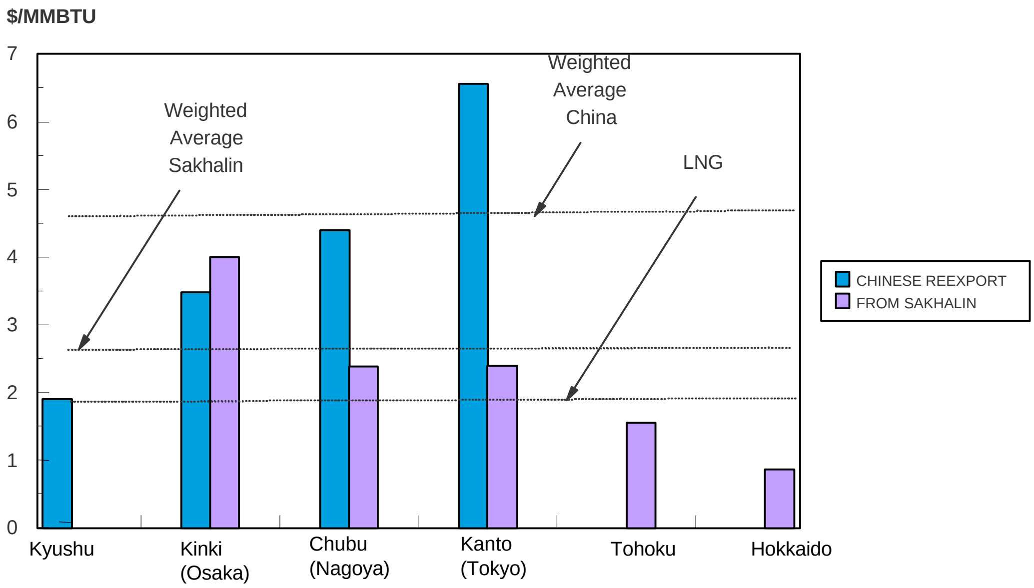
Because of the high costs of pipeline construction in Japan and the influence of economies of scale, it is very difficult to serve small and remote markets competitively. Thus the ultimate cost of the system, as well as the delivered gas, are quite sensitive to the design parameters. Costs can change significantly by altering the markets that the system will serve and by changing the design volumes to be delivered. For example, if the pipeline system were to deliver all of the scenario volumes to a single market (assuming that the market was large enough to absorb them) rather than distributing them throughout Central Honshu, it would reduce the costs significantly. Figure 67 compares the cost estimates of delivering gas from the Chinese and Sakhalin sources as if the total volume could be concentrated into a single market, to the cost of delivering gas to the three major Japanese markets as estimated in scenarios PCS CKJ1 and PCS SJ1. Markets that are at the end of the pipeline system, Tokyo for Chinese deliveries and Osaka for Sakhalin deliveries, would show substantially reduced costs.

Figure 65 Chinese re-export compared with Sakhalin supply for markets in Japan (1)



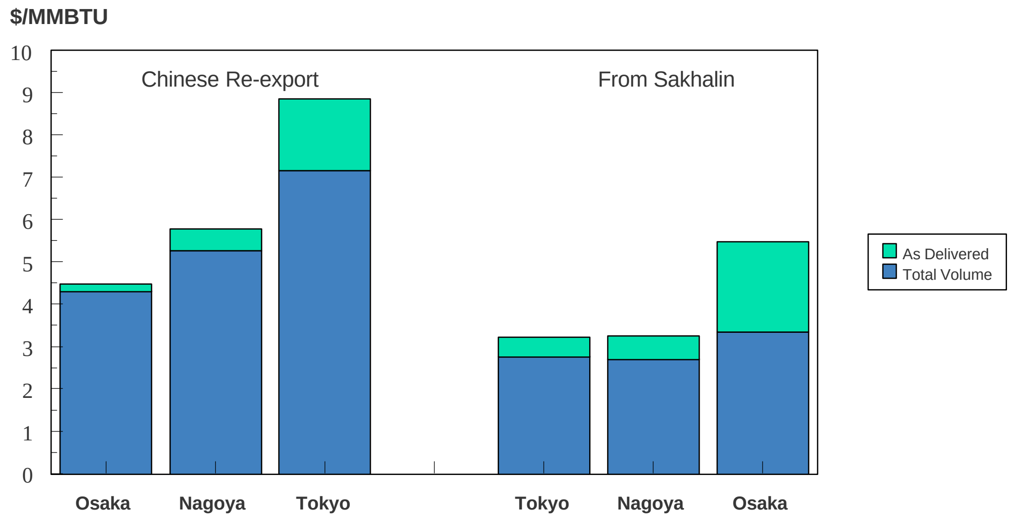
Notes: (1) Smaller demand scenarios PCS CKJ1 & PCS SJ1 (9.36 BCM)

Figure 66 Chinese re-export compared with Sakhalin supply for markets in Japan (2)



Notes: (2) Larger demand scenarios PCS CKJ2 & PCS SJ2 (16.12 BCM)

Figure 67 Effect of economies of scale on delivered gas price



Notes: If it were possible to deliver the total volume to one individual market, scale economies would reduce the delivered costs of gas (PCS CASE)

SUMMARY

- Comparing the transportation cost estimates of importing natural gas by pipeline into China (which consists of the investment and operating costs of pipeline construction), Irkutsk provides the lowest cost source of supply followed by Sakhalin, Turkmenistan, Kazakhstan, and the Trans-ASEAN system, in that order.

- The remoteness of the West China supplies makes them more comparable to imported pipeline supplies than the more accessible domestic gas supplies from the Ordos and Sichuan basins.

- In these scenarios, the estimated pipeline transportation costs associated with supplying China's gas markets from West China are lower than the estimated transportation costs of importing gas by pipeline from the other sources except Irkutsk. The estimated cost of transporting imported gas from Irkutsk is lower than that of West China gas in both the larger (EFS) and smaller (PCS) demand scenarios.

- The estimated cost of transporting LNG into the Changjiang Delta (Shanghai) region is usually lower than the transportation cost estimates of supplies from major remote pipelines. The Changjiang Delta is the market 'anchor' for any large pipeline project from remote areas.

- For Korea, the estimated cost of transporting gas by pipeline is lower than LNG transportation costs in those scenarios involving re-export to Japan, as a result of the economies of scale from a larger pipe. With Korea demands alone, the large volume scenario (EFS CK1), with about 12 BCM of pipeline imports, has a higher estimated transportation cost than LNG although not by a large amount.

In the small volume scenario, the estimated LNG transportation cost is considerably lower than that of pipeline imports.

- In the scenarios involving Japanese imports, the estimated transportation cost of importing LNG is lower than that of pipeline gas in the major centers of Tokyo, Osaka and Nagoya. For pipeline gas from Sakhalin, the landed cost estimate is lower than LNG, but when the cost of the internal gas grid to distribute the gas to major consuming markets is added in, the pipeline transportation cost estimate is higher than that of LNG.

IMPLICATIONS

For Japan, the estimated cost of transporting natural gas from Sakhalin is lower than from Irkutsk (via China and Korea), and in three of the four cases, the landed cost of pipeline supply is less than LNG. However, when the cost of the internal pipeline grid is included in these scenarios, the pipeline system does not appear to be economic. Japan should look for ways of reducing the cost of developing a trunk pipeline system, or alternatively, minimize the need for an internal gas grid by bringing the pipeline supply to one major market, if sufficient demand can be developed in that market. For example, the Sakhalin pipeline could be built to Niigata and connect with an existing pipeline from Niigata to Tokyo. The pipeline gas would then serve the Tokyo market and markets along the path of the pipeline but would not, in this example, extend to the markets south and west of Tokyo.

For Korea, the most economic scenarios involve re-export to Japan, however, as the previous paragraph points out, the cost of building an internal gas grid poses difficulties for Japan. In the two scenarios where the pipeline ends in Korea, the pipeline transportation cost estimates are higher than for LNG delivery, but in the higher volume scenario (EFS CK1 with 12 BCM), the estimated pipeline cost is only slightly higher than LNG. The best pipeline option for Korea thus appears to be a large pipeline from Irkutsk with a large volume delivery to Korea.

The lowest cost scenarios for China include re-export to Korea and Japan, incorporating the largest pipeline from Irkutsk and the largest re-shipments to Korea and Japan (PCS CKJ1 and PCS CKJ2). However, the difficulties associated with re-exporting to Korea and Japan are noted above. The large demand scenario that also involved re-export (EFS CK1) is actually higher cost than the low demand re-export scenarios. This is because Irkutsk is the primary supply source in the low demand re-export scenarios but in the higher volume scenario, the need to bring in additional supplies from West China raises the overall average cost to China.

For scenarios not involving the re-export of gas supplies from China, the scenario that assumes a large pipeline from Irkutsk (EFS C1) has the lowest average transportation cost, but only slightly less than the small volume scenario (PCS C3). While the pipeline delivery costs are lower with the larger pipe, the need for larger volumes of more expensive imported gas keeps the average transportation cost nearly the same.

While LNG is a cheaper option, in terms of transportation costs, for the Changjiang Delta (Shanghai) region in most scenarios, the higher demand in the Changjiang Delta market allows for larger volume, more economic pipeline options to be considered for China as a whole. In the Changjiang Delta region, pipeline transportation costs are most competitive with LNG in those scenarios assuming a large pipeline from Irkutsk but without West China development (EFS C1, PCS CK1, and PCS CKJ1). However, even in the large demand scenarios with West China development, the transportation cost of supplying the Changjiang Delta region from an Irkutsk pipeline (EFS C3) is not greatly different than the cost of transporting LNG to the region (EFS CK1).

Whether or not to develop West China will most likely be a political decision. In a limited market, West China could meet China's gas needs but the estimated cost of transporting the gas is higher than that of Irkutsk (compare PCS C1 and PCS C3). In a larger demand market, West China supplies could be supplemented with a large pipeline from Irkutsk (EFS C3 or EFS CK1).

Each economy has its own unique opportunities and problems. Hopefully, this study will provide insights and information to assist policy makers in decisions regarding energy plans and infrastructure. It must be kept in mind that the costs here are representative; feasibility studies for specific pipelines would, of course, be more detailed and would yield different results than those presented in this study. However, it is believed that the results of this study can help to guide the discussion and future analyses related to pipeline development in East Asia. Further work needs to be done for such pipelines to become a reality, with realistic assessments of the benefits and costs of such large-scale infrastructure development projects.