ASIA PACIFIC ENERGY RESEARCH CENTRE

NATURAL GAS MARKET REFORM IN THE APEC REGION

2003

Published by

Asia Pacific Energy Research Centre
Institute of Energy Economics, Japan
Inui Bldg.-Kachidoki 16F, 1-13-1 Kachidoki
Chuo-ku, Tokyo 104-0054 Japan
Tel: (813) 5144-8551
Fax: (813) 5144-8555
Email: apercadmin@aperc.ieej.or.jp (administration)

APEC#203-RE-01.2
ISBN 4-931482-23-6

Printed in Japan

FOREWORD

Many APEC economies have begun to reform their natural gas markets in recent years in an effort to make them more competitive and limit the costs of gas to consumers. Other economies are considering whether and how they might do so. Consequently, APERC has undertaken a study of natural gas market reform to assess where reform efforts stand, to evaluate the impacts they have had so far, and to suggest ways in which member economies might benefit from further reform.

This is a matter of interest not only to individual economies but to the APEC region as a whole, in which there is a strong interdependence of gas importers and exporters. While market reform may help importing economies deliver gas more cheaply, it may also help exporting economies produce gas more efficiently and expand their gas markets.

This report is published by APERC as an independent study and does not necessarily reflect the views or policies of the APEC Energy Working Group or individual member economies. But we hope that it will serve as a useful basis for discussion and analysis both within and among APEC member economies as gas market reform efforts proceed.

Masaharu Fujitomi
President
Asia Pacific Energy Research Centre

ACKNOWLEDGEMENTS

We would like to thank all of those who contributed to this study, which could not have been successfully completed without the hard work and inspiration of many individuals.

Within APERC, every single researcher assisted the principal author in providing thorough information for the gas market sketches upon which the analysis is based. Kind assistance was also received from APERC administrative staff in the report's publication.

Especially valuable advice and insights were received from several participants in APERC workshops, including Joe Dimasi and Michael Williams of Australia, Glenn Booth of Canada, Wei Lu of China and Dongin Lee of Korea. We would also like to thank members of the APEC Energy Working Group (EWG), APEC Expert Group on Energy Data and Analysis (EGEDA), and APERC Advisory Board, along with numerous government officials, for their stimulating comments and current information.

APERC CONTRIBUTORS

PROJECT LEADER:

Jeffrey Skeer (United States)

PROJECT PARTICIPANTS:

Ahmad Bin Haji Mohamad (Brunei Darussalam)

Iván Jaques (Chile)

Yanjia Wang (China)

I Gusti Suarnaya Sidemen (Indonesia)

Naoko Doi (Japan)

Jeong-Hwan Kim (Korea)

Jaya Singam Rajoo (Malaysia)

Juan Ramón Mota Aguilar (Mexico)

Gary Eng (New Zealand)

Martin Bonou (Papua New Guinea)

Desiderio Añora Fuerte, Jr (Philippines)

Oleg Sinyugin (Russia)

Chung-Yang Lin (Chinese Taipei)

Vichien Tantiwisarn (Thailand)

Binh Nguyen (Viet Nam)

ADMINISTRATIVE SUPPORT

Sutemi Arikawa, Shohei Okano, Sachi Goto, Mizuho Fueta and Chie Koshino.

CONTENTS

LIST OF FIGURES

LIST OF ABBREVIATIONS

Following are a few abbreviations used in this report, most of which are of a technical nature. Abbreviations of most institutions and organisations in APEC economies are defined in the text.

APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
Bcf	billion cubic feet (one thousand Mcf)
Bcm	billion cubic metres (one thousand Mcm)
Btu	British thermal unit
CHP	combined heat and power
GDP	gross domestic product
GJ	gigajoule (one billion joules or one thousand MJ)
GW	gigawatt (one billion watts or one million kW)
GWh	gigawatt hour (one billion watt-hours or one million kWh)
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IPP	independent power producer
kcal	kilocalories
km	kilometres
kW	kilowatt (one thousand watts)
kWh	kilowatt hour (one thousand watt-hours)
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MBtu	million British thermal units
Mcf	million cubic feet
Mcfd	million cubic feet per day
Mcm	million cubic metres (35.3147 Mcf)
MJ	megajoule (one million joules)
Mtoe	million tonnes of oil equivalent
MW	megawatt (one thousand kW)
MWh	megawatt hour (one thousand kWh)
Tcal	teracalories (one billion kcal or 100 toe)
Tcf	trillion cubic feet (one million Mcf)
toe	tonne oil equivalent (ten million kcal or 39.68 MBtu)
TPES	total primary energy supply
TWh	terawatt hour (one trillion watt-hours or one billion kWh)

EXECUTIVE SUMMARY

NATURAL GAS MARKETS IN APEC ECONOMIES TODAY

Natural gas use is expanding rapidly in APEC economies, especially for electric power generation. Consequently, many APEC economies have undertaken or considered reforms to make their gas and power markets more competitive. In rough terms, APEC economies fall into six different groups in terms of the degree of competition in their gas market, the balance between their gas imports and exports, and their incentives for building gas transportation infrastructure:

- *Mature exporters with vertically integrated monopolies* include Brunei Darussalam, Indonesia and Malaysia. These economies have had a single state-owned firm that monopolises gas production and monopolises or dominates gas transportation. Inefficiencies in these firms could be passed on in higher prices to consumers, including electric power producers, who have no alternative suppliers. But in fact, gas prices to consumers have often been set well below export prices.
- *Recent developers with vertically integrated monopolies* include Papua New Guinea, Peru, the Philippines and Viet Nam. These economies have developed facilities for gas production and transportation simultaneously, with long-term contracts to provide gas to power plants or industry to help secure financing for the facilities.
- A *dominant gas supplier with competition at the edges* characterises gas markets in Hong Kong, Mexico, New Zealand and Russia. While these economies allow competing gas suppliers, at least four-fifths of gas supply in each is provided by one firm, which may thus be able to charge non-competitive gas prices to many consumers.
- A *monopoly or dominant supplier with transport pricing issues* characterises the gas markets in Russia and China. In these economies, price regulations may make it difficult for investments in domestic transportation infrastructure to recover their costs plus a reasonable rate of return, which makes it hard to attract such investments.
- *Importers with wholesale competition and single buyers* include Japan, Korea, Singapore, Chinese Taipei and Thailand. A single firm (two in Japan) buys gas from abroad in each region of the economy or for the entire economy. The buyers try to obtain gas from the cheapest sources but may not always pass cost savings to customers.
- *Evolving retail competition and customer choice* characterise gas markets in Australia, Canada, Chile and United States. In these economies, large industrial firms and electricity generators can generally choose from a variety of gas suppliers, and many residential and commercial customers can choose their gas supplier as well. So gas suppliers have to deliver gas at a competitive price in order to get business.

IMPACTS OF NATURAL GAS MARKET REFORM

Several actual or potential impacts of natural gas market reform may be noted:

- Further reform of gas markets in APEC economies could substantially *boost international gas trade* by lowering gas prices and raising gas demand. This would particularly benefit APEC economies with large indigenous gas reserves, such as Indonesia, Malaysia and Mexico, whose gas production could expand significantly.
- Gas market reform may substantially *lower gas prices* to consumers, considering historical price trends in Australia, Canada and the United States as well as major differentials in LNG terminal charges within Northeast Asia. A background condition for lower prices seems to be the presence of many competing producers.

- Deregulation of wellhead gas prices may lead to *increased price volatility* when there are sudden changes in demand or supply conditions. However, experience in North America indicates that price increases tend to elicit supply and demand responses that return prices to normal levels within a relatively brief span of time.
- There are *synergies between reform efforts in APEC economies that import and export gas.* The impact of gas market reform in Asian gas-importing economies, such as Korea, Japan and Chinese Taipei, could be significantly enhanced by gas market reforms in gas-exporting economies like Brunei Darussalam, Indonesia and Malaysia.
- There are *synergies between reform of gas and electricity markets.* Where electricity market reforms have allowed competition from independent power producers, the scope for competition can be substantially enhanced if gas market reforms let IPPs compete on fuel costs as well as capital costs and non-fuel operating costs.

GAS MARKET REFORM OPTIONS

In each type of gas market, there are several potential options for increasing competition:

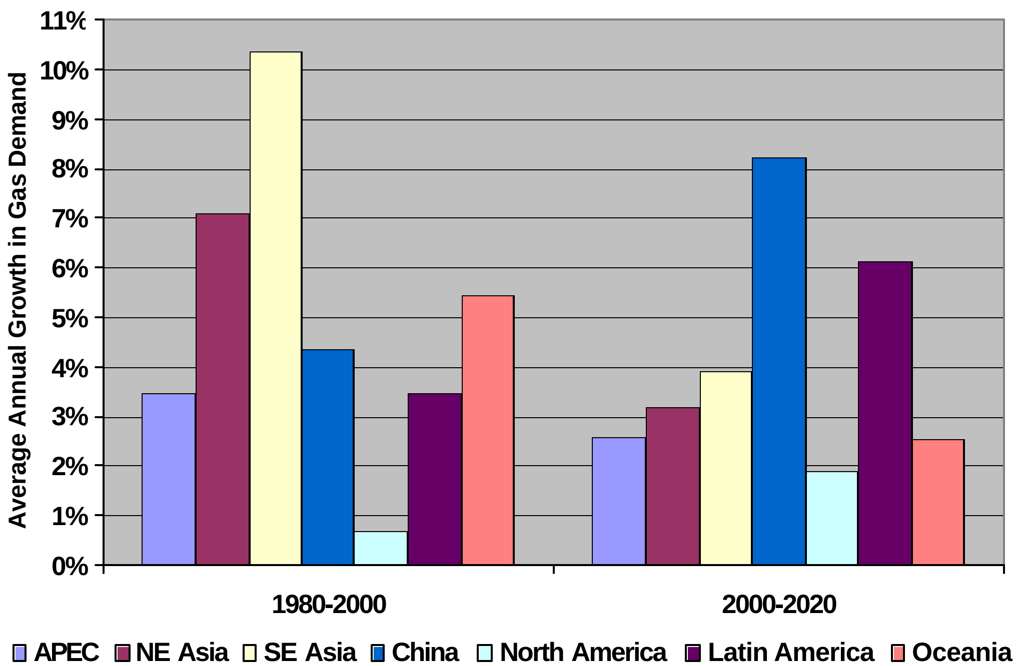
- *Mature exporters with vertically integrated monopolies* could institute a more competitive bidding process for new production sharing contracts and set efficiency targets for existing production sharing contracts. They might also split the monopoly firm into competing firms or divisions and let private firms produce gas on their own.
- *Recent developers with vertically integrated monopolies* could allow competing firms to develop new gas fields and produce gas in fields that have already been opened. They might also give competitors non-discriminatory access to new gas pipelines and capacity on existing pipelines that is not used by incumbent producers.
- Economies with a *dominant gas supplier and competition at the edges* might strengthen requirements for competitive access to gas transportation services. They could also separate transmission and production functions so that the dominant firm no longer has an incentive to discriminate in favour of its own gas production.
- Economies with a *monopoly or dominant supplier with transport pricing issues* might elicit capital for new transportation infrastructure by bringing domestic gas prices in line with market values or costs and eliminating caps on the delivered price of gas.
- *Importers with wholesale competition and single buyers* may wish to increase the flexibility of buyers to respond to opportunities for importing gas at competitive prices. This might involve reduced reliance on long-term contracts, reduced take or pay amounts, and use of the spot market. They could encourage more aggressive price negotiation and lower costs of gas transportation by opening up LNG facilities and pipelines to competitors and allowing customers to choose their gas suppliers.
- Economies with *evolving retail competition and customer choice* might wish to expand the range of customers that are allowed to choose their gas suppliers. They could also encourage customers to switch suppliers by simplifying the process to do so, providing reliable information on competitors' terms and rates, and ensuring that fall-back rates with the traditional utility allow a margin for price competition.

INTRODUCTION

THE SETTING FOR NATURAL GAS MARKET REFORM

Natural gas use in the APEC region is substantial and growing rapidly. Almost every economy in the APEC region already relies on gas for a major share of its primary energy supply. Moreover, the use of gas is expanding rapidly in most economies, particularly for electric power generation. Combined cycle gas turbines provide an economical and highly efficient means of producing electricity with low emissions of atmospheric pollutants and modest emissions of carbon dioxide. As a result, natural gas has often become the fuel of choice for meeting growing electricity needs.

Figure 1 Past and Projected Growth of Natural Gas Use in APEC Regions



Source: APERC (2002a). NE Asia: Japan, Korea, Chinese Taipei, Hong Kong. SE Asia: Brunei, Indonesia, Malaysia, Philippines, Singapore, Thailand, Viet Nam. Latin America: Chile, Mexico, Peru. Oceania: Australia, New Zealand, Papua New Guinea.

In these circumstances, many APEC economies have introduced or considered reforms to make their gas and power markets more competitive. Some economies in which the gas industry has been dominated by vertically integrated monopolies have begun to allow competing producers into the marketplace. Other economies in which a single buyer has bought gas at wholesale in each region are beginning to let larger industrial customers and power generators bypass the traditional buyer and purchase gas directly from producers. Still other economies, with many competing gas producers, are extending supplier choice to small residential and commercial customers as well.

STUDY SCOPE AND OBJECTIVES

Given the growing reliance on natural gas as an energy source and the trend toward reform of natural gas markets, a number of interesting issues have arisen for APEC economy policy makers. What kind of gas markets exist in other APEC economies? What sorts of market reform measures are being taken or considered? Have reform efforts to date been successful in lowering the price of natural gas to electricity generators and to industrial, commercial and residential consumers? What are the interactions between APEC economies that import gas and those that are gas exporters? Could lower gas prices for importers help to boost gas demand and revenues for exporters? How do reform efforts in gas markets affect reform efforts in power markets, and vice versa? What kinds of options for further gas market reform might reasonably be expected to enhance competition and lower gas and power costs in economies with different types of gas markets today?

This study aims to address such issues through a comprehensive analysis of natural gas markets throughout the APEC region. It describes the current structure of the gas market in each major APEC economy, the measures that have been proposed or implemented to make the market more competitive, and the links between gas and power markets in the economy. It then groups economies according to the degree of gas market competition that is present in each, whether they are natural gas importers or exporters, and the incentives offered for building gas transportation infrastructure that makes competition by different gas producers possible. After this, the study assesses the impacts of gas market reform on gas prices, the relationship between reform efforts in importing and exporting economies, and the interaction of reforms in gas and power markets. Finally, the study suggests some options for further gas market reform in each type of gas market.

OUTLINE OF THE REPORT

Following this introduction, the report describes three basic gas market models. Some markets have vertically integrated monopolies, with production and transportation of gas performed by the same company. Other markets have wholesale competition, where a single buyer presumably purchases gas from the cheapest available source. Still other markets have customer choice among competing retail gas suppliers. The basic features of each market type are outlined, with the understanding that actual markets may only roughly approximate any one of the three.

The report then characterises APEC gas markets and classifies them in one of six groups, based upon their gas market model, the balance between their gas exports and imports, and their incentives for construction of transportation infrastructure. Four of the six groups are primarily vertically integrated monopolies. One of these groups consists of mature gas-exporting economies, while a second consists of economies with recently developed gas markets. A third group of vertically integrated gas markets includes economies that have a dominant gas supplier with competition at the margins, while a fourth includes economies with infrastructure pricing issues. The fifth and six groups have gas markets with wholesale competition and customer choice.

In the following chapter, the report examines the actual and potential impacts of reform. It starts by focusing on the potential impacts of reform for APEC gas-exporting economies. It then examines how market reforms have actually affected the price of gas in those APEC economies that have instituted reforms already, as well as how reforms might affect the price of gas in economies where reforms are being considered. Following this, the report shows how the impacts of gas market reform in gas-importing economies are related to reform efforts in gas-exporting economies, as well as how gas market reform may enhance the impacts of power market reform.

The final chapter of the main report offers a number of options for further reform of gas markets that APEC economies might wish to consider. Separate options are suggested that might realistically be expected to enhance competition in each major type of natural gas market.

Following the main body of the report are gas market sketches of each APEC economy. These market sketches serve as the principal background for the report's analysis and conclusions. Each sketch begins with a brief description of the gas market setting in each economy, including the balance between exports and imports, the breakdown of historical and projected demand by end-use sector, and the extent of infrastructure for gas distribution. The gas market structure of each economy is then described, including the principal producers, transporters and distributors of gas, as well as provisions made for the access of competing gas suppliers to gas transportation services. Where data are available, the relationship between gas price trends and reform measures is assessed. The adequacy of financial incentives for natural gas infrastructure is also evaluated where possible.

GAS MARKET MODELS

INTRODUCTION

APEC economies exhibit a broad range of gas market models, reflecting a variety of economic circumstances and levels of development. Some gas markets are essentially monopolistic, with the production and transportation of gas controlled by a single entity. Other gas markets are highly competitive, with many producers vying for customers over a transportation network to which all suppliers may gain access on similar terms. Many gas markets are somewhere between these two extremes, often with a single wholesale buyer choosing among competing producers but with some or all final gas consumers obliged to purchase gas from the monopoly wholesale buyer. This chapter outlines the different market types and their theoretical advantages and drawbacks.

In describing gas markets, it is important to focus on their links with electric power markets. In many economies, a large share of natural gas is used to produce electric power and a large share of electric power is generated from natural gas. The degree of competition in gas markets may affect the ability of power producers to secure gas at competitive prices, which in turn may affect the extent to which gas rather than other fuels is used to generate electricity. Conversely, the degree of competition in electricity markets may affect the extent to which electric power suppliers take advantage of opportunities for competitive procurement of gas and the extent to which efficiency improvements due to gas market reform are passed through to energy consumers.

Broadly speaking, there are three basic types of gas market structure, with substantial variation:

(1) Vertically Integrated Monopoly (single entity controls production and transportation);

(2) Wholesale Competition (transport entity buys gas from competing wholesale suppliers);

(3) Customer Choice (final customers obtain gas from competing retail suppliers).

VERTICALLY INTEGRATED MONOPOLY MODEL

CHARACTERISTICS

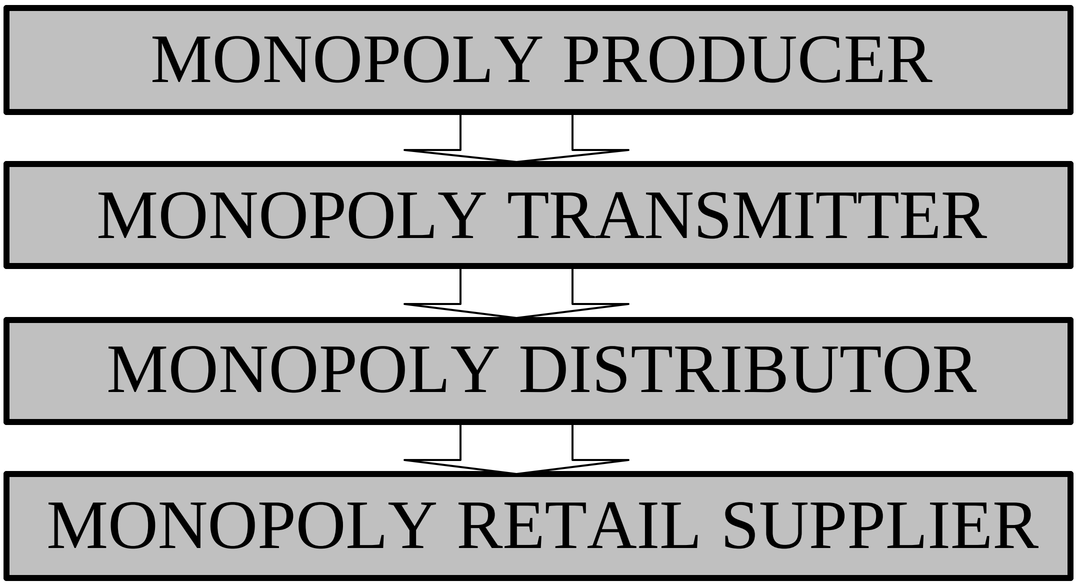
In the vertically integrated monopoly model, a single entity produces gas, transmits it to consuming areas, and distributes it locally. The entity may be the government itself, operating through one or more state-owned firms, or a private firm or consortium with a government license. It may be integrated horizontally as well as vertically, with an economy-wide franchise for gas delivery. In economies with greater geographic extent, there may be more than one vertically integrated monopoly, each with its own geographic service territory. Alternatively, there may be a single entity that produces and transmits gas, from which separate entities, each with a monopoly franchise in a different geographic service territory, purchase gas for distribution to consumers.

If a vertically integrated monopoly controls both production and transportation of gas, there is rarely wholesale competition among producers. In theory, the monopoly might buy some gas from producers abroad if its own supplies were extremely expensive or inadequate to serve demand. But the monopoly will ensure that all of its own production is transported and sold before that of any foreign competitor. In gas-exporting economies, where production is more than adequate to meet demand, competitive wholesale procurement by the monopoly is especially unlikely.

At the same time, regardless of whether the distribution function is economy-wide or divided among several geographic franchises, a vertically integrated monopoly provides no opportunity for retail competition among suppliers to final customers. Large industrial firms and electricity generators, who can buy gas directly from the transmission network, have but one production-transmission entity from which to buy. Smaller customers, who must obtain their gas over a local distribution grid, are obliged to buy their gas from the single distributor in their area.

Insofar as economies are net gas importers, a vertically integrated monopoly is unlikely to prevail. In economies that import all or most of their gas, whether by pipeline or through LNG facilities, production must occur primarily in the countries from which gas is imported. It follows that production and transport of gas cannot be vertically integrated within the importing economy. Where a relatively small share of gas needs is imported, there may still be substantial integration of supply and transport within the importing economy. In such cases, the vertically integrated monopoly can minimise its costs by procuring gas imports from competing suppliers abroad. But since the monopoly has no internal competitors, it may not take full advantage of this opportunity.

Figure 2 Vertically Integrated Monopoly Model



ADVANTAGES AND DISADVANTAGES

Particularly in economies where gas markets are at an early stage of development, the integration of production and transport may make it easier to obtain capital for new gas projects. For example, it may be possible to identify a large industrial or power industry customer to absorb all or most of the gas from a newly discovered gas field. In such a case, the gas production facilities and associated pipelines may be easier to finance because there is an identified revenue stream. Meanwhile, the factories or powerplants using the gas may be easier to finance because they have a clearly identified fuel source under a price formula that is specified by contract.

The most obvious disadvantage of the vertically integrated monopoly model is that there is little incentive for the monopoly to minimise costs. Without competitors, productive inefficiencies can go unchecked, raising costs substantially. Where the monopoly is government-owned, there may be political pressure to retain staff in excess of what is technically required to produce and transport gas. Because there is only a single gas supplier, excess costs arising from productive inefficiencies can be readily passed on to consumers, who have nowhere else to turn for their gas. Alternatively, the government may decide to set domestic gas prices below gas prices in export markets, resulting in lost state revenues from abroad and inefficient gas use at home.

Without proper regulation, a private vertically integrated monopoly tends to restrict gas output and raise gas prices above the cost of production (including the cost of capital). In this case, some potential gas customers will be compelled to use other fuels instead, so gas demand and markets will not develop to the extent that they would in a competitive environment. Such allocative inefficiency may have major costs to the economy if alternatives to gas are much more expensive. If the alternative fuels are imported, there will also be a deleterious impact on the balance of trade.

POWER MARKET LINKAGES

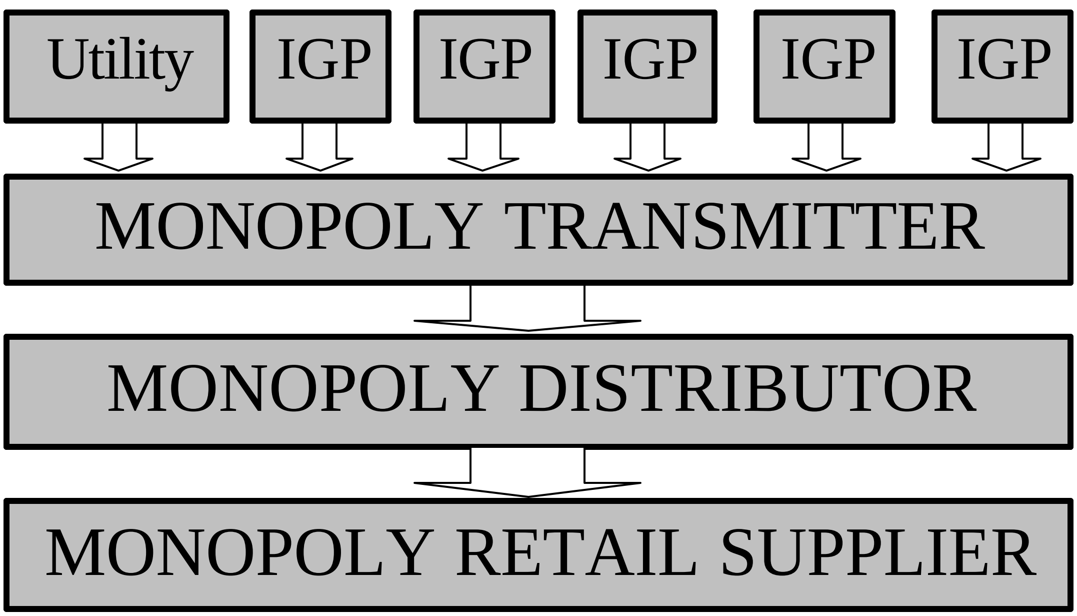
Where the gas market has a vertically integrated monopoly, the electric power market may also have a vertically integrated monopoly or may have wholesale competition with a single buyer. Potential problems of productive and allocative inefficiency will then be present in both markets. Insofar as the electric power monopoly or single buyer depends on gas-fuelled generation, elevated gas prices that result from inefficiencies in the gas market can be passed on to electricity consumers in the form of higher electricity rates. Since consumers have only one power source and electricity has no substitutes in many uses, the power monopoly or single buyer can absorb higher gas prices in rates with little damage to profits. Alternatively, if the power monopoly or single buyer gets a subsidised price from the gas monopoly, it may pass on less than the full cost savings to consumers.

WHOLESALE COMPETITION MODEL

CHARACTERISTICS

In the wholesale competition model, competing entities produce gas but each geographic area has a single entity that buys and transmits gas and a single entity that distributes gas to consumers. There may be a single buyer that purchases, transmits and distributes gas throughout the economy. Alternatively, there may be regional buyers that purchase, transmit and distribute gas in different geographic service territories. Or a single buyer may purchase and transmit gas throughout the economy while regional distributors with franchised service territories sell gas to final consumers.

Figure 3 Wholesale Competition (Single Buyer) Model



The extent of wholesale competition may vary according to several factors. One key factor is the adequacy of transportation infrastructure. Where there is plenty of capacity in pipelines and LNG terminals, there is room for many different foreign or domestic producers to compete. Where capacity is constrained, the space for competition may likewise be limited. Another key factor affecting wholesale competition is the buyer's corporate structure. Where the buyer is organised for profit, there will be gains to both public and private shareholders from keeping costs down and a corresponding incentive to procure gas from the least-cost suppliers. Where the buyer is not organised for profit, the incentive to buy gas from the least-cost competitor may be weak.

Because the distributor of gas in each area is also the sole gas retailer in that area, the wholesale competition model does not allow retail competition among suppliers to final customers. Just as in the case of a vertically integrated monopoly, large industrial firms and power generators who take gas directly from the transmission grid have only one entity from which to buy. And smaller customers, who obtain gas from a local distribution grid, must buy from the single distributor in their area.

ADVANTAGES AND DISADVANTAGES

The main advantage of the wholesale competition model is that there is an opportunity to limit costs by procuring gas from the least-cost producers. Knowing that the buyer has a choice among many competitors, each producer will have an incentive to offer the buyer an attractive price. The buyer can then choose the least-cost sources of supply, which are presumably those that can produce and deliver gas to the economy most efficiently. As indicated above, this advantage may accrue to the extent that transportation infrastructure can accommodate different suppliers and insofar as buyers are organised for profit with an incentive to keep costs down.

The clearest disadvantage of the wholesale competition model is that there is little pressure from consumers for the single buyer of gas and the single distributor of gas to minimise costs. Where the buyer and distributor are organised for profit, they will have an incentive to procure gas from the least-cost suppliers, to ensure that pipelines and LNG facilities are adequate to accommodate competing suppliers, and to operate transmission and distribution infrastructure in an efficient manner. But the quality of management may vary, and the single buyer and distributor of gas in each area may have varying degrees of success in keeping costs down. With only a single supplier in each area, excess costs from productive inefficiencies can be passed on to consumers. Unless the cost of gas becomes so high that consumers turn to alternative fuels, the supplier's excess costs and inefficiencies will remain in place unchecked by competition.

POWER MARKET LINKAGES

Where natural gas is a major fuel for electricity generation, having only a single supplier of gas is likely to limit efficiency or impede competition in the electric power market. If there is also only a single supplier of electricity, any inefficiencies on the part of the gas producer or supplier can be readily absorbed by the single electricity supplier and passed on to consumers in electricity rates, so there is little market pressure for the inefficiencies to be addressed. If the electricity market should happen to be open to competition, both traditional electric utilities and independent power producers will be obliged to purchase gas from the same supplier, probably at about the same cost. In this case, it will be relatively difficult for IPPs to undercut utility supply costs and compete.

TRANSITIONAL ISSUES

Economies wishing to move from the vertically integrated monopoly model toward the wholesale competition model would need to separate the gas production from gas transmission and distribution. This might involve the sale of gas production facilities to one or more competitors, with monopolies remaining in control of transmission and distribution. Key issues would then include the period over which production assets are to be divested, the bidding system by which prices for the assets are set, and the number of different entities to which production facilities are sold to ensure competition among producers when divestiture is complete.

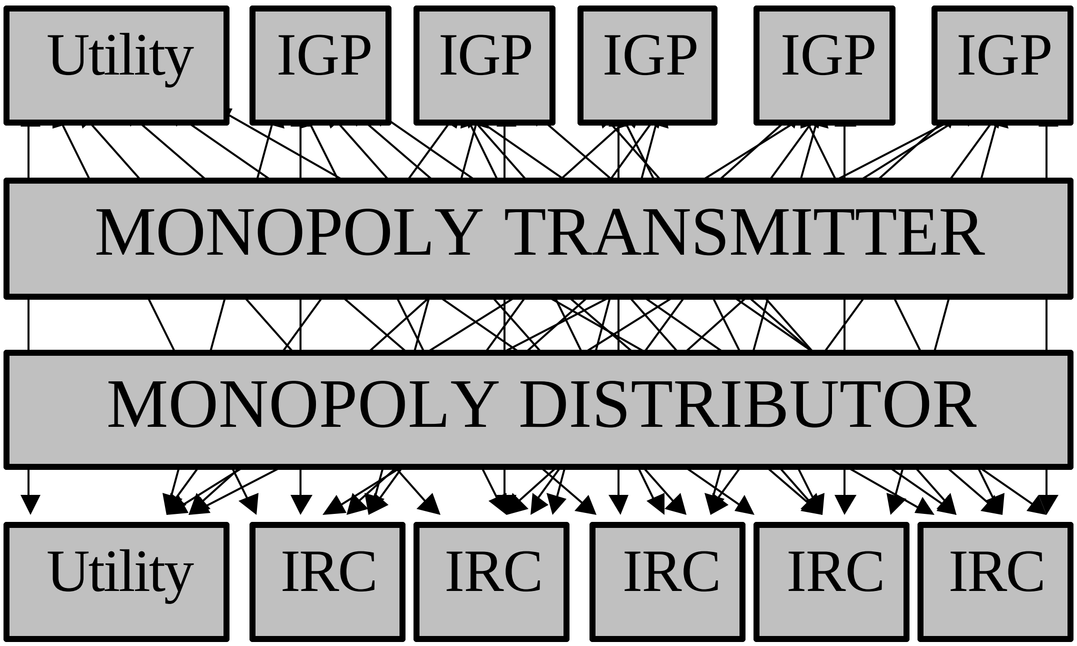
CUSTOMER CHOICE MODEL

CHARACTERISTICS

In the customer choice model, competing entities produce gas and supply gas to consumers. Typically, since the gas pipeline network is a natural monopoly that would be wasteful to duplicate, the network in each area is controlled by a single regulated gas transmission company and a single regulated distribution company, although several entities may compete to transport gas through

LNG facilities. But competing producers and suppliers have equal access to pipelines and LNG facilities, on non-discriminatory terms. Customers can therefore shop among competing gas suppliers and select the one that provides gas at lowest cost.

Figure 4 Customer Choice (Retail Competition) Model



The degree to which customer choice is provided may vary. Particularly in the earlier stages of reform efforts, retail choice of suppliers may be limited to large industrial firms and electric utilities, which can obtain gas directly from high-pressure pipelines and LNG terminals. At later stages of reform, retail choice may be extended to small residential and commercial customers who receive their gas over distribution networks. Where transmission and distribution are regulated by separate entities, competing suppliers may first gain access to regional transmission grids and large customers, only later gaining access to local distribution grids and small customers.

Customer choice is best provided if transmission and distribution are unbundled from production and retail supply. Monopoly transmission and distribution services need to be regulated to ensure that they are fairly priced and equally available to all competing suppliers. If a monopoly transmission or distribution entity also controls a significant share of production or supply, it will have incentives to discriminate against competing producers or suppliers in determining who gains access to pipelines and LNG terminals, even if the law requires that access be provided on equal terms to all. In this case, it is relatively difficult for regulators to ensure that access to transport infrastructure is non-discriminatory, and a large regulatory staff will probably be needed to do so.

On the other hand, if (regulated) gas transmission and distribution services are controlled independently of (competitive) gas production and supply, ensuring fair access to these services is much easier, and the regulatory task is simplified. If independent entities control transmission and distribution, they will have no reason to discriminate in favour of one producer or supplier over another. Hence, infractions of laws requiring non-discriminatory access to these services will be relatively rare, and a small regulatory staff will probably be adequate to deal with them.

The regulatory task will be simplified insofar as the separation, or unbundling, of transmission and distribution services from production and supply is complete. With separation of *accounts*, the weakest form of unbundling, the transmission and distribution divisions of a company may still communicate with the production and supply divisions, so discrimination is still quite possible. With *functional* separation, information firewalls are established between the various divisions, so the opportunity for discrimination is diminished insofar as the firewalls are effective. With *operational* separation, an independent entity operates LNG terminals and gas pipelines, so fair access to these facilities should be assured even if they continue to be owned by gas producers or suppliers. With *ownership* separation, no transmitter or distributor of gas may also produce or supply gas, so there is an added degree of assurance that competing producers and suppliers will be treated on a level playing field.

ADVANTAGES AND DISAD VANTAGES

The customer choice model provides the greatest possible assurance that gas will be supplied in the most efficient way, at the least possible cost, to those that have the greatest need for it. Buyers and sellers are directly linked. Efficient producers will gain market share form inefficient producers because efficient producers can provide gas at a lower price and attract more customers. Producers thus have clear profit incentives to address their inefficiencies, and sufficiently inefficient producers will eventually find themselves without business and knocked out of the marketplace.

However, a fully competitive marketplace for gas, like that for any commodity, may result in price volatility from time to time. Particularly if demand is growing rapidly, there may be a period of high prices until new supply can be put in place to meet the increased demand. After production is increased or new infrastructure is built to meet the demand, prices will decline once again. On the other hand, there are market tools, such as futures contracts that provide the right to purchase gas at a fixed price, that market participants can use to limit their exposure to price volatility.

POWER MARKET LINKAGES

Customer choice and competitive supply in the gas industry are likely to have economic benefits in the electric power industry, particularly insofar as the power industry is also competitive. If electric power is supplied by an integrated monopoly, regulators may compel it to shop for less costly gas supplies and to pass on resulting savings to electricity consumers, but to the extent that cost savings must be passed through, incentives to shop around will be weak. If power is provided by a single buyer, with wholesale competition among various electricity generators, the incentives to buy gas cheaply will be greater, since failure by generators to do so could result in unsuccessful bids to provide power to the buyer; and a portion of the resulting cost savings may again be passed on to consumers. If the power sector has customer choice like the gas sector, there will be further pressure to minimise generating costs by purchasing gas from the least-cost suppliers, as high-cost generators may ultimately find themselves without customers and out of business.

TRANSITIONAL ISSUES

Economies wishing to move from the wholesale competition model to the customer choice model will need to separate the retail supply of gas from gas transmission and distribution. They will also need to put laws and regulations in place to ensure that competing producers and suppliers can obtain access to the transmission and distribution grids on equal terms. A key issue is the form that unbundling should take and the corresponding design of the regulatory apparatus. In moving from functional unbundling to operational or ownership unbundling, the economy may reduce the size and complexity of the regulatory apparatus needed to ensure effective competition.

Another important issue in moving to the customer choice model is the extent to which smaller gas customers are allowed and encouraged to participate in the market. Large industrial and power industry customers will generally have a profit motive to shop around for the lowest-cost gas suppliers. Smaller customers, however, may be reluctant to leave the traditional supplier that has served them reliably for many years, even if competitors can supply gas at lower cost. Smaller residential and commercial customers can be encouraged to choose suppliers by making the process of switching suppliers simple, as well as by providing information that makes it easier to compare the price and service offered by different suppliers. Supplier choice by smaller customers will also be encouraged, when building popular support for reform, if the guaranteed "fall-back" rate charged by the traditional supplier is not reduced so far that it is hard for competitors to beat.

GAS MARKET CHARACTERISATION

INTRODUCTION

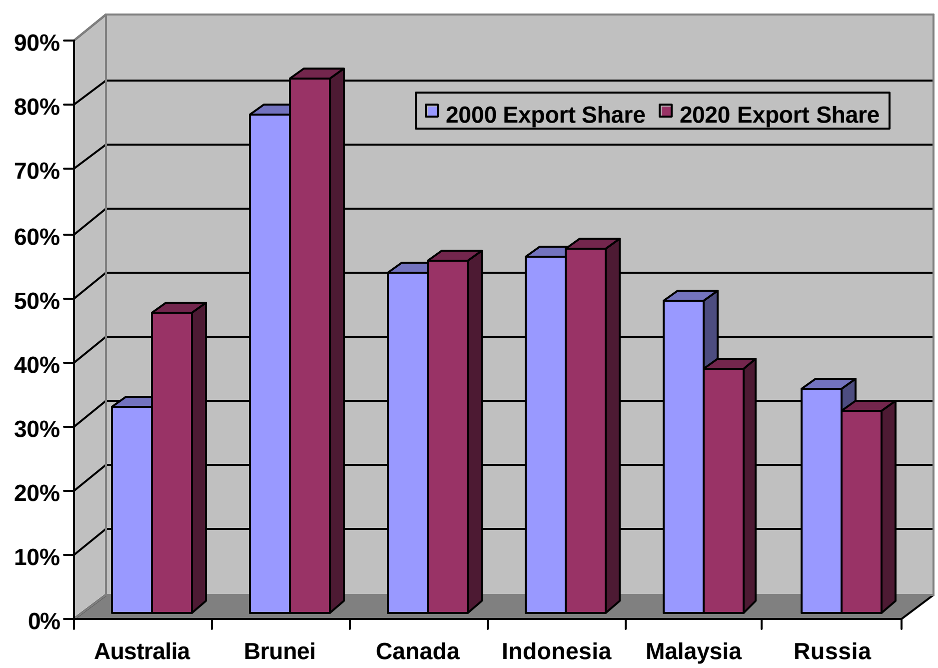
Gas markets in APEC economies vary not only according to their market model, but also according to objective circumstances like whether they are net gas importers or exporters and whether their gas is available just to large customers or also to smaller customers. Such objective circumstances may in fact influence the market model chosen and the way in which the model is implemented. This chapter therefore characterises various economies according to their degree of self-sufficiency in gas supply and the extent of their infrastructure for gas transportation and distribution, as well as their current and anticipated gas market model. The information here is drawn from the gas market sketches of each economy that appear later in this report.

DEGREE OF SELF-SUFFICIENCY IN GAS SUPPLY

GAS EXPORTING ECONOMIES

Several APEC economies are major natural gas producers and exporters. These include Australia, Brunei Darussalam, Canada, Indonesia, Malaysia and Russia. Some of these economies import small amounts of gas, but all are substantial gas exporters on a net basis, and all derive substantial revenues from their gas production. According to APERC projections, as shown below, all major net gas exporters in 2000 will still be major gas exporters in 2020.

Figure 5 Export Share of Gas Production in Selected APEC Economies



Source: APERC (2002a) and internal energy balance tables

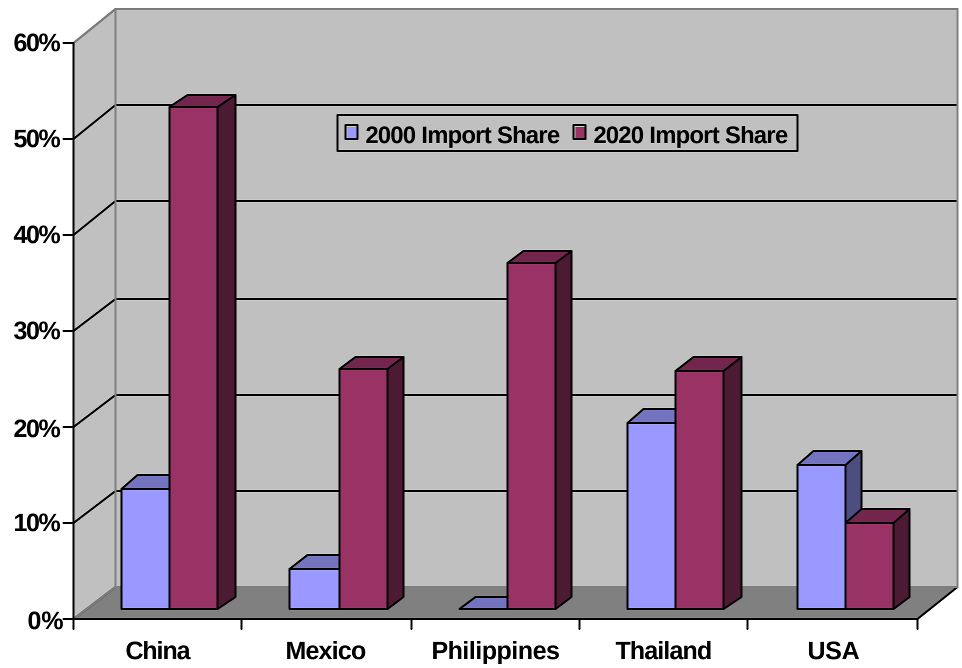
ECONOMIES WITH SELF-SUFFICIENT GAS SUPPLY

Another group of APEC economies is completely self sufficient in gas supply. Most of these are smaller economies with limited gas production and limited demand. They may have some prospects for gas exports, but gas production is expected to remain focused on domestic needs in most cases. These economies include New Zealand, Papua New Guinea, Peru and Viet Nam.

ECONOMIES WITH SUBSTANTIAL DOMESTIC GAS SUPPLY

A third group of APEC economies have significant gas resources and supply most of their gas from domestic production but also import significant amounts of gas from neighbours or are soon likely to do so. These include China, Mexico, the Philippines, Thailand, and the United States. According to APERC projections, as shown below, reliance on natural gas imports will increase substantially in China, Mexico and the Philippines over the next two decades.

Figure 6 Import Share of Gas Supply in Selected APEC Economies



Source: APERC (2002a) and internal energy balance tables

GAS IMPORTING ECONOMIES

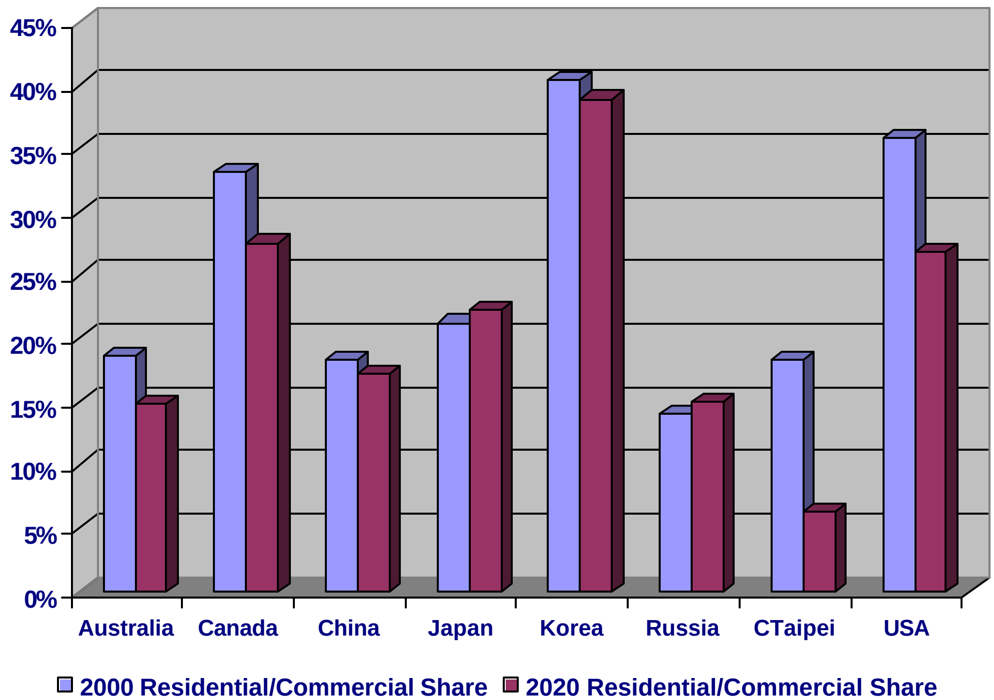
The remaining APEC economies may be characterised as highly import-reliant. These include Chile, Hong Kong, Japan, Korea, Singapore and Chinese Taipei. Each of these economies is projected by APERC to import 95 percent or more of its primary gas requirements in 2020.

GAS DISTRIBUTION GRID DEVELOPMENT

ECONOMIES WITH A WELL-DEVELOPED DISTRIBUTION GRID

Several APEC economies have a well-developed gas distribution grid, as evidenced by a high share of smaller residential and commercial customers in final gas demand. These include Australia, Canada, China, Japan, Korea, Russia, Chinese Taipei and the United States. In each of these economies, the residential and commercial sectors account for at least 15 percent of the current or projected gas market. In China and Russia, however, demand is less diversified than in the other economies in this group; there is substantial residential gas demand but very little gas demand in the commercial sector. Figure 7 indicates the combined residential and commercial share of total gas demand in each of these economies in 2000 and 2020, according to APERC data and projections.

Figure 7 Residential and Commercial Share of Gas Use in APEC Economies with Extensive Natural Gas Distribution Infrastructure



Source: APERC (2002a) and internal energy balance tables

ECONOMIES WITH A PARTIALLY DEVELOPED DISTRIBUTION GRID

A second group of APEC economies have a partially developed gas distribution grid, as evidenced by a lower share of residential and commercial customers in final gas demand. These include Chile, Mexico, New Zealand and Peru. In these economies, distribution grids make gas available to small customers in at least some major urban areas, but not everywhere. The distribution grid is projected to expand substantially in New Zealand, with the combined residential and commercial share of demand projected to nearly double from 6 percent in 2000 to 11 percent in 2020. In the other economies of this group, however, the combined commercial and residential share of demand is projected to remain below 5 percent for the foreseeable future.

ECONOMIES WITHOUT A NATURAL GAS DISTRIBUTION GRID

A third group of APEC economies has little or no gas distribution infrastructure. Natural gas demand in these economies is dominated by industrial firms, including energy producers. Several of these economies might be categorised as "electro-industrial" including Hong Kong, Papua New Guinea, the Philippines and Singapore. In these economies, with limited oil or gas production, a substantial amount of natural gas is used for electricity production, and the combined share of industrial and electric gas demand is greater than 99 percent. However, Hong Kong and Singapore have extensive grids for distribution of town gas manufactured from oil, and Singapore's grid is to be converted to carry natural gas. Other economies in this group might be categorised as more broadly "energy-industrial" including Brunei, Indonesia, Malaysia, Thailand and Viet Nam. In these economies, a large share of the gas is used by oil and gas producers, and the combined share of industrial, electric and "other" (mostly energy-industry) gas demand is greater than 99 percent.

CURRENT NATURAL GAS MARKET MODELS

Gas markets in APEC economies may be classified into six groups, as shown in the box:

GAS MARKET MODELS IN APEC ECONOMIES

Mature Exporters with Vertically Integrated Monopolies

Brunei Darussalam, Indonesia, Malaysia

Recent Developers with Vertically Integrated Monopolies

Papua New Guinea, Peru, Philippines, Viet Nam

Dominant Supplier with Competition at the Edges

Hong Kong, Mexico, New Zealand, Russia

Monopoly or Dominant Supplier with Transport Pricing Issues

China, Russia

Importers with Wholesale Competition and Single Buyers

Japan, Korea, Singapore, Chinese Taipei, Thailand

Evolving Retail Competition and Customer Choice

Australia, Canada, Chile, United States

ECONOMIES WITH VERTICALLY INTEGRATED GAS MONOPOLIES

More than half of the APEC economies (12 out of 21) have gas markets that function mainly or entirely as vertically integrated monopolies. These include economies as varied as Brunei Darussalam, China, Hong Kong, Indonesia, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, the Philippines, Russia, and Viet Nam. Of these economies, almost all are self-sufficient in gas (China, New Zealand, Papua New Guinea, Peru, Philippines, Viet Nam) or net gas exporters (Brunei Darussalam, Indonesia, Malaysia, Russia); there are only two exceptions (Hong Kong, Mexico). In addition, very few of these economies have a well-developed gas distribution grid.

However, conditions in APEC economies with gas markets that function as vertically integrated monopolies are not altogether analogous. Some economies have a very substantial gas-producing apparatus and have been exporting large amounts of gas for decades. Other economies have much more limited gas reserves and have only started producing gas recently. Quite a few economies have state-owned monopolies whose status is enshrined in constitution or law. Others do not have official monopolies but still have firms that clearly dominate so that competition is significantly constrained. Most economies have regulations that ensure an adequate return on investments in gas transportation infrastructure, but there are a couple of notable exceptions.

Because of such distinctions, it is convenient to divide the economies with gas markets that function as vertically integrated monopolies into four groups, each of which is described and analysed separately to account for its particular characteristics:

- Mature Exporters with Vertically Integrated Monopolies
- Recent Developers with Vertically Integrated Monopolies
- Dominant Supplier with Competition at the Edges
- Monopoly or Dominant Supplier with Transport Pricing Issues

MATURE EXPORTERS WITH VERTICALLY INTEGRATED MONOPOLIES

Brunei Darussalam, Indonesia and Malaysia may be described as mature gas exporters with vertically integrated monopolies in their internal gas markets. Each of these economies is a major source of gas supplies for one or more other economies in APEC, and together they dominate gas supply in Japan, Korea, Singapore, and Chinese Taipei. Brunei Darussalam has been exporting gas since 1972, Indonesia since 1977, and Malaysia since 1983. The internal gas market in each of these economies is dominated by a single state-controlled firm that produces gas and transports it to local users. The dominant firm produces all the gas in Indonesia and Malaysia and 90 percent of the gas in Brunei Darussalam. All gas transmission over high-pressure pipelines is controlled by the dominant firm in Brunei Darussalam and Malaysia, while the function is shared with another government-controlled firm in Indonesia.

Each of the mature gas exporters with a vertically integrated internal gas market is also characterised by vertical integration between its internal gas and electricity markets. In each case, a large share of electricity is generated from gas, and electricity generators can only purchase gas from the state-owned gas supplier. Gas fuels very nearly all electricity production in Brunei Darussalam and more than three quarters in Malaysia, while providing about three-eighths of the electric generating capacity in Indonesia. Thus, inefficiencies in gas production or transportation could be readily passed on to power producers, who have no alternative supplier of gas and little flexibility to shift to other fuels. But in fact, gas prices to power producers in these economies are held substantially below gas export prices. In Brunei Darussalam, where all power is produced and transported by a government agency, it is not clear whether all the savings are passed on to electricity consumers. In Indonesia and Malaysia, there is real wholesale competition in the power sector, with 9 percent of generating capacity owned by independent power producers (IPPs) in the former and 43 percent of electricity generated by IPPs in the latter. But because all the IPPs must purchase gas from the same source, the effective scope for competition among them is limited to capital and non-fuel operating costs. And since there is just a single buyer in the power sector, there is no guarantee that fuel price cost savings will be passed on to power consumers.

The potential for inefficiencies in production of gas is limited, in mature gas exporting economies, through the mechanism of production sharing contracts (PSCs). Various international oil and gas companies have competed for roles in existing PSCs, and several different companies are operating in each of these economies. However, since each PSC provides a defined share of production revenues at a given gas field over a long period of time, in return for production activity over that period of time, there is limited assurance that cooperating companies will not develop inefficiencies in the course of their contracts.

Among the mature exporters, it should be observed, Indonesia has recently taken significant steps toward opening up its gas market to wholesale competition. Pursuant to the Law Concerning Oil and Natural Gas of 2001, the state-owned integrated monopoly, Pertamina, no longer has to be included in production sharing contracts as of late 2003. With respect to new gas field developments and expiring contracts at existing developments, the various gas companies operating in Indonesia will be free to operate as independent producers or consortia. Insofar as the share of competitive gas production in Indonesia grows, so will competition in the economy's gas market.

RECENT DEVELOPERS WITH VERTICALLY INTEGRATED MONOPOLIES

Papua New Guinea, Peru, the Philippines and Viet Nam may be described as small or recent gas developers with vertically integrated gas monopolies. Each of these economies is self-sufficient in gas supply, but none yet produces a very large amount of gas, and none is a gas exporter. The Philippines have been producing gas in commercial quantities only since 2001, and Papua New Guinea only since 1992. Viet Nam has been producing some gas since 1981, and Peru since at least the early 1970s, but their production has jumped substantially since the mid-1990s. The gas market in each of these economies is characterised by a single firm that produces and transports gas. In addition, all or most of the gas is used by large industrial firms or power generators that have signed long-term contracts for the gas in conjunction with development of gas supply facilities.

Most of the recent gas developers with vertically integrated gas market have a significant degree of vertical integration between their internal gas and electricity markets. In each case, electricity generators can only purchase gas from the state-owned gas supplier. However, the extent of integration varies with the proportion of power generated from gas, which is high at 58 percent in PNG and substantial at 16 percent in the Philippines and 18 percent in Viet Nam, but a much lower 4 percent in Peru. In the three economies with larger gas fuel shares in electricity generation, inefficiencies in gas production or transportation can be readily passed on to power producers, who have nowhere else to turn for their gas and have limited flexibility to shift from gas to other fuels. Moreover, each has a single monopoly or dominant electricity supplier which can pass on any additional gas costs to electricity consumers. While the Philippines have introduced power sector competition and Viet Nam may do so too, competing power producers will have to buy gas from the same source, so the effective scope for competition among them will be somewhat curtailed.

Among the recent developers, it is worth noting that the Philippines are seriously considering how to move their gas market towards competition as gas production expands. A government circular issued in 2002 envisions requiring that access to spare capacity at gas pipelines and LNG facilities be made available to all competing gas suppliers on a non-discriminatory basis. Spare capacity is that which the owner or operator does not need to serve its own customers or to honour third-party contracts for gas transportation. While the owner or operator would still be privileged, the scope for competition would expand as new pipelines and LNG facilities are built.

DOMINANT SUPPLIER WITH COMPETITION AT THE EDGES

Hong Kong, Mexico, New Zealand and Russia are economies in which the gas market is dominated by a single firm but a minor portion of gas is produced by competing firms. There is no general pattern in this group with respect to export-import balances; Hong Kong imports all its gas, Mexico imports a small percentage, New Zealand is self-sufficient, and Russia is a major exporter. In the case of Hong Kong, a single company imports natural gas from a single producer in mainland China, but residential and commercial customers are served by town gas and LPG suppliers. Mexico has a constitutionally mandated monopoly on domestic gas production, but allows competition from gas imports, which are growing. New Zealand's gas market is legally deregulated, with eight different gas producers, but 94 percent of its gas is produced by the largest two, which often operate in partnership, and 76 percent is produced by the top firm alone. In Russia, several competing firms together produce about one-eighth of total gas output, but the remaining seven-eighths are still produced by Gazprom, even though it is no longer a legal monopoly and even though a substantial percentage of its shares are now privately owned.

Most of the economies with a dominant gas firm have a significant degree of vertical integration between their gas and electricity markets, inasmuch as a major portion of power is generated from gas and most gas must be purchased, as a practical matter, from the dominant gas firm. In Hong Kong, where about a quarter of the power is generated from gas, all the gas-fired power plants are owned by a single power producer. In Russia, where more than half of the electricity is generated from gas, four-fifths of the power is produced by the state-owned electric utility. In such cases, inefficiencies in gas production are readily passed on to power producers, who have limited flexibility to shift to other fuels, and power producers can pass on increased gas prices in their rates to electricity consumers, who usually have no alternative source of power.

MONOPOLY OR DOMINANT SUPPLIER WITH TRANSPORT PRICING ISSUES

Russia (described in the preceding section) and China have gas markets in which the prices of gas to domestic consumers may not fully cover the costs of gas production and transportation. Consequently, the incentives for construction of transportation infrastructure to bring gas to such consumers appear to be weak. By contrast, incentives for construction of transportation pipelines to serve gas export markets, where prices of gas are market-determined, appear to be adequate.

In Russia, domestic gas prices have been regulated at levels far below those that would obtain from the interplay of supply and demand in a competitive marketplace. The regulated domestic gas prices paid by Russian industry have rarely been as high as 60 percent of the market-determined prices for exportation of gas to Europe, and they have often been far lower. More importantly, it would seem that domestic gas prices have often fallen well below costs of production. In such a situation, it is hard to see how private capital might be attracted to pipeline construction. However, the government intends to bring domestic gas prices in line with export gas prices by 2007.

In China, gas transportation projects in principle receive a generous rate of return which would appear to provide an adequate incentive for construction of those projects that receive government approval. However, city gate gas prices are often capped at levels significantly below the total costs of production and transportation, on the basis of an "affordability" criterion which seeks to limit overall residential gas bills to 6 percent of average income. Production of gas is shared by three state-owned firms with separate service territories, which are fully compensated for their costs. So in practice, city-gate price caps have been sufficient to fully cover production costs but not always to fully cover transportation costs. Hence, it may be difficult for many pipeline projects to recover their costs, especially where the distances from wellhead to city gate are great. Incentives for investment in pipeline projects may thus be weak, making it hard to meet growing gas demand.

ECONOMIES WITH WHOLESALE COMPETITION IN GAS MARKETS

A number of APEC economies have a significant degree of wholesale competition in their gas markets, with a single buyer in each geographical area buying gas from competing producers. These economies include Japan, Korea, Singapore, Chinese Taipei and Thailand. In Japan, Korea and Singapore, all gas is imported from competing producers abroad, and in Chinese Taipei, 95 percent of gas is imported. In Thailand, however, only about a fifth of gas is imported, so that the wholesale market encompasses a number of competing domestic gas producers. Most of the economies in this group have well-developed local gas distribution grids, but Thailand does not.

Within APEC, Asian gas-importing economies are highly reliant on supplies from Asian gas exporters, namely Brunei Darussalam, Indonesia and Malaysia, which have had vertically integrated gas markets. The total share of LNG from these three exporting economies is 47 percent in Korea, 62 percent in Japan and 100 percent in Chinese Taipei. By contrast, only 3 percent of LNG in Korea and 14 percent of LNG in Japan is imported from Australia or the United States, which are at a fairly advanced stage of reforming their gas markets. Hence, the gas prices paid by consumers in APEC gas-importing economies are dependent not only on the design of domestic gas markets, but also on gas market design in Asian APEC gas-exporting economies.

However, the Asian gas-importing economies have differed in the extent to which they have diversified supply sources. Thailand imports gas only from Myanmar, while Singapore and Chinese Taipei import gas only from Indonesia and Malaysia. Japan and Korea, however, import gas not only from Indonesia and Malaysia, but also from Brunei Darussalam and Qatar. In addition, Korea imports some gas from Oman, while Japan imports a portion of its gas from Australia, the United States, Abu Dhabi and the United Arab Emirates.

Most Asian gas importers have a significant degree of vertical integration between their gas and electricity markets, since a major share of power is generated from gas and all gas-fired power plants must obtain fuel through a single gas buyer. The gas share of generating capacity ranged in 1999 from a very high 42 percent in Thailand to 26 percent in Korea, 22 percent in Japan, 15 percent in Singapore and 14 percent in Chinese Taipei. There is growing competition from independent power producers (IPPs), which accounted for 14 percent of generating capacity in Korea in 2000, 15 percent in Chinese Taipei in 2002, and 27 percent in Thailand in 2001. But all power producers must buy gas from the same supplier. So the scope for competition among gas-fired plants, which account for a very large share of new generating capacity, is limited to capital and non-fuel operating costs. Moreover, with the large share of capacity that is gas-fired, power producers have limited flexibility to shift to other fuels in response to higher prices. Thus, the single gas supplier has significant market power to pass on inefficiencies in gas procurement, shipping and processing, as well as in the construction and operation of LNG facilities and pipelines, in higher gas prices to power producers.

The Japanese case is somewhat particular in that there is a dual buyer for gas in most regions rather than a single buyer. Electric utilities import their own gas through their own LNG terminals, while gas utilities import gas for industrial, commercial and residential consumers through separate LNG terminals. Moreover, there is little competition in power markets, where IPPs at present account for less than 1 percent of generation and generating capacity. So with respect to the power sector, the electric utility in each region is in effect the single gas supplier to itself. It can pass on inefficiencies in procurement, shipping and processing, as well as in the construction and operation of LNG facilities, in higher prices to electricity consumers, who have few alternative power sources.

Some Asian gas-importing economies have embarked upon reform efforts which should eventually open up their markets to retail competition. In Singapore, under the Gas Act of 2002, gas transportation functions will be unbundled from retail supply. Access to gas pipelines and designated LNG facilities is to be provided on a non-discriminatory basis. Since a large portion of the public is served by the economy's gas distribution network, several competing retailers may well emerge, each negotiating for gas supplies from producers abroad.

In Korea, a proposal was made in 1999 for KOGAS to provide open access to all LNG, pipeline and storage facilities as of 2003. To ensure that competing suppliers are treated in a non-discriminatory fashion, the proposal would divest KOGAS of most functions that do not relate to gas transportation. At a later stage, open access would be extended to gas distribution, with regional distribution monopolies unbundled into separate distribution and retail supply firms. Competing suppliers would then be able to use the distribution grid on non-discriminatory terms to bring gas to small residential and commercial customers. This would be a significant step since small consumers constitute two-fifths of Korea's gas market. However, it is not clear at what point or to what extent the reform proposal will be implemented.

In Japan, a proposal has been made to require that the owners of LNG facilities make public the amount of capacity at such facilities that is not being utilised, negotiate for use of such capacity by third parties, and explain why access to spare capacity is denied, if that is the case. Proposals have also been made to gradually extend access to natural gas pipelines to all customers, rather than just large industrial and utility customers, and to provide access to all pipelines, rather than just those owned by gas companies. These proposals were endorsed by the Advisory Committee for Natural Resources and Energy in the Ministry of Economy, Trade and Industry (METI) in February 2003. If they are enacted into law, Japan will have negotiated third-party access for LNG facilities and regulated third-party access for gas pipelines, expanding opportunities for competing gas retailers and competing power producers to enter the marketplace.

ECONOMIES WITH CUSTOMER CHOICE IN GAS MARKETS

A few APEC economies have provided most of their larger gas consumers and a growing number of smaller gas consumers with a choice of suppliers. These include Australia, Canada, Chile and the United States. Of these economies, Australia and Canada are net gas exporters while the United States has substantial domestic gas supply and Chile is highly reliant on gas imports. All but Chile have well-developed gas distribution grids in most urban population centres.

Under the federal systems of government in Australia, Canada and the United States, regulatory authority over the transmission system of high-pressure gas pipelines resides with the federal government while regulatory authority over local distribution grids resides with the states, provinces or territories. In each of these economies, the federal government has provided for open and non-discriminatory access to the transmission network. As a result, large industrial firms and electricity generators, which can directly link to the network of high-pressure pipelines, have all obtained a choice of gas suppliers. However, while some states, provinces and territories have provided for open access to local distribution grids, others have not. Thus, residential and commercial customers, who must buy gas from low-pressure pipelines, do not all have a choice of suppliers. In the United States, for example, twenty-two of the fifty states have given such customers a choice of retail suppliers and another ten are considering doing so. In Canada, small customers have been granted a choice of suppliers in seven out of eight provinces. In Australia, all gas users in five out of seven states and territories will be able to choose their suppliers as of late 2003.

Among the economies providing for customer choice of suppliers in retail gas markets, there are differing degrees of competition in gas production and retail supply. In Chile, while domestic gas production is reserved for the state (as in Mexico), most natural gas is purchased from several competing producers in neighbouring Argentina (whereas Mexico's import share is currently very small), and there is also competition from town gas and LPG. In Australia, there are several competing domestic gas suppliers, and most states and territories have two or more competing gas retailers. In Canada and the United States, whose gas markets are closely linked by an extensive pipeline transmission network, there are literally hundreds of competing gas producers, among whom competition in many places is quite intense. Most states and provinces that have provided for retail choice in North America have at least two competing retail suppliers, while a few have several and New York actually has had as many as fifty.

In this group of economies, there is little integration between natural gas and power markets. Although a growing share of electricity is generated from natural gas, there are many competing electricity generators, and each electricity generator has a choice among many gas suppliers. Because of the competitive pressures in both sectors, productive efficiencies and cost savings in the gas sector should be largely passed on to consumers in the electricity sector.

SUMMARY OBSERVATIONS

It is interesting to note that being a major gas producer does not preclude having a fully competitive gas market with customer choice. It is true that many major gas producers have vertically integrated gas monopolies, and that almost all gas monopolies reside in economies that are net gas exporters. However, it does not follow that economies that are net gas exporters have all chosen to retain gas monopolies; Australia and Canada are clear counter-examples.

APEC economies which are highly reliant on natural gas imports have introduced a substantial degree of wholesale competition into their gas markets, and some have chosen to begin introducing retail competition as well. But Asian APEC economies which are major gas exporters have taken fewer measures to introduce competition, and their gas markets have generally operated as vertically integrated monopolies. Since Asian APEC importing economies are highly reliant on a few APEC gas exporters, it may be difficult for the importing economies to benefit fully from domestic gas market reform efforts unless there are further gas market reform efforts in exporting economies.

IMPACTS OF GAS MARKET REFORM

INTRODUCTION

Reform of gas markets in APEC economies can be expected to have a number of benefits. In basic economic terms, reform should result in greater competition, which should result in greater productive efficiency, which should lower gas prices and boost gas demand. For economies that are major gas importers, lower gas prices should increase output by freeing up income for purchase of additional gas and products other than gas. For economies that are major gas exporters and produce gas at a low price relative to other economies, enhanced demand from reform of gas markets in importing countries should increase output by enhancing export opportunities.

Since competitive markets use prices to balance supply and demand, market reform may also make gas prices more volatile. Where gas needs grow faster than available supply, for example due to rapid growth in electricity demand, prices in competitive gas markets may increase dramatically. A sharp ramp-up in prices may likewise occur where traditional supply sources suddenly become unavailable, for example due to conflict or political unrest. The sharp increases in price, in turn, should sharply boost incentives to produce and explore for gas, as well as to import gas from alternative sources. When additional gas comes on the market as a result, prices should subside.

It is important to recognise as well that gas markets do not operate in isolation. There are strong gas trade links in the APEC region, so that the impacts of market reforms in gas-importing economies may be affected by the extent to which markets have become more competitive in gas-exporting economies. There are also strong links between gas and power markets, since a large share of electricity is generated from gas, so that the impacts of electricity market reform may depend in large part on the extent to which gas markets have become more competitive.

This chapter examines the available evidence in support of these assertions, drawing heavily upon the gas market sketches that are presented later in this report. It starts by reviewing some projections of the economic benefits that might be expected if competitive energy market reforms were adopted throughout the APEC region. It then examines the actual impacts that market reforms have had on gas prices and availability in North America and Australia, as well as the potential for greater competition to reduce gas prices in Northeast Asia. Finally, it examines how the impacts of gas market reform in various economies are related to electricity market reforms in those economies and to gas market reforms in other economies.

PROJECTED IMPACTS OF APEC ENERGY MARKET REFORM

A recent study on *Deregulating Energy Markets in APEC* has estimated that major benefits would flow from comprehensive liberalisation of energy markets in APEC economies beyond the reforms that have already taken place. The benefits would include higher productivity, lower energy prices, and greater output. The gas sector would expand significantly due to a more competitive cost structure and greater demand for gas in the power sector. However, the benefits would be substantially reduced if only the gas sector were reformed and other energy sectors were not.[1]

IMPACTS ON ECONOMIC OUTPUT

At the macroeconomic level, the study finds that comprehensive reform of energy markets would raise the APEC region's GDP in 2010 by US$71 billion (at 1999 prices) or 0.3 percent. The

[1] APEC Energy Working Group and Abareconomics (2002).

relative impact on GDP would be greater in developing economies excluding China (0.6 percent) and newly industrialised economies (0.4 percent), and somewhat lower in developed economies (0.25 percent), while the percentage increase for China would be similar to that for APEC as a whole. The economic boost would be greatest for economies with large energy sectors since a relatively large share of their output would be directly affected by the reform.

IMPACTS ON INDUSTRIAL MIX AND ENERGY INTENSITY

Structurally, comprehensive reform of energy markets in APEC economies would favour energy-intensive industries such as ferrous and non-ferrous metals, minerals, chemicals, rubber and plastics by lowering the costs of their energy inputs. Consequently, the study finds, APEC economies would become more energy-intensive, with energy input per unit of real GDP in 2010 increasing by over 1 percent for APEC as a whole and for newly industrialised economies, about 0.5 percent for developed economies in APEC, roughly 2 percent for China, and over 3.5 percent for other developing economies in APEC.

IMPACTS ON GAS DEMAND

APEC-wide energy market reform would substantially increase demand for gas by making it more competitive with other fuels for power generation. The study finds that natural gas consumption in 2010 would increase by nearly 5 percent in APEC as a whole, somewhat less than 3 percent in developed APEC economies, more than 10 percent in newly industrialised APEC economies, and by 13 percent in China and other developing economies of APEC. The impacts on gas use would be greatest in those economies that are furthest from competitive energy markets and in which gas use is already important.

IMPACTS ON GAS SUPPLY

Reform of energy markets in the APEC region would have an even greater impact on production of gas than on demand for gas in the region, since more efficient production and reticulation of gas would make APEC economies more competitive, increasing gas exports outside the region. This impact would be greatest in those economies that have the least competitive gas markets and largest indigenous gas reserves. In particular, the study projects that gas production in Indonesia, Malaysia and Mexico would increase by 14 to 20 percent.

IMPACTS ON TRADE

The study finds that gas imports and exports in the APEC region would both be notably affected by energy market liberalisation. LNG imports in 2010 would be 8 percent higher in Japan and 10 percent higher in Korea than they would be in the reference case projections, while smaller increases in gas imports would occur in countries like Chile and Mexico. On the export side, key beneficiaries of energy market liberalisation would be Indonesia and Malaysia, whose exports would grow because they have large gas reserves and because they would become more competitive with other major gas-exporting economies like Canada.

IMPACTS ON INVESTMENT REQUIREMENTS

Almost by definition, increased gas supply and demand would increase needs for investment in gas production and transportation. Exporting countries would need to expand gas pipelines and LNG export facilities. Importing countries would need to expand LNG receiving terminals and gas distribution networks. The report does not attempt to estimate the additional investment in gas supply infrastructure that market liberalisation would necessitate, but in view of its projections that liberalisation would raise gas demand in the APEC region by 55 million tons of oil equivalent in 2010, it concludes that the required investment "is likely to be high."

IMPACTS ON ENERGY SECURITY

The study points out "achievement of energy security objectives in APEC is closely linked to the liberalisation" of gas and electricity markets. It notes that reform of these markets "can be expected to improve the reliability of access to energy resources by providing economic incentives to expand interregional gas pipelines and electricity networks, particularly in the Asian APEC region where network industries are relatively less developed. Such developments not only provide opportunities for APEC economies to complement each other in the provision of energy resources but also to lower the cost of energy supply."

IMPACTS OF GAS MARKET REFORM ALONE

If the gas sector were liberalised but other energy sectors were not, the benefits would be substantially reduced. The study explains this by noting that gas represents only a small share of energy production and use in APEC and that roughly four-fifths of APEC gas production occurs in Australia, Canada and the United States, which "already have relatively open and competitive gas markets." In any case, since a large and growing share of gas demand comes from the generation of electricity, it stands to reason that failure to liberalise power markets would limit the impact of reform in gas markets. Nonetheless, the study finds that certain economies with sizeable gas reserves, like Malaysia, Mexico and Indonesia, would still benefit substantially from gas market reform because they would become much more competitive with other gas producing economies. For Mexico and Indonesia, the study finds, reform of gas markets alone would boost gas exports in 2010 by 20 percent, almost as much as with reform of all energy markets.

EMPIRICAL IMPACTS OF REFORM ON GAS PRICES AND AVAILABILITY

Only a few of the APEC economies have had sufficiently widespread and lengthy experience with gas market reform to allow an empirical assessment of reform's actual benefits. The most comprehensive experience has been in Canada and the United States, where there are hundreds of competing gas producers, wellhead gas prices were deregulated in 1985, and many customers are allowed to choose their retail gas supplier. Australia has had significant experience with gas market reform as well, with deregulated wellhead gas prices and retail competition in several areas, although there are only a few competing producers. In Northeast Asia, while reforms are at a much earlier stage, there is some empirical evidence that the eventual benefits could be quite sizeable. This section will examine how the price and availability of gas have been affected by regulatory reform efforts to date and might presumably be affected by regulatory reforms that are anticipated.

GAS PRICE REDUCTIONS FOLLOWING MARKET REFORM IN NORTH AMERICA

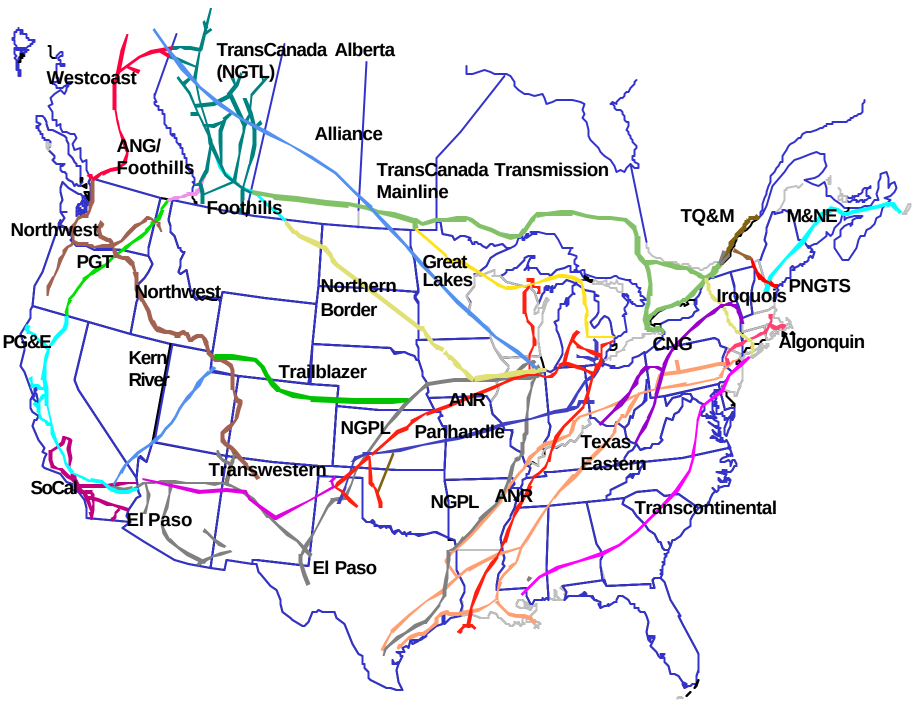
North American experience probably provides the best available opportunity to evaluate the actual impact of gas market reforms on gas prices and availability. The gas markets of Canada and the United States are linked by an extensive transmission grid of high-pressure pipelines. The grid is used to move large amounts of Canadian gas to the US market, as well as smaller amounts of US gas to the Canadian market. Consequently, changes in gas demand in either economy may significantly affect gas prices in both.

Moreover, the United States and Canada have similar gas market structures and reformed their gas markets for similar reasons on similar schedules. Both before and after market reforms were implemented, both economies have had many different gas producers. In the early 1980s, both economies had a "bubble" of excess gas supply due to high regulated prices that encouraged gas production but dampened gas demand. In the mid-1980s, federal governments in both economies fully deregulated wellhead gas prices and required that access to the gas pipeline network be provided to all gas suppliers on equal terms. This allowed gas pipeline companies, large industrial firms and electricity generators to buy gas from the cheapest available source. Subsequently, many states and provinces have provided for open and non-discriminatory access to local distribution networks, extending competition to small commercial and residential customers.

In the United States, the Natural Gas Policy Act of 1978 ended wellhead price controls for "new" gas as of 1985, and the Natural Gas Wellhead Decontrol Act of 1989 lifted all remaining wellhead price controls. Order 436, issued by the Federal Energy Regulatory Commission (FERC) in 1985, required regulated third-party open access to the high-pressure gas transmission network. Order 636, issued in 1992, required interstate pipeline companies to unbundle their supply and transportation functions. This means that pipelines may only sell gas through functionally separate affiliates, helping to ensure that they will transport third-party gas on a non-discriminatory basis. By the end of 2001, 20 states had provided for open access to local distribution grids, allowing small customers to choose their gas suppliers, and 150 competing retail gas suppliers had emerged.

In Canada, the 1985 Agreement on Natural Gas Prices and Markets deregulated wellhead gas prices and mandated open access to high-pressure transmission lines. To facilitate regulation of open access and discourage pipelines from discriminating in favour of their own gas, the NEB Act required that TransCanada and other gas pipeline companies functionally unbundle their transmission functions from their marketing activities, with information firewalls between the two. Subsequently, several provinces have allowed smaller customers to choose suppliers over local distribution grids.

Figure 8 North American Gas Transmission Grid

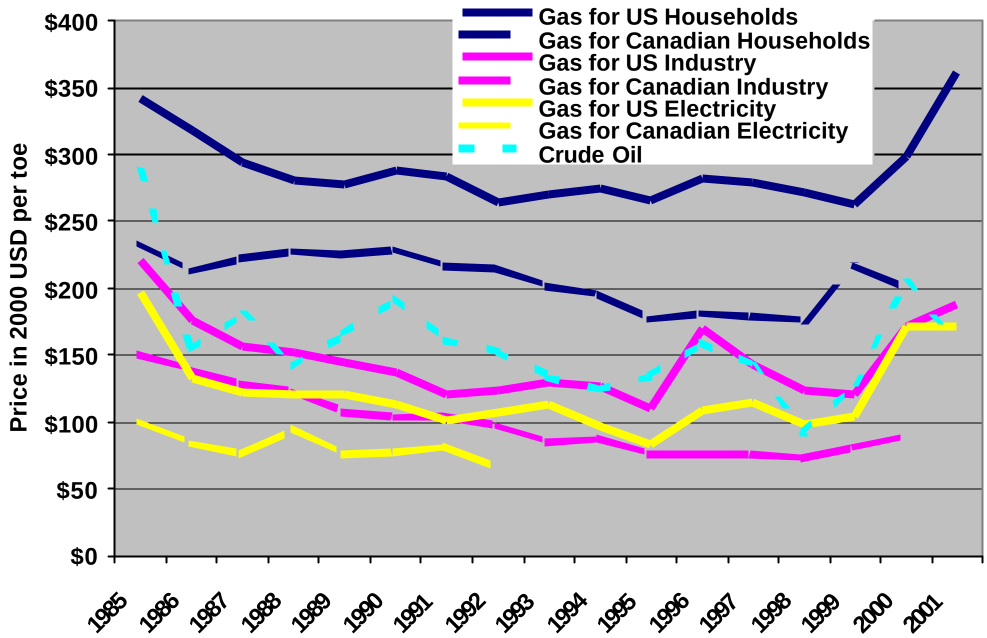


Source: National Energy Board

In both the United States and Canada, deregulation of wellhead natural gas prices and mandatory access to the gas transmission grid resulted in steep price declines for gas users. For industrial customers, the real price in 2000 US dollars per tonne of oil equivalent was halved from \$221 in 1985 to \$110 in 1995 in the United States and from \$150 in 1985 to \$73 in 1998 in Canada. For electric power producers, the real price was cut by more than half in the United States (from \$197 to \$84 per toe between 1985 and 1995) and by a third in Canada (from \$100 to \$66 per toe between 1985 and 1992). Meanwhile, residential and commercial gas prices declined in real terms by a third in the United States (residential prices from \$342 to 266 per toe), and household gas prices declined by a quarter in Canada (from \$233 per toe in 1985 to \$176 per toe in 1998).

Nonetheless, despite expanding transmission grid links, prices in the two North American economies have continued to differ significantly. As can be seen in the figure, prices in every end-use sector are substantially lower in Canada than in the United States. This may have to do with greater average distances for transportation of gas from producers to customers in the United States. In addition, there has been no consistent relationship between delivered gas prices and international crude oil prices. This is probably because gas demand (largely for power production) and oil demand (mainly for transport) are imperfectly correlated, and because gas is supplied to end-users almost entirely from within North America while half of the oil comes from outside.

Figure 9 Sectoral End Use Gas Prices vs Oil Prices in North America, 1985-2000



Source: International Energy Agency price data and US Department of Commerce price deflators

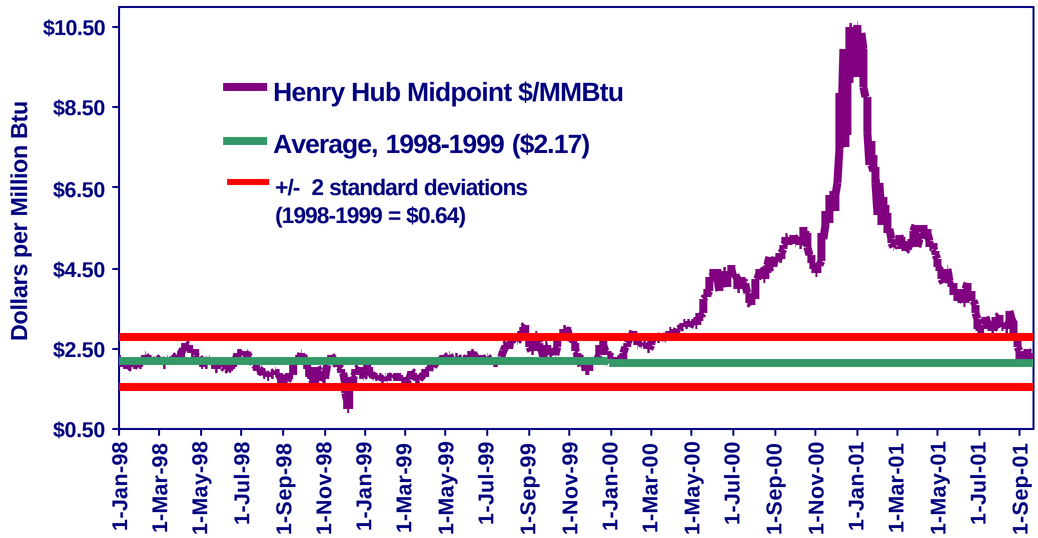
The sharp price declines that initially followed deregulation of wellhead gas prices in North America can be largely attributed to the fact that prices had been regulated at what became unsustainably high levels. High regulated prices encouraged production and discouraged consumption, so that available supply substantially exceeded the quantity demanded. When wellhead prices were deregulated and unbundled from transportation charges, so that pipelines and other large customers could buy from the cheapest suppliers, it was natural for prices to fall.

However, the more sustained gas price declines that continued through the mid 1990s would seem to be mainly due to improved efficiency in gas production and transportation, which was fostered by the competition among gas producers that the reforms made possible. Greater competition, combined with the availability of new technologies, cut the costs of finding and developing gas fields by as much as half. Lower wellhead prices, resulting from greater competition and the initial correction from excessive prices under regulation, helped to boost demand, which in turn raised throughput on the pipeline grid and lowered the cost per unit of gas transported.

SUPPLY RESPONSE TO GAS PRICE SPIKES IN NORTH AMERICA

From mid-2000 through mid-2001, the North American natural gas market saw major price spikes that illustrate the potential for price volatility in competitive gas markets in the face of sudden changes in demand or supply. Demand for gas increased sharply due to severe weather which raised gas and electricity use for heating and cooling, completion of many new gas-fired power plants by independent power producers, and low rainfall which reduced hydropower output and required gas-fired powerplants to be used more intensively. As a result, prices at the Henry Hub and Alberta reference points for the market increased to as much as four times normal levels by early 2001. Supply of gas was also limited in some markets, notably California, by constraints on pipeline transmission capacity, resulting in prices that were far above the Henry Hub price. However, by late 2001, prices at the Henry Hub had subsided to normal levels, and the differential between Henry Hub prices and prices at the California border had diminished to near zero.

Figure 10 Henry Hub Daily Spot Prices 1999-2001 vs Normal Range 1998-1999



Sources: Financial Times Energy and Gas Daily

The rapid adjustment of prices can be largely attributed to the responsiveness of gas producers and pipelines to the profit incentives that higher prices temporarily offered. In the United States, the number of gas drilling rigs in operation more than doubled between April 1999 and December 2000, and the average number of rigs in operation was 45 percent higher in 2000 than in 1999. With a rise in gas well completions, production increased by 4 percent between 1999 and 2000. More than 60 pipeline construction projects were completed in 1999 and 2000, providing a 15 percent boost in gas transmission capacity over what was available in 1998. In Canada, a doubling of average Alberta gas prices between 1999 and 2001 saw gas well completions increase by half.

GAS PRICE REDUCTIONS FOLLOWING MARKET REFORM IN AUSTRALIA

Outside of North America, the APEC economy with the most extensive gas market reform is probably Australia. Gas market functions in Australia were effectively unbundled by the Gas Access Code that went into effect in 1997. The Access Code applies to almost all major gas transmission pipelines and to gas distribution networks in major cities. It provides for access to pipelines on a negotiated basis, with surplus capacity offered to third parties according to terms and conditions set by the regulator. Since pipeline owners have no financial interest in gas production facilities, they have no incentive to discriminate among producers in providing access. Most gas distribution companies also have retail supply businesses, but the Access Code requires that distribution and retail supply be carried out by functionally separate entities, with restrictions on information exchange between them, so distributors cannot easily discriminate on behalf of affiliated retailers.

Australia has several competing gas producers, but production is still somewhat concentrated. On the eastern coast, Santos, BHP Billiton and Exxon-Mobil account for most production from Australia's central and southeastern gas basins, which mainly serve the domestic market. On the western coast, Woodside Energy, Shell, Chevron and Texaco are the dominant producers in the economy's northwest gas fields, from which most production is exported. There are no gas pipelines connecting Australia's coasts, so there are separate eastern and western gas markets.

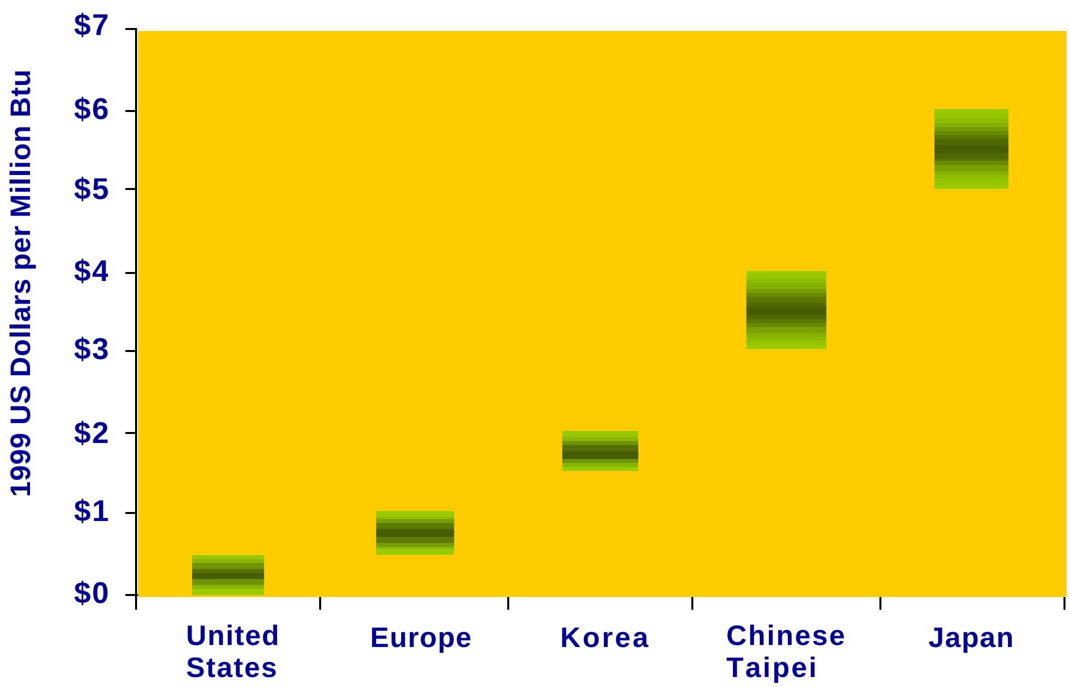
Yet even with the rather limited competition that exists among different gas producers, there is substantial evidence that market reforms in Australia have led to lower consumer prices for gas. Gas prices for industrial and residential gas consumers in Australia fell by an average of 22 per cent between 1994 and 1998 in real national currency terms. In Victoria, one of the first states to reform its gas market at the retail level, business customers saw real gas prices fall by 8 percent between 1991-92 and 1996-97, while small businesses had their gas prices decline by 30 percent between July 1996 and January 2001. For household customers, whereas real gas prices increased by 7 percent in the earlier five-year period, they fell by 11 percent in the latter five-year period.

OPPORTUNITIES FOR GAS PRICE REDUCTIONS IN NORTHEAST ASIA

Three economics in Northeast Asia are entirely dependent upon LNG imports for their natural gas supply. These include Japan, Korea, and Chinese Taipei. In these economies, the delivered price of gas depends not only on the landed cost of LNG fuel, but also on the charges for use of the LNG terminals and pipelines through which fuel is processed and transported to users.

In point of fact, LNG terminal charges vary enormously from one economy to another. While they are typically around $0.50 per million Btu in the United States and $1 in Europe, they are far higher in Asia. Perhaps more interestingly, LNG terminal fees vary a great deal within Northeast Asia itself. While they are usually around $2 per million Btu in Korea, they typically range from $3 to $4 in Chinese Taipei and from $5 to $6 in Japan. Otherwise stated, LNG charges are double European levels in Korea, more than triple in Chinese Taipei, and up to six times higher in Japan.[2]

Figure 11 Indicative LNG Terminal Charges in APEC Economies and Europe, 1999



Source: Williams (2003)

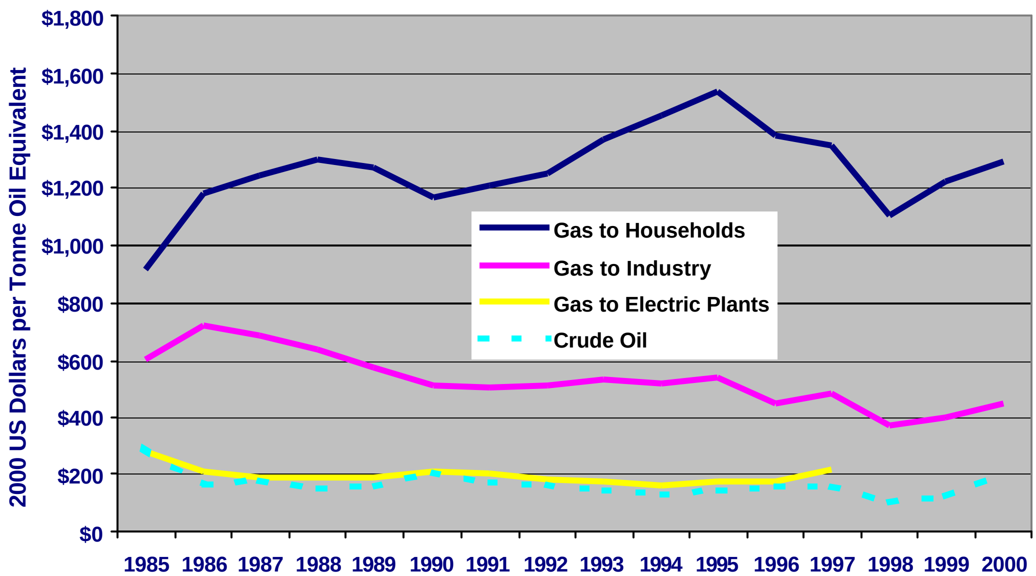
These three major gas-importing economies are located in the same region, with similar costs for the materials and equipment that would be involved in LNG terminal construction. While unit labour costs are substantially higher in Japan than in Korea or Chinese Taipei, labour costs should constitute a relatively small share of total costs in capital-intensive projects like LNG facilities. Moreover, unit labour costs in Japan should be comparable to those in Europe. Hence, the fact that LNG terminal charges vary by a factor of three within Asia and a factor of six among industrialised economies in Asia and Europe is difficult to explain other than in terms of the relative efficiency with which terminals are built and operated. It would thus seem that increased competition in natural gas supply might substantially reduce delivered LNG costs in Northeast Asian economies.

[2] Williams (2003).

An important component of delivered natural gas prices in Northeast Asia, on top of LNG commodity charges and terminal charges, is the cost of gas transmission and distribution by pipeline. Typically, costs to large industrial gas users will include a substantial charge for high-pressure pipelines, to which such users can often connect directly. Costs to residential and commercial customers, who cannot connect directly to the high-pressure grid, will also include a substantial charge for the low-pressure pipelines that distribute gas to individual buildings.

The role of pipeline transportation charges is well illustrated by the case of Japan. Electric utilities, which import their LNG directly into their own terminals, pay LNG prices that are linked by contract to crude oil prices. Industrial firms, whose costs typically include a substantial charge for transmission over high-pressure pipelines, on average pay about twice as much for their gas as power companies. Households, whose costs include charges not only for transmission but also for local distribution, typically pay five or six times as much for their gas as power companies do.

Figure 12 Sectoral End-Use Gas Prices and Crude Oil Prices in Japan, 1985-2000

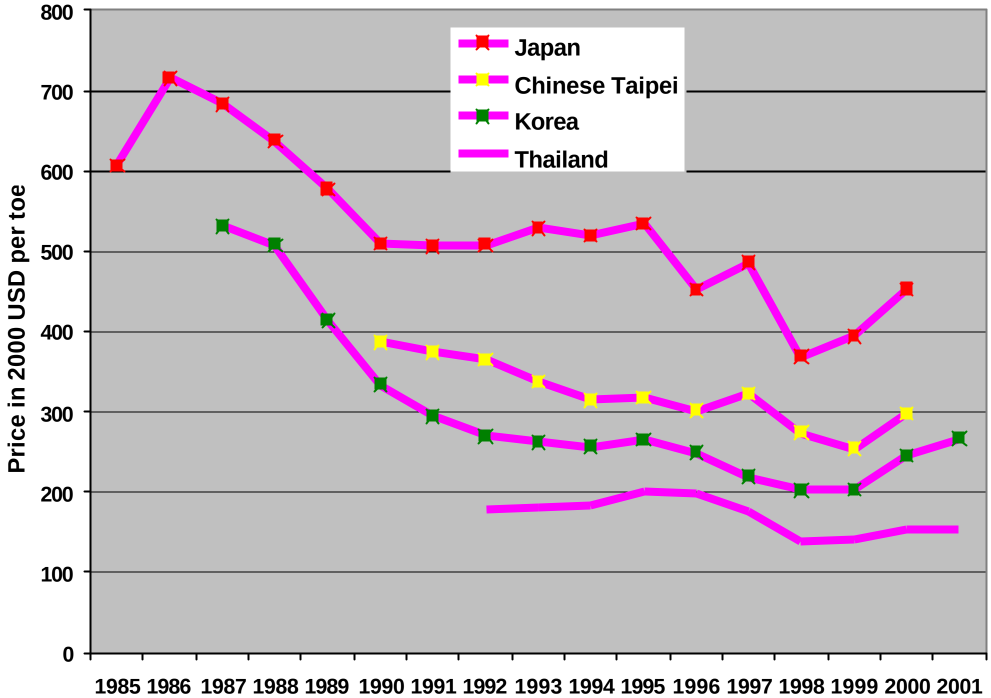


Source: International Energy Agency price data and US Department of Commerce price deflators

The burden of LNG terminal charges and high-pressure pipeline transmission charges to industry differs substantially among APEC economies in Southeast Asia. Delivered gas prices to industry are substantially higher in Japan than in Chinese Taipei or Korea, as indicated in figure 13. Delivered gas prices to industry in Thailand, where most gas is produced indigenously and transportation costs are therefore much lower, are shown as well for reference.

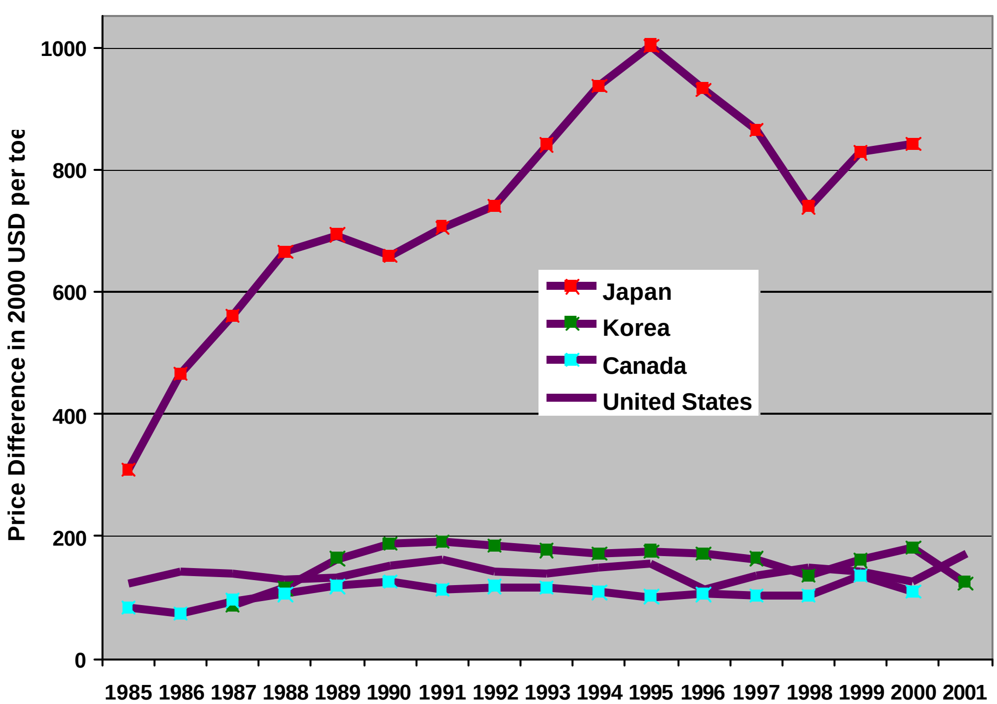
The potential for greater competition to reduce gas pipeline distribution charges would seem to be substantial, as shown in figure 14. The difference between industrial and residential gas rates in Japan since 1990 has ranged from US$659 to $1,003 per tonne oil equivalent. By comparison, the difference between industrial and residential gas rates has ranged from $112 to $173 per toe in the United States, from $101 to $134 per toe in Canada, and from $123 to $191 per toe in Korea. Assuming that the difference between industrial and residential rates approximates distribution charges (which generally apply to residential customers but not industrial customers), distribution charges for natural gas in Japan each year have been about 4.3 to 6.6 times as high as those in the United States, 5.2 to 10.0 times as high as those in Canada, and 3.5 to 5.7 times as high as those in Korea. These numbers appear to imply some room for improving the efficiency of natural gas distribution by fostering competition among retail suppliers for residential customers' business.

Figure 13 Industrial Gas Prices in Japan, Korea, Chinese Taipei and Thailand



Sources: International Energy Agency, Korea Energy Economics Institute, Thailand Energy Policy and Planning Office

Figure 14 Household Less Industrial Gas Prices in Selected APEC Economies



Sources: International Energy Agency, Korea Energy Economics Institute, US Department of Commerce

But figures on comparative distribution costs must be interpreted with caution, since a large portion of the price differential across economies is probably due to differences in the typical volume of household gas consumption. For example, while average yearly household gas consumption is just 17.4 megajoules in Japan, it is about 61.7 megajoules in Korea, or about 3.6 times as great. Since the costs of extending distribution pipelines to households do not vary much with volume, this would imply that the cost of distribution per household might well be 3.6 times as high in Japan as in Korea even if distribution systems were built and operated with equal efficiency. Yet there still appears to be room for efficiency improvement since the gap between industrial and household prices, a reasonable proxy for distribution costs, has been up to 5.7 times as high in Japan as in Korea during the 1990s, sometimes exceeding the 3.6 volume differential factor by half.[3]

SYNERGIES BETWEEN REFORM IN PRODUCING AND CONSUMING ECONOMIES

The Northeast Asian economies that import their natural gas as LNG are largely reliant on gas-exporting economies whose gas markets have operated as vertically integrated monopolies. Major gas importers, including Japan, Korea and Chinese Taipei, have some degree of wholesale competition in their gas markets, are implementing measures to expand wholesale competition, and are expected to allow some retail competition as well. Major gas exporters in the region, notably Brunei Darussalam, Indonesia and Malaysia, have had vertically integrated gas markets with just a single producer and exporter each. It follows that reform efforts in the APEC gas-exporting economies could significantly enhance the benefits of reform efforts in APEC gas-importing economies.

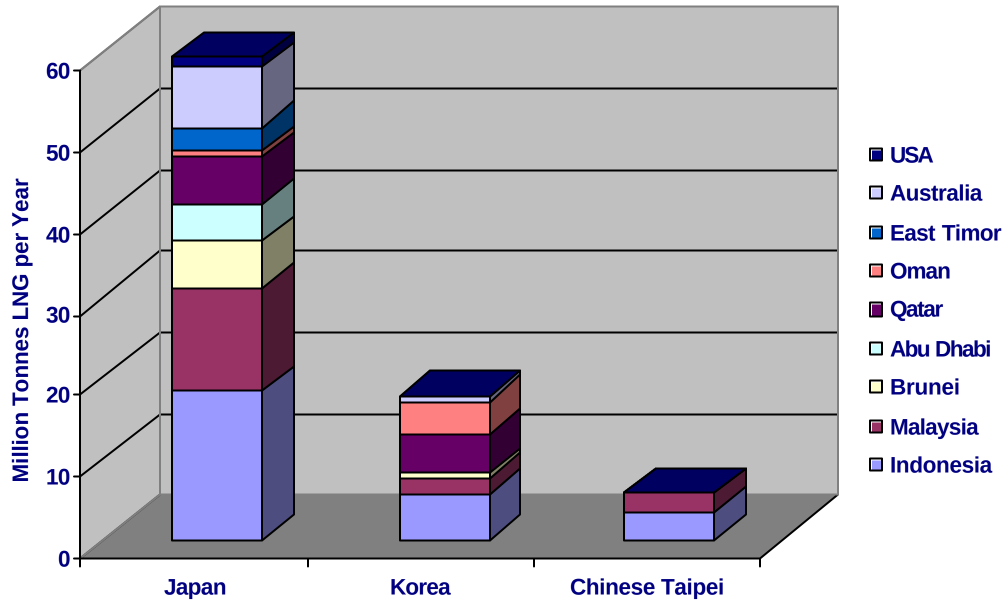
Asian gas producers have significant market advantages over more distant competitors in selling gas to Asian gas consumers. Not only do the Asian producers have lower transport costs stemming from their greater proximity to importing markets, but they also may well have lower production costs than competing exporters with more mature gas fields. With lower production and shipping costs, it should be possible for Asian gas producers to sell to Asian gas consumers at a "competitive" price even if their integrated monopolies result in production that is less efficient and more costly than it would be if several gas producers in each exporting economy were competing. This may mean that importing economies, even if they develop highly competitive gas markets internally, may not be able to obtain fully competitive bids for their purchases of gas from abroad.

Economies from which Northeast Asia imports gas under long-term and medium-term contracts are shown in figure 15. A substantial portion of the imports are from APEC economies that have had vertically integrated gas monopolies, namely Indonesia, Malaysia and Brunei Darussalam. Another large portion of the imports are from other economies with vertically integrated gas monopolies, including Abu Dhabi, Qatar, Oman and East Timor; all but the last of these are members of the Organisation of Petroleum Exporting Countries (OPEC) located in the Middle East. Some imports come from Australia and the United States, which have substantially competitive gas markets.

If the LNG contract volumes for imports into Northeast Asia are grouped by type of exporting economy, the reliance on vertically integrated monopolies is more readily apparent as in figure 16. APEC economies with vertically integrated gas monopolies account for 62 percent of contract volumes in Japan, 47 percent in Korea and 100 percent in Chinese Taipei. Non-APEC OPEC economies plus East Timor, which also have vertically integrated gas monopolies, account for another 24 percent of the LNG imports in Japan and 50 percent in Korea. Only 14 percent of the LNG in Japan and 3 percent in Korea comes from APEC economies with competitive gas markets.

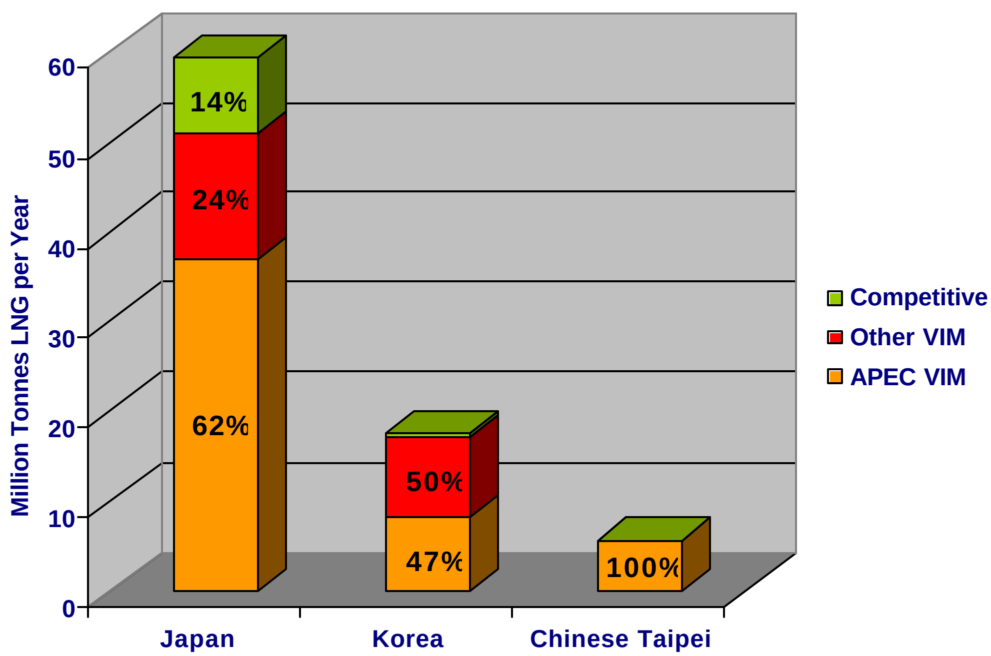
[3] Figures for city gas utilities in Japan from IEEJ. Figures for city gas utilities from Korea City Gas Association (2002). The Korean figures include some distribution to commercial and industrial customers, whose average consumption is greater than that of household customers. Thus, average household gas consumption in Korea may be somewhat lower than 61.7 MJ and less than 3.6 times as great as in Japan, implying still greater room for efficiency improvement.

Figure 15 LNG Imports into Northeast Asia in 2003 by Exporting Economy



Source: IEEJ (2002b), IEA (2002c), Cedigaz (1999).

Figure 16 LNG Imports into Northeast Asia in 2003 by Exporting Market Type



It is apparent from this analysis that there are at least two ways in which Northeast Asian APEC economies might benefit from gas market reforms in other APEC economies. One way would be to import a greater share of gas from the economies which already have competitive gas markets. The other would be for the exporting economies with vertically integrated gas markets to make their gas markets more competitive. In view of the relative costs and availability of gas from different economies, the latter route may have more potential if exporters are willing to follow it.

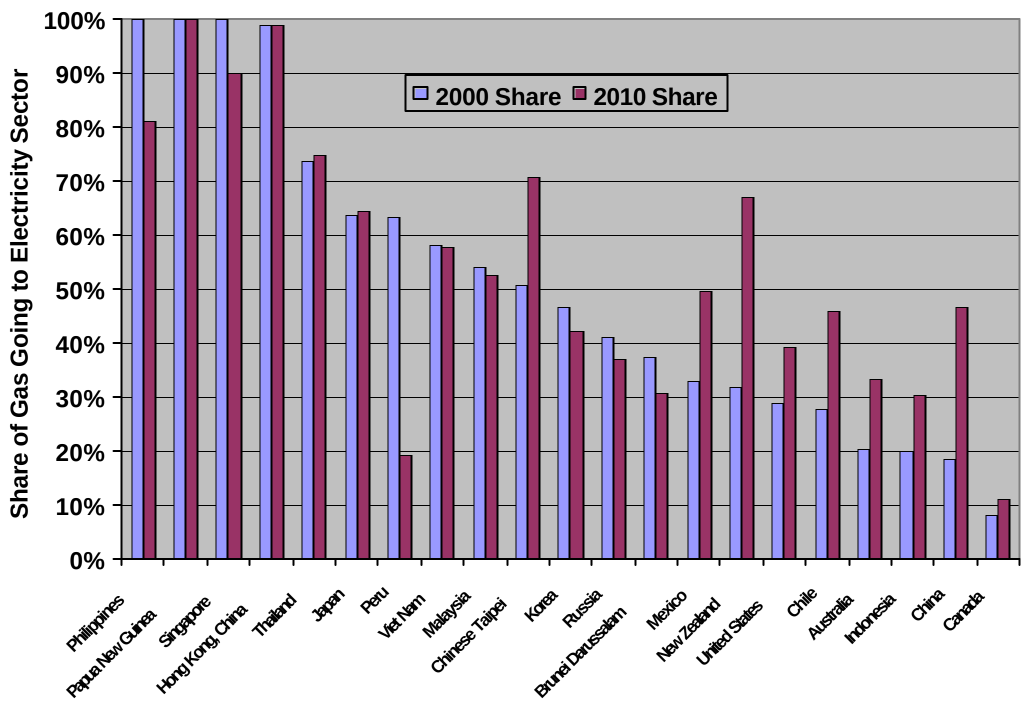
SYNERGIES BETWEEN REFORM IN GAS AND ELECTRICITY MARKETS

It is quite important to recognise that the gas and electricity markets in many APEC economies are closely linked. Sales to electricity generators account for a large and growing share of gas demand. As a result, gas market reforms that make gas supply more competitive will have a greater impact if competitive power markets oblige electricity generators to vie for the lowest-cost gas. At the same time, gas accounts for a large and growing share of electricity generation. Therefore, reforms aimed at encouraging greater competition in power markets will have a greater impact if there are also gas market reforms that make it possible to buy gas from the cheapest supplier.

THE GROWING ELECTRICITY SHARE OF GAS DEMAND

The chart below indicates the share of domestic natural gas supply that was used to generate electricity in APEC economies in 2000, along with the share that is projected to be used for power production in 2010. As the chart shows, four economies devote virtually all of their gas supply to power generation, while another five use more than half their gas to produce electricity. While the share of electricity in gas demand is projected to decline by ten percentage points or more in three economies (Philippines, Singapore, Peru), it is projected to grow by ten percentage points or more in eight (Chinese Taipei, Mexico, New Zealand, United States, Chile, Australia, Indonesia, China).

Figure 17 Electric Power Sector Share of Gas Demand in APEC Economies



Source: APERC (2002a).

Among major gas exporters that have had vertically integrated monopolies in their gas markets, it can be observed that the electricity sector's share of gas demand exceeds 50 percent in Malaysia, 40 percent in Russia, 30 percent in Brunei Darussalam and 20 percent (growing to 30 percent) in Indonesia. Thus, with respect to the internal markets in these economies, the impact of any reforms in the gas market would be significantly enhanced if there were parallel reforms in the electric power market. While independent power producers account for 43 percent of electricity production in Malaysia and about 9 percent in Indonesia, each economy retains a single buyer-retailer in its power market which may not pass on to consumers all cost reductions from a more competitive gas market just as it may not fully pass on savings from subsidised gas prices offered by the gas monopoly today.

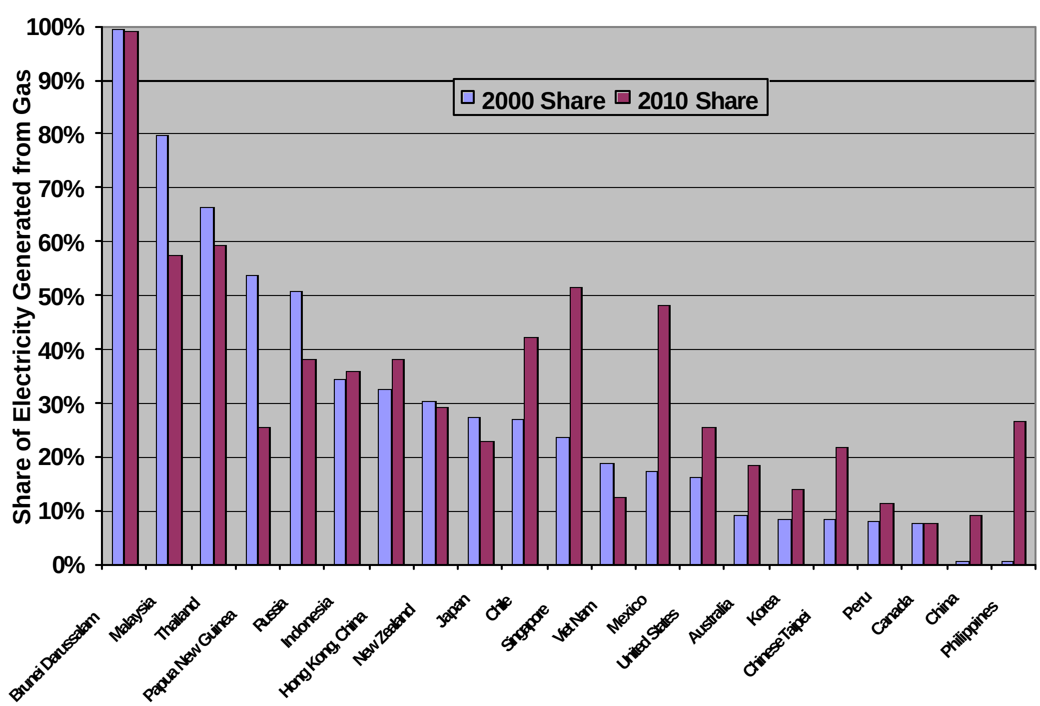
Among economies with recently developed vertically integrated gas markets, the electricity sector's share of gas demand ranges from 100 percent in the Philippines and Papua New Guinea to around 60 percent in Peru and Viet Nam. Because electricity's share of gas demand is so high, the impact of gas market reforms in these economies on the energy bills paid by final consumers would be severely limited in the absence of power market reforms. Without competition in the power market, competition in the gas market could reduce operating costs and raise profits for monopoly electric utilities, but the utilities would not necessarily pass on their cost savings to consumers. The Philippines are in fact implementing legislation that aims to make power markets more competitive.

Among gas-importing economies with single buyers of gas in their wholesale markets, the portion of gas supply devoted to power production ranges from about 100 percent in Singapore and Hong Kong to over 70 percent in Thailand, 60 percent in Japan, 50 percent in Chinese Taipei, and 40 percent in Korea. So in these economies, too, the impact of gas market reforms would be limited without competition in the power sector. While IPPs hold 14 percent of Korea's generating capacity, 15 percent of Chinese Taipei's, and 36 percent of Thailand's, they sell to a single buyer that may not pass on all savings from gas market competition to consumers. In Singapore, with four IPPs competing for retail sales, a larger share of the savings from gas market reforms might be passed on.

THE KEY ROLE OF GAS IN ELECTRICITY SUPPLY

The following chart shows the share of electricity that was generated from natural gas in 2000 and the share that is projected to come from natural gas in 2010. Five economies generated more than half of their power from gas in 2000. The share of gas in power production is projected to decline substantially in Malaysia, Papua New Guinea and Russia, but should increase by more than 20 percentage points in three economies (Singapore, Mexico and Philippines) and by 8 percentage points or more in another five (Chile, United States, Australia, Chinese Taipei and China).

Figure 18 Share of Electricity Generated from Gas in APEC Economies



Source: APEC Energy Working Group (2002) for actual 2000 shares, APERC (2002a) for projected 2010 shares.

Looking at major gas exporting economies with vertically integrated gas markets, it can be seen that the share of gas in electricity generation is nearly 100 percent in Brunei, around 80 percent in Malaysia, over 50 percent in Russia and more than 30 percent in Indonesia. It follows that power market reforms would have extremely little effect in Brunei and Malaysia and a significantly curtailed impact in Russia and Indonesia unless gas market reforms were also implemented. Since Malaysia and Indonesia have in fact liberalised their wholesale power sectors, with 43 percent of electricity in the former and 9 percent in the latter generated by independent power producers, this is of more than theoretical significance. As long as all IPPs must buy gas from the same source, they will only be able to compete with respect to capital costs and non-fuel operating costs.

Turning to economies with vertically integrated gas markets that have recently developed their gas resources, the share of gas in power production is generally quite low. While gas is used for about half of power production in Papua New Guinea, it accounts for less than 20 percent of electricity generation in Viet Nam, less than 10 percent in Peru and a very small percentage in the Philippines, where the share is expected to grow rapidly over the next ten years. In these economies, the benefits of electricity market reform would be only modestly curtailed by a failure to reform natural gas markets. However, gas market reform could still be of value to these economies in limiting the fuel costs of gas-fired power plants and in making the gas industry more efficient.

Among gas-importing economies with a single buyer in their wholesale markets, several generate a large share of their electricity from gas. The gas share of power production exceeds 60 percent in Thailand, 30 percent in Hong Kong, 25 percent in Japan and 20 percent in Singapore, where it may expand to 50 percent over the next ten years. Although the gas share of generation is below 10 percent in Korea and Chinese Taipei, it is expected to grow substantially and is far exceeded by the gas share of generating capacity, which will soon be approaching 30 percent.

Since all power producers in these economies must obtain gas from the single buyer, their fuel costs will not differ much and the effective scope for competition among them will be limited to capital and operating costs. Moreover, insofar as the share of gas-fired generating capacity is large, power producers will have limited flexibility to shift to other fuels in response to higher prices. Thus, the single buyer may be able to pass on many inefficiencies in gas procurement, shipping and processing, as well as in the construction and operation of LNG facilities and pipelines, in higher gas prices to power producers. It follows that further gas market reform, with competition at retail level and the ability of all power producers to shop directly for the lowest-cost gas or import their own gas, would significantly enhance the impacts of electricity market reform in such economies.

SUMMARY OBSERVATIONS

It is interesting to note that a wide range of economies may benefit from gas market reform, and that reform efforts in different economies tend to be mutually reinforcing. Both importers and exporters of gas may have major industrial firms, electricity generators, and other energy companies that consume gas in large quantities. Any economy that consumes a substantial amount of gas can benefit from the lower gas prices to end users that tend to result from greater competition in the procurement and transportation of gas supplies. Insofar as lower prices lead to greater consumption, economies that export gas may also benefit from expanded markets for their product when importing economies reform their gas markets. And insofar as greater competition leads to lower costs, economies that import gas will have better opportunities to procure gas at advantageous prices if exporting economies reform their gas markets.

Reform of gas markets, with deregulation of gas production and continued regulation of gas transportation, will tend to increase the volatility of gas prices in response to forces of supply and demand. Reform of electricity markets, with deregulation of power generation, will likewise tend to increase the volatility of power prices. But experience indicates that price spikes will elicit enough new supply or sufficiently suppress demand so that prices return promptly to normal levels. Market players can also use futures contracts to shield themselves from price fluctuations. And if gas and power markets are both reformed, competition in each will help to lower costs and prices in both.

OPTIONS FOR GAS MARKET REFORM

INTRODUCTION

In view of the possible benefits of gas market reform, it may be interesting for APEC economies to consider options for making their gas market more competitive. On the other hand, changes in market arrangements can be politically difficult and take a long time to fully implement. Thus, before starting down the road of reform, economies naturally wish to consider whether benefits could reasonably be expected to materialise given their particular political and economic conditions. Is the gas market large enough to allow economical production by several competing producers? Will political conditions allow sufficiently comprehensive reform to have a real impact? This chapter aims to assist their deliberations by assessing the scope for competition in gas markets of different sizes and offering a variety of policy options by which competition might be enhanced.

MARKET SIZE AND POTENTIAL FOR COMPETITIVE GAS PRODUCTION

It is sometimes argued that particular economies are too small to allow for effective competition among gas producers. There are certain economies of scale in gas production, so that if reserves are sufficiently small, it will not be cost-effective to have more than one producer or at least more than very few producers. This is actually a sort of natural monopoly argument. This section examines whether such an argument is empirically valid in light of recent experience.

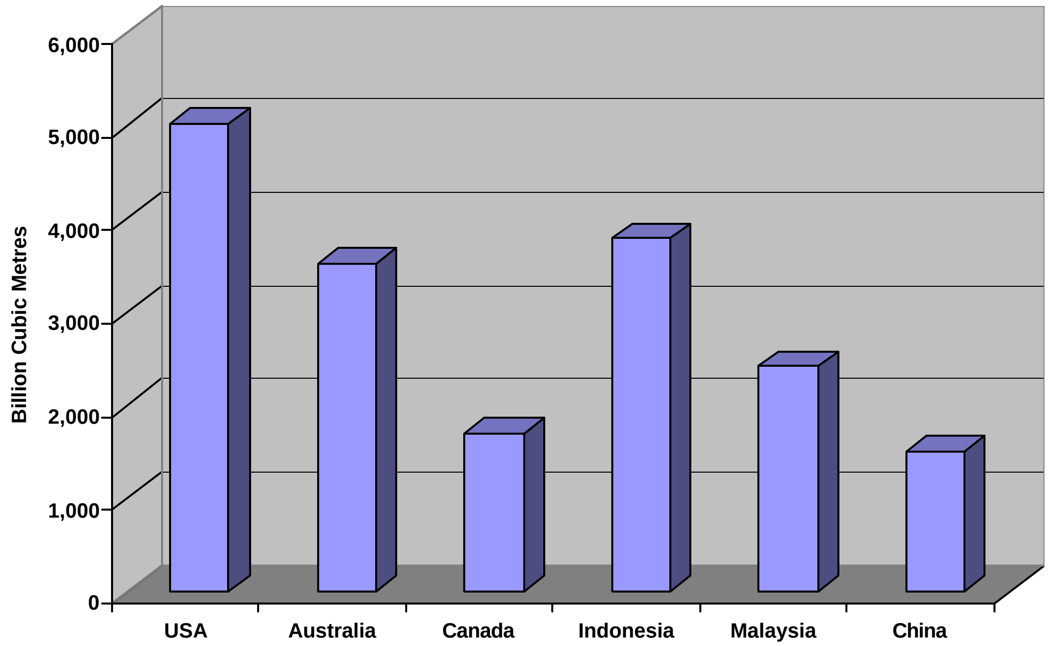
POTENTIAL FOR COMPETITION IN ECONOMIES WITH LARGER GAS RESERVES

Among the APEC economies with relatively large gas reserves, some have gas markets that allow customer choice of suppliers while others have gas markets that are vertically integrated. The group with competitive gas markets includes, in descending order with respect to the size of natural gas reserves, the United States, Australia and Canada. The group with vertically integrated markets, again in descending order by size of gas reserves, includes Russia, Indonesia, Malaysia and China. (Russia is not shown in the chart since with over 48,000 Bcm of reserves, it is far off the scale.)

It is noted above that the United States, with about 5,000 Bcm of gas reserves, and Canada, with around 1,700 Bcm of reserves, have hundreds of competing gas producers each. Indonesia and Malaysia, the two largest APEC gas exporters to Northeast Asia, have about 3,800 Bcm and 2,400 Bcm of gas reserves respectively. In view of the fact that their gas reserves are substantially larger than Canada's, it would seem that they could have quite a number of competing producers on an economical scale. Looking at economies that have vertically integrated monopolies with pricing issues, Russia's gas reserves are more than seven times as large as those of the United States, while China's at 1,500 Bcm are comparable in size to Canada's. So in these economies, too, it would seem that there is scope to have far more competing producers at a cost-efficient scale.

With respect to Indonesia and Malaysia, where many gas resources are offshore, it might be argued that the economies of scale are substantially different than in North America, where most resources have traditionally been on land, making it easier and cheaper for small producers to spring up. But this is more an argument about the degree of competition that might be feasible than about whether competition is feasible at all. If hundreds of producers can compete economically onshore in North America, perhaps only tens of producers could compete economically offshore in Southeast Asia, but that would still be sufficient to foster a competitive marketplace. Indonesia, which has several different offshore fields and several different international oil companies involved in their operation, seems to have recognised this in deciding to implement competitive reforms.

Figure 19 Some APEC Economies with Large Natural Gas Reserves



Source: Cedigaz, as cited in International Energy Agency (2002a)

POTENTIAL FOR COMPETITION IN ECONOMIES WITH SMALLER GAS RESERVES

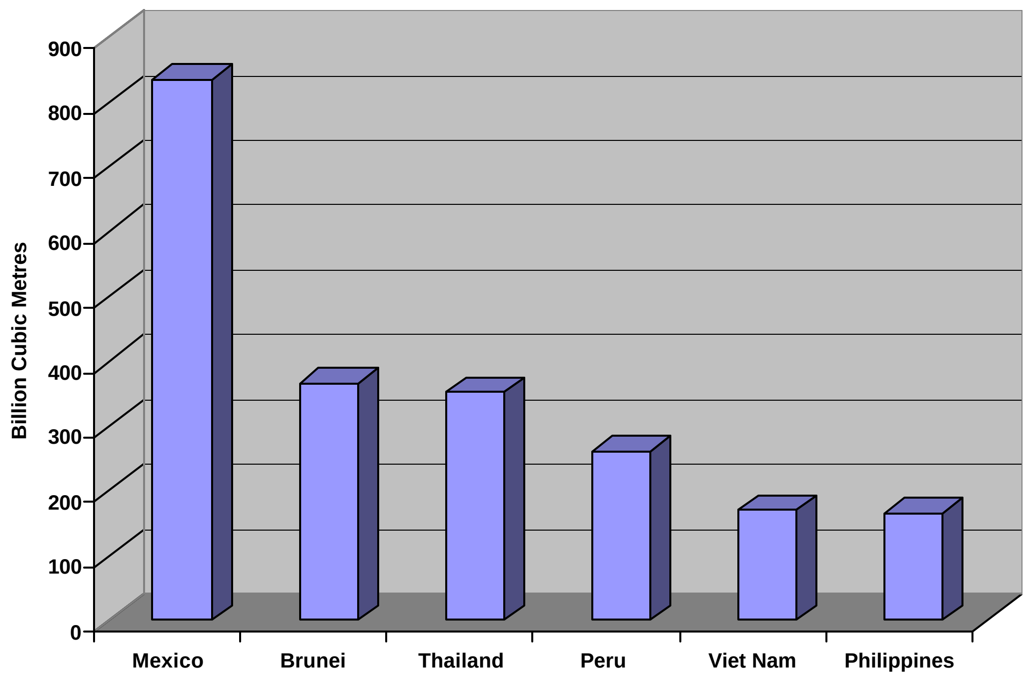
Among APEC economies with smaller gas reserves, most have a substantial degree of integration in their internal gas markets. Three of them, Peru, Viet Nam and the Philippines, have small reserves mainly because development of their gas reserves has been relatively recent. One of them, Brunei Darussalam, is a mature exporter like Indonesia and Malaysia. Another, Mexico, has retained a monopoly on domestic gas production although it allows competition among gas imports. Still another, Thailand, has a significant degree of wholesale competition among gas producers.

For economies that are just beginning to develop their gas reserves, it has been argued, integrated development of production, associated transportation infrastructure and demand may be essential for securing the investment capital that is needed. If it is known in advance that an electric power producer will take the gas under long-term contract, it will be easier for banks to finance production facilities and associated pipelines or LNG terminals. Certainly, this is the model that Peru, Viet Nam and the Philippines have followed in their recent gas market development.

However, it is interesting to note, in this context, that the Philippines are already considering detailed plans for moving toward deregulated production and open access to transportation facilities. According to official proposals circulated in 2002, all suppliers would have access to spare capacity at existing LNG terminals and pipeline facilities, as well as capacity at new facilities, on a non-discriminatory basis. If this is something that can benefit the Philippines, perhaps it might work as well in Peru and Viet Nam, whose gas reserves are of comparable size.

Another interesting example to note is Thailand, which produces about four-fifths of the gas it uses and has increasingly vigorous wholesale competition in its gas market, with several different suppliers. Competing gas producers in Thailand are guaranteed open and non-discriminatory access to transmission facilities. If this is something that is workable in Thailand, there is no inherent reason why it might not also improve the efficiency of gas markets in Brunei Darussalam, whose gas reserves are of similar size, and in Mexico, whose gas reserves are more than twice as large.

Figure 20 Some APEC Economies with More Modest Gas Reserves



Source: Cedigaz, as cited in International Energy Agency (2002a)

OPTIONS FOR PROMOTING GAS MARKET COMPETITION

As detailed above, at least six types of gas markets can be identified in the APEC region. This section offers some options for enhancing competition that could be suited to each market type.

OPTIONS FOR PROMOTING REFORM IN GAS MARKETS WITH CUSTOMER CHOICE

In APEC economies with evolving retail competition and customer choice (Australia, Canada, Chile and the United States), reform efforts with respect to smaller residential and commercial customers are incomplete and have had only a very limited impact. Many states, provinces and territories do not yet allow supplier choice by small gas customers who must purchase gas through local distribution grids. And in many of the places where residential and commercial customers are allowed to choose their gas suppliers, only a small fraction of them have done so.

The reluctance of smaller customers to switch gas suppliers has been due to a variety of factors. For many customers, gas bills may not be a sufficiently large share of business or household budgets to worry about very much, while finding and absorbing information about alternative gas suppliers may be time-consuming. In addition, switching from a traditional supplier to a new supplier without a track record may be seen as risky. Finally, in many areas, little or no effective competition has appeared from alternative retailers. This is often because in order to secure political support for gas market reform, legislators have guaranteed small gas customers attractive regulated "fall-back" rates from traditional suppliers which are hard for competitors to beat.

Under these circumstances, reform efforts in retail markets might be promoted in several ways. Federal governments might encourage additional states, provinces and territories to extend choice among gas suppliers to residential and commercial customers. Where legislation for customer choice is in place, the exercise of choice by customers could be expanded through reliable and unbiased information on competitors' terms and rates, through a simple process for switching suppliers, and through fall-back rates that allow a margin for competitors to enter the marketplace.

OPTIONS FOR REFORM IN GAS MARKETS WITH WHOLESALE COMPETITION

APEC gas-importing economies with wholesale competition, where a single buyer selects gas from various producers, include Japan, Korea, Singapore, Chinese Taipei and Thailand. Since most of these economies import all or almost all their natural gas (the exception is Thailand), it might appear that one of their key options for obtaining gas at more competitive prices would be to diversify their sources of gas supply. Indeed, Japan and Korea have substantially increased the number of different economies from which they import gas over the last two decades. But since economies with vertically integrated gas supplies make up most of the import mix, it will be hard to diversify to more competitive sources of gas unless gas-exporting economies reform their markets.

Another key option for obtaining gas at more competitive prices might be for single buyers to improve their flexibility to take advantage of bargains on the international gas markets when they become available. One way to do this would be to consider a broader portfolio of contract lengths, combined with greater use of the spot market. In the case of Japan, for example, a 10-year contract for Indonesian gas that began in 2000 replaced a 23-year contract that had been in place before. In addition, a five-year contract with Indonesia starts in 2005. Flexibility could also be improved by negotiating contracts that allow for changes in delivery location and reduced take-or-pay amounts.

Ultimately, perhaps the most effective way for economies with wholesale competition in their gas markets to obtain gas more cheaply would be to encourage more aggressive price negotiation by opening up their markets to retail competition. Competing domestic electricity generators or retail suppliers might be granted access to LNG facilities currently controlled by electric or gas utilities. This might mean non-discriminatory access to all capacity at LNG facilities, as has been proposed in Korea, or simply access the portion of LNG facility capacity that is not being used by its owner, as is being considered in Japan. Finally, it might be possible to introduce retail competition so that final customers can choose to buy gas from the supplier who obtains gas at the lowest cost.

REFORM OPTIONS IN GAS MARKETS WITH VERTICALLY INTEGRATED MONOPOLIES

Since four different types of vertically integrated gas market have been identified in this study, different options for reform are outlined below in accordance with their particular situations.

MATURE EXPORTERS WITH VERTICALLY INTEGRATED MONOPOLIES

The major APEC gas-exporting economies with vertically integrated gas markets, namely Brunei Darussalam, Malaysia and Indonesia, have been exploiting their gas resources through a system of production sharing contracts. While a variety of international oil and gas companies have been involved in these contracts, control over production has been retained by a state-owned monopoly.

A conservative approach to gas market reform in such economies might focus on opportunities for enhancing competition within the existing production sharing contract system. For example, a more competitive bidding process for new production sharing contracts might be instituted. This might help ensure that the most efficient and innovative firms are signed on to assist the state monopoly in exploiting gas resources. Alternatively, or in addition, targets might be set for raising efficiency within production sharing agreements that are ongoing. For example, targets might be set for million cubic metres of production per employee per year. Such targets might vary according to the maturity and output trends of different fields. More generally, a target could be set to improve the efficiency of all fields by a certain percentage per year for a certain number of years.

A more aggressive approach to gas market reform in mature exporting economies might be to increase the number of individual entities that are allowed to compete in gas production. One way to increase the number of competing producers could be to split the state-owned monopoly firm into competing divisions, perhaps corresponding to different gas production fields. A further step to promote competition could be to divest the assets of the monopoly firm into competing firms.

Yet another step might be to let private firms produce gas on their own, as recently decided in Indonesia. In any of these cases, for competition in the gas market to be effective, transportation services would have to be provided to all competing producers on a non-discriminatory basis.

RECENT DEVELOPERS WITH VERTICALLY INTEGRATED MONOPOLIES

APEC economies that have recently developed their gas resources through vertically integrated monopoly include Papua New Guinea, Peru, the Philippines and Viet Nam. Typically, these economies have used an identified source of demand, such as electric generating plants, to secure capital for gas production facilities and transportation infrastructure. Simultaneous investment in new gas fields and associated pipelines has also made it easier to obtain financing for each.

In these circumstances, a practical approach to gas market reform might focus on opportunities for enhancing competition once production and transportation facilities are built. One option could be to allow competing firms to produce gas in fields that have already been opened. A more ambitious option, which could be workable in economies whose gas needs are growing fast, would be to accelerate development of new fields by firms other than those in existing fields. To help competing producers evolve, they could be granted non-discriminatory third-party access to the portion of transmission pipeline capacity that is not being used by the incumbent producers.

DOMINANT SUPPLIER WITH COMPETITION AT THE EDGES

APEC economies with dominant gas suppliers include Hong Kong, Mexico, New Zealand and Russia. In these economies, competing gas suppliers are allowed but have only attained a small share of the marketplace. Hence, the key to a more competitive gas market in such economies would seem to be splitting the dominant firm into several competing firms or divisions. In Mexico, whose constitution requires that domestic production be performed by the state, so that effective competition at present comes only from imports, the competing firms or divisions might remain state-owned. Elsewhere, the split might involve divestiture of assets to competing private firms.

Competition could also be enhanced, in such economies, through legislation or regulations to strengthen requirements for non-discriminatory third-party access to gas transportation services. It could be further enhanced through functional separation of transmission from production and distribution from supply, with information firewalls between the functions, so that there is no incentive for the dominant firm to discriminate in favour of its own gas production.

MONOPOLY OR DOMINANT SUPPLIERS WITH TRANSPORT PRICING ISSUES

In China, as noted earlier, incentives for construction of gas transmission pipelines may be weakened, in practice, by caps on gas prices at the city gate. In order to ensure the availability of private capital for needed infrastructure projects, it could be advisable to eliminate such price caps, allowing transport tariffs to be set strictly on the basis of cost and regulated rate of return. Insofar as there might be social concerns regarding the affordability of gas to households, these might be handled through separate income transfers. Since China has three very large vertically integrated gas monopolies operating in parallel, it might also make its gas market more competitive by considering some of the suggestions made above for mature gas exporting economies.

In Russia, as previously described, gas prices paid by domestic industry are far below those that can be obtained for gas exports and may even be below production costs. In this circumstance, incentives are clearly lacking for private capital to improve or expand the domestic pipeline infrastructure as industry grows and requires more gas to be delivered. To help ensure that industry has the gas it needs, it may be advisable to bring gas prices to domestic industry in line with export prices or at least costs of production plus a market-based return. In addition, Russia might look at the options laid out above for markets with a dominant supplier and competition at the edges.

NATURAL GAS MARKET SKETCHES FOR APEC ECONOMIES

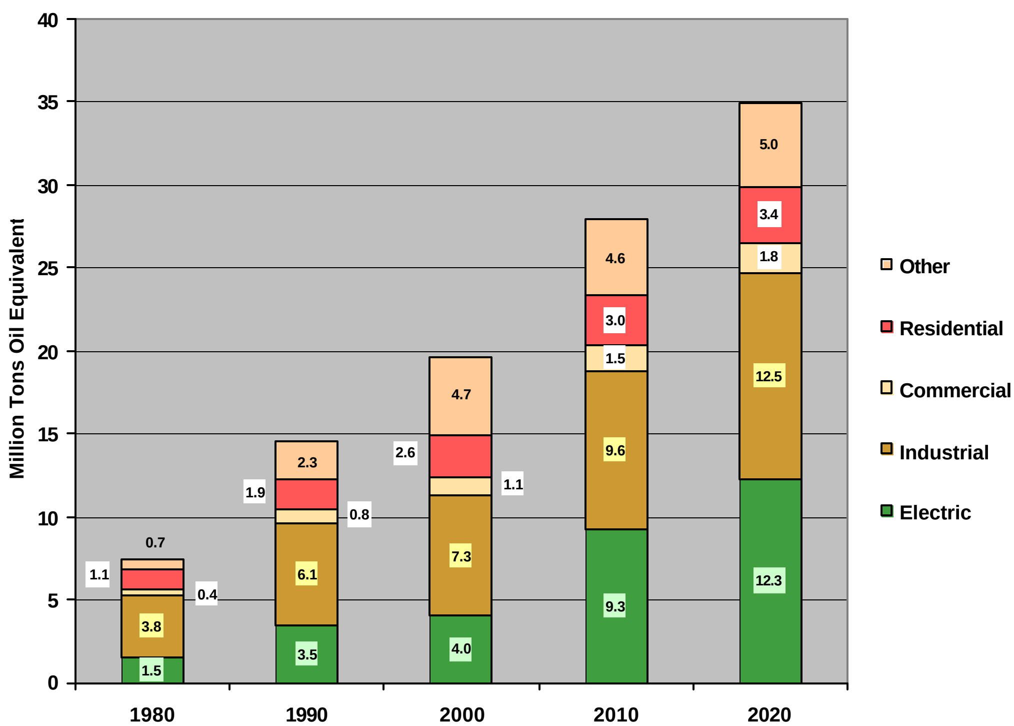
AUSTRALIA

GAS MARKET SETTING[4]

Australia is a major gas producer and exporter, with gas supplied to the economy solely from domestic production.

- Total gas production is projected to more than double from 28.9 Mtoe in 2000 to 65.3 Mtoe in 2020, with the share of exports rising from 32 percent to 47 percent.
- Primary supply of gas to the domestic economy is projected to grow from 19.7 Mtoe in 2000 to 34.9 Mtoe in 2020, with average annual growth of 3.6 percent in the decade from 2000 to 2010 and 2.3 percent in the decade from 2010 to 2020.

Figure 21 Evolution of Natural Gas Use in Australia, 1980-2020



Australia's natural gas use is fairly diversified. Most gas demand is in the electric power and industrial sectors, but substantial gas use occurs in the commercial and residential sectors as well.

- Rapid growth is anticipated in use of gas for electric power generation, with about a tripling of demand from 4.0 Mtoe in 2000 to 12.3 Mtoe in 2020, boosting the electricity sector's share of gas use from 20 percent to 35 percent.
- Industrial gas use is also projected to grow substantially in absolute terms, from 7.3 Mtoe in 2000 to 12.5 Mtoe in 2020, but its share of the overall gas market is projected to decline slightly, from 37 percent to 36 percent.

4 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Commercial and residential gas use will likely grow more modestly, with the commercial share of gas demand settling from 6 percent in 2000 to 5 percent in 2020 and the residential share declining from 13 percent to 10 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Australia has several competing gas producers, all of them private corporations. However, production is still somewhat concentrated. On the eastern coast, Santos, BHP Billiton and Exxon-Mobil account for most production from Australia's central and southeastern gas basins. On the western coast, Woodside Energy, Shell, Chevron and Texaco are the dominant producers in the economy's northwest gas fields, from which most production is exported. There are no gas pipelines connecting Australia's coasts, so there are separate eastern and western gas markets.

PRINCIPAL PLAYERS IN AUSTRALIA'S GAS MARKET

Gas Producers in Australia

BHP Billiton, BP, Chevron, Texaco, Energy Equity Corporation,
ExxonMobil, OMV, Origin Energy, Santos, Shell, Woodside Energy

Owners and Operators of Gas Transmission Pipelines in Australia

Australian Pipeline Trust, CMS Energy, Duke Energy International,
Envestra, Epic Energy, Goldfields Transmission, GPU Gas Net

Owners and Operators of Gas Distribution Pipelines in Australia

Victoria: Envestra, Multinet Gas, TXU Networks (Gas), Vic Gas Distribution
New South Wales: AGL Gas Networks, Country Energy, Albury (owned by Envestra),
Allgas Energy (owned by Energex), ActewAGL Distribution
Australian Capital Territory: Actew/AGL
South Australia: Envestra, Origin Energy
Queensland: Envestra, Allgas, Energex, Origin Energy
Western Australia: AlintaGas
Northern Territory: Origin Energy

Retail Gas Marketers in Australia

Victoria: AGL Victoria, BHP Petroleum, Energex Retail , EnergyAustralia,
Esso Australia Resources, Gascor, Origin Energy Retail, TXU
New South Wales: AGL Retail Energy, Country Energy, Origin Energy,
Allgas Energy (owned by Energex), ActewAGL Retail,
BHP Billiton, Citipower, EnergyAustralia, Integral Energy, Multinet Gas
Australian Capital Territory: Actew/AGL
South Australia: Origin Energy
Queensland: Energex, Origin Energy
Western Australia: AlintaGas
Northern Territory: Origin Energy

Sources: Australian Gas Association; Department of Industry, Tourism and Resources; Independent Pricing and Regulatory Tribunal of New South Wales; Victoria Essential Services Commission

Gas transmission pipelines are regulated by the Australian Competition and Consumer Commission (ACCC) in all states and territories except for Western Australia, where the Office of

Gas Access Regulation has jurisdiction. There are seven different pipeline companies, each of which owns and operates a different portion of the long-distance transmission grid. For instance, Epic Energy owns the Dampier-to-Bunbury pipeline in Western Australia and the Moomba-to-Adelaide pipeline in South Australia. GasNet owns the Principal Transmission System for shipment of gas within Victoria, while the Australian Pipeline Trust owns the Moomba-to-Sydney pipeline that is mainly located in New South Wales. The Eastern Gas Pipeline, owned by Duke Energy, transports gas into New South Wales from southern Victoria. Collectively, these transmission pipelines transport gas from major production areas to major end-use markets.

Gas distribution grids in Australia are regulated by individual states and territories. The distribution function is performed by five different companies in New South Wales, four in Victoria, four in Queensland, and two in South Australia. Less populous Western Australia and Northern Territory, as well as the Australian Capital Territory, have but one gas distributor each. In general, each distribution company operates as a monopoly in a different geographic area. On the other hand, there are ten competing retail gas suppliers in New South Wales, eight in Victoria and two in Queensland, although other parts of Australia still have only one retail supplier each.[5]

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in Australia were effectively unbundled by the National Third Party Access Code to Natural Gas Pipeline Systems (Gas Access Code) that went into effect in 1997 pursuant to the Gas Pipelines Access Law. South Australia was the first jurisdiction to implement the Code, with other states and territories following. Ownership of gas production facilities is completely separate from ownership of transportation and distribution facilities. While two major gas companies have both transmission and distribution assets, and while most gas distribution companies also have retail supply businesses, the Gas Access Code requires that transmission, distribution and retail supply be functionally separated by "ring fences". This means that each function must be carried out by a distinct legal entity (that is, a distinct corporate division), and there are restrictions on exchange of information between them.

Third-party access to Australia's gas transportation and distribution grids is provided on a negotiated basis. In the case of companies covered by the Gas Access Code, which applies to almost all major gas transmission pipelines and the distribution networks in major cities, surplus pipeline capacity is offered to third parties in accordance with terms and conditions approved by the regulator. Owners of smaller distribution networks that are not covered by the Gas Access Code can choose whether they offer access to all producers and suppliers on a non-discriminatory basis.[6] The Eastern Gas Pipeline, an unregulated transmission pipeline, claims to do so as well.[7]

LNG facilities, which are used for gas exports, are not regulated as pipelines since they involve gas processing. The Gas Pipelines Access Law provides that any equipment used to modify natural gas, including processing plants, is not defined as a pipeline. Thus, it is unlikely that a third party could seek access to LNG export facilities under the Gas Access Code.[8]

MARKET MODEL AND COMPETITION

Australia would seem most closely to fit the retail competition model. The most heavily populated states allow all customers to choose their gas supplier. New South Wales and the Australian Capital Territory have done so since January 2002, while Victoria has done so since October 2002. Most other states provide retail choice to industrial and commercial customers. South Australia does so for all such customers, Western Australia for those consuming more than 1

---

5 Department of Industry, Tourism and Resources (2002). Actew AGL (2002). AlintaGas (2002). Country Energy (2002). Energex (2002). EnergyAustralia (2002). Envestra (2002). Origin Energy (2002). TXU (2002). Independent Pricing and Regulatory Tribunal of New South Wales (2003). Victoria Essential Services Commission (2003).

6 Department of Industry, Tourism and Resources (2002). Gas Reform Implementation Group (2002).

7 Duke Energy (2003).

8 Gas Pipelines Access (South Australia) Act 1997, schedule 1, definitions.

terajoule (TJ) per year and Queensland for those using at least 100 TJ per year. South Australia and Western Australia are giving all customers a choice of gas suppliers as of October 2003.[9]

While major new retail companies have not so far formed, most distribution companies have retail supply arms, of which there are several in Victoria and New South Wales. So at least in densely populated areas, potential for effective retail competition appears to be present. In New South Wales and the Australian Capital Territory, roughly 24,000 out of 1 million customers changed their gas suppliers during the first ten months that retail competition was in effect, representing 2.4 percent of all customers. In Victoria, some 7,500 out of 1.4 million customers, or 0.5 percent of all customers, changed suppliers during the first six weeks of retail choice.[10] But the number of competing gas producers is limited, and competition among them is hampered by the long-term supply contracts that were left intact when the Gas Code was introduced. It is anticipated that the gas market will become more dynamic and competitive as existing contracts expire, new producers enter the upstream market, and expanding pipeline interconnections allow more suppliers to reach customers, particularly in the southeast where the grid is most extensive.[11]

There is little vertical integration in Australia between gas transmission and power markets. No gas transmission pipelines are controlled by vertically integrated electric utilities or power producers. Only one of the seven transmission pipeline owners, Envestra, has distribution assets, and it does not engage in competitive retail supply. Two independent power producers, TXU and International Power, are building a gas pipeline from the Otway Basin in southwest Victoria to Adelaide in South Australia to provide gas for electricity generation. However, interested parties such as potential competitors in the power market could nominate this pipeline for coverage under the Gas Access Code. If an appropriate minister decides that a pipeline should be covered by the Code pursuant to a recommendation by the National Competition council, the owners would propose an access arrangement for approval by the Australian Competition and Consumer Commission (ACCC) that would allow third parties to negotiate access to the pipeline with arbitration of any access disputes.[12]

On the other hand, there is growing convergence of gas and electricity markets at the level of distribution and retail supply. Almost all the major gas distribution companies also own electric distribution lines and have retail arms that market both gas and electricity to final customers. Some of these companies, like Energy Australia and Great Southern Energy, were traditionally electric companies that are moving into gas markets. Others, like Energex and Origin Energy, started out as gas companies but are expanding into power markets.[13] There could be significant efficiencies from consolidation of retail functions like billing and metering for both kinds of energy in the same firm. If ring fencing of distribution from retail arms is effectively enforced, so that all competing retailers can obtain the gas and power they need to serve customers, such consolidation should not have adverse consequences for the efficiency of energy supply in either gas or electric markets.

PRICE TRENDS

Australia's gas prices were stable or declining during most of the 1990s. Household gas prices increased by about a quarter in real terms between 1985 and 1991 (from $270 to $343 per tonne oil equivalent in 2000 US$) but were only slightly higher in 1997 ($348 per toe) than in 1991. Industrial gas prices increased by about one-fifth in real terms between 1985 and 1991 (from $135 to $162 per toe) but had reversed most of their gain by 1997 (when they were $142 per toe).[14]

---

9 Department of Industry, Tourism and Resources (2002).

10 Government of Western Australia (2003), page 2.

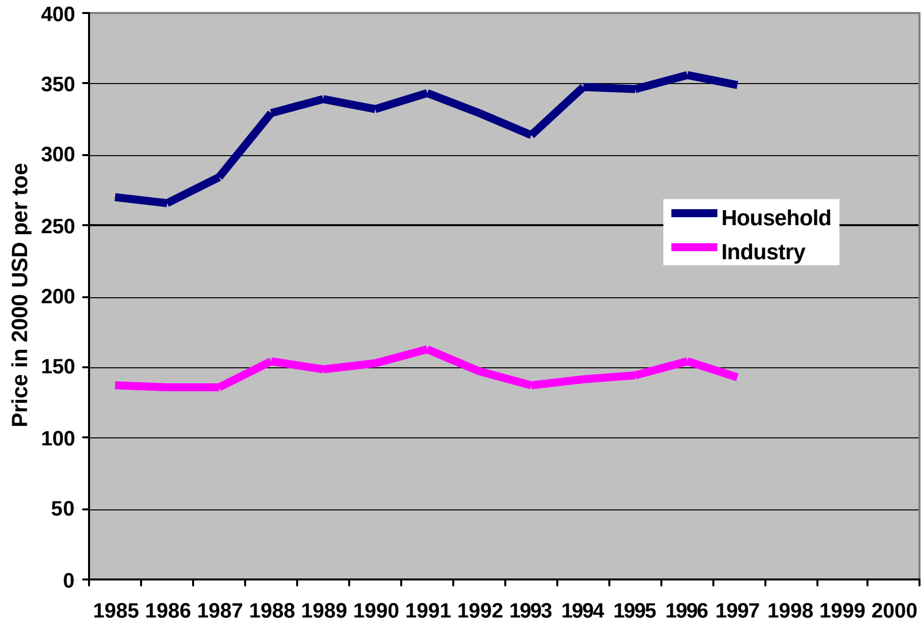
11 Dimasi (2003), pages 4, 9-11.

12 Department of Industry, Tourism and Resources (2002).

13 Energex (2002), EnergyAustralia (2002), New South Wales Treasury (1998), Origin Energy (2002).

14 International Energy Agency (1997) pages II.19-21, IEA (2002a) pages III.30-32. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

Figure 22 Natural Gas Prices in Australia, 1985-1997



Source: International Energy Agency, US Department of Commerce

According to one study, gas prices for industrial and residential gas consumers in Australia fell by an average of 22 per cent between 1994 and 1998 in real national currency terms.[15] But perhaps the best available evidence of the impact that market reforms have had on gas prices in Australia is to be found in Victoria, which was one of the first states to reform its gas market at the retail level. For business customers, whereas real gas prices fell by 8 percent between 1991-92 and 1996-97, they declined for small businesses by 30 percent between July 1996 and January 2001. For household customers, whereas real gas prices increased by 7 percent in the earlier five-year period, they fell by 11 percent in the latter five-year period.[16]

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Australia had about 19,400 km of gas transmission pipeline and 73,300 km of gas distribution pipeline in service in 2001.[17] The main gas transmission grid connects producing and consuming areas in Victoria, New South Wales, the Australian Capital Territory, South Australia, Queensland and Tasmania. Separate transmission grids exist in the Northern Territory and in Western Australia; there are proposals to link the former with the main grid. LNG terminals are used to export gas, mainly to Japan but also in smaller amounts to Korea and the United States.

Substantial investments are anticipated to augment the Australian gas transmission grid in coming years. For example, Origin Energy, International Power and TXU Australia are building an Aus$500 million pipeline from Port Campbell, Victoria to Adelaide, South Australia to begin operation in 2004. Epic Energy has proposed a pipeline from the northern port of Darwin to

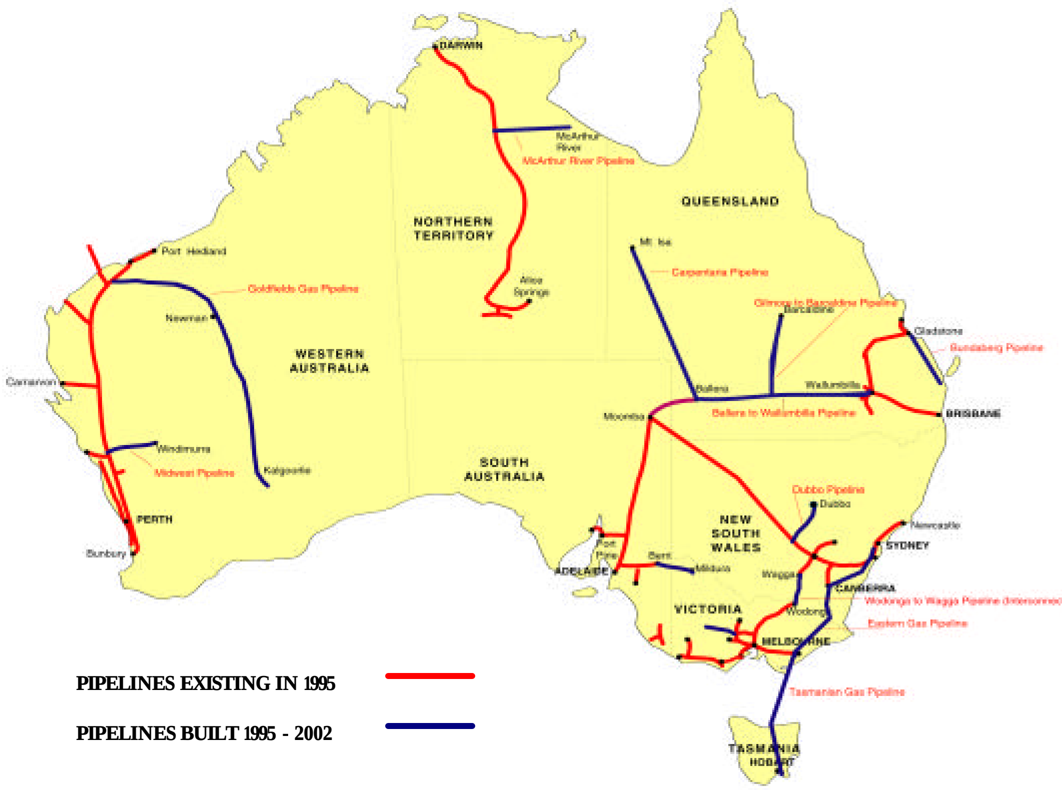
15 Dimasi (2003), page 5. NUS International (1999). Australian Gas Association (2001) reports that the weighted average cost of gas declined from Aus$10.21 to Aus$9.48 per gigajoule, or about 7 percent in nominal terms, over this period.

16 Office of the Regulator General, Victoria (2001). Productivity Commission (1998).

17 ABARE (2002). Australian Gas Association (2001).

southeastern Australia in the event that gas is brought onshore from the Timor Sea, which it estimates will cost some Aus$1.5 billion. In all, some 8,700 km of new gas transmission pipelines with an estimated cost of Aus$6.2 billion have been proposed.[18]

Figure 23 Expansion of Australia's Natural Gas Pipeline Network, 1995-2002



Source: Dimasi (2003)

The gas distribution network in Australia is well developed, at least in major urban areas. The service areas of distribution and retail companies cover most of the heavily populated coastal areas. Rural inland areas do not usually have gas distribution networks, but transmission and distribution pipelines are built to serve regional markets when appropriate business plans can be developed.

INFRASTRUCTURE INVESTMENT INCENTIVES

Investment decisions on the extension of high-pressure transmission pipelines are taken on a commercial basis, without financial support from the government. Under the Gas Access Code, pipelines that existed at the time of its enactment are automatically covered by incentive rate regulation. A new pipeline may become subject to incentive rate regulation if a party applies to have it covered by the Code and an appropriate government minister agrees. Alternatively, a pipeline may voluntarily lodge its own access arrangement or undertaking with the ACCC. Until such time, it is assumed that the threat of regulation will provide an incentive for the pipeline owner to negotiate fairly with suppliers, retailers and customers for use of the pipeline. Under the regulatory framework, efficiency incentives are offered which allow pipeline owners to exceed the ACCC benchmark rate of return by reducing capital and operating costs below forecast levels.[19]

---

18 SEA Gas (2002). Epic Energy (2000). ABARE (2002).

19 Dimasi (2003), pages 11-13.

The Gas Code allows the ACCC to set a higher regulated rate of return for greenfield pipelines than for established pipelines, in recognition of the higher risks involved. Post-tax regulated rates of return, based on the weighed average cost of capital, have been around 12 to 13 percent in recent years for established gas pipelines, whereas a rate of 15.4 percent has been allowed for a greenfield pipeline. Nonetheless, industry has claimed that the regulatory regime is hampering investment in greenfield pipelines, and the government is planning to review the Gas Access Code to see if there are merits to the claims and how the code might be modified to address them.[20]

To judge by recent history, the incentives for construction of new transmission infrastructure appear to be very good. In just twelve years, the high-pressure pipeline grid almost doubled in length from 9,000 km in 1989. Over the four-year period from 1995-96 through 1999-2000, which immediately followed major gas market reforms, capital expenditure for transmission assets averaged Aus$330 million per year. This was roughly seven times the pace between 1989-90 and 1993-94, just prior to gas market reforms, when the average was just Aus$46 million annually.[21]

The quickened pace of transmission grid expansion has not only enhanced opportunities for competition among gas suppliers, as indicated by the price trends discussed above, but has also apparently improved supply security by increasing the transmission system's flexibility. In 1998, Victoria's main source of gas supply was cut off following an explosion at the Longford reprocessing plant. However, it was possible to continue supplying gas for hospitals and other essential services through a new pipeline interconnection that had just been completed.[22]

Investment decisions on extension of distribution networks are also made on a commercial basis in most cases. Most current extensions are being made in new suburban developments and are subject to approval by local planning authorities. The Victoria government has announced a policy to assist in the extension of the distribution grid to several new towns.

---

20 Department of Industry, Tourism and Resources (2002).

21 Australian Gas Association (2001) and previous issues.

22 Dimasi (2003), page 8.

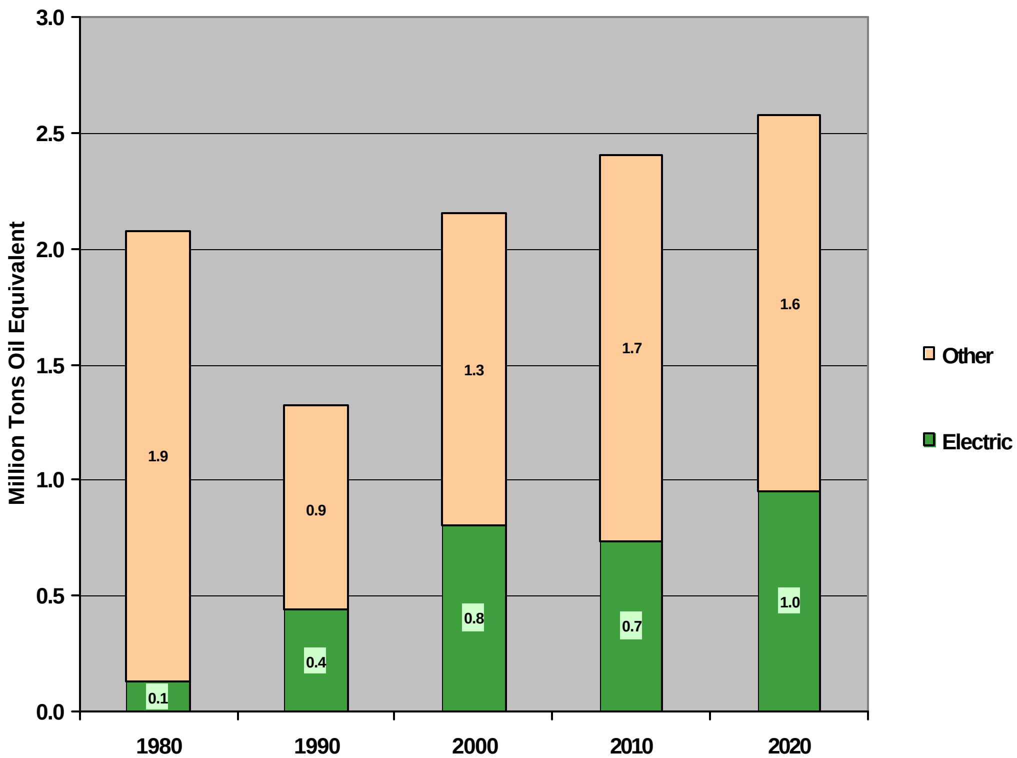
BRUNEI DARUSSALAM

GAS MARKET SETTING[23]

Brunei Darussalam is a significant gas producer and exporter, with domestic production satisfying all of the economy's gas supply requirements.

- Total gas production is projected to increase from 9.5 Mtoe in 2000 to 15.1 Mtoe in 2020, with the share of exports growing from 77 percent to 83 percent.
- Primary supply of gas to the domestic economy is projected to grow from 2.15 Mtoe in 2000 to 2.57 Mtoe in 2020, with average annual growth of just 1.1 percent in the decade from 2000 to 2010 and 0.7 percent in the decade from 2010 to 2020.

Figure 24 Evolution of Natural Gas Use in Brunei Darussalam, 1980-2020



All of Brunei Darussalam's natural gas use is devoted to production of oil, gas and electric power. There is virtually no use of natural gas in the downstream industrial, commercial or residential sectors.

- Use of gas in the electric power sector is expected to grow very modestly, from 0.8 Mtoe in 2000 (a 38 percent share) to 1.0 Mtoe in 2020 (a 37 percent share).[24]

---

23 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

24 Petroleum Unit (2002a) presents quite a different picture, in which total natural gas demand expands from 1.57 Mtoe in 2000 to 3.42 Mtoe in 2010 and 5.03 Mtoe in 2020, use of gas in the electric power sector grows to 1.52 Mtoe in 2010 (with a 44 percent share of demand) and 2.03 Mtoe in 2020 (with a 40 percent share), and downstream industrial use of gas grows from a negligible base in 2000 to 1.0 Mtoe in 2010 (29 percent share) and 2.1 Mtoe in 2020 (42 percent).

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

About 90 percent of Brunei Darussalam's gas is produced by Brunei Shell Petroleum, an equal joint venture of the Asiatic Petroleum Company in the Royal Dutch/Shell group and the government. The rest of the economy's gas is produced by the Block B Joint Venture of Shell Deepwater Borneo in the Royal Dutch/Shell group, the government and Total.

The bulk of Brunei Darussalam's gas is exported as LNG through terminals owned by Brunei LNG, a joint venture of the government (which has a 50 percent share) with Royal Dutch Shell and Mitsubishi (which each have 25 percent shares). About 88 percent of the economy's LNG exports go to Japan, and the rest go mainly to Korea. A small amount of LNG was exported to Spain and the United States for the first time in history in 2002.[25] Within Brunei Darussalam, gas not used in oil and gas production is transported to electric power plants by Brunei Shell Petroleum.

There is little regulation of the gas industry as the state retains a key role in all phases of its operation. PetroleumBrunei, a state-owned firm set up in 2002 to manage production sharing contracts for exploration and production of oil and gas, also regulates the oil and gas industries. It assumed the regulatory role of the Brunei Oil and Gas Authority, which was abolished.[26]

PRINCIPAL PLAYERS IN BRUNEI DARUSSALAM'S GAS MARKET

Gas Producers in Brunei Darussalam

Brunei Shell Petroleum (owned half by the government and half by Asiatic Petroleum Company within the Royal Dutch/Shell group), Block B Joint Venture (owned 27.5 percent by the government, 37.5 percent by operator Total and 35 percent by Shell Deepwater Borneo Ltd)

Owners and Operators of Gas Transmission Pipelines in Brunei Darussalam

Brunei Shell Petroleum, Block B Joint Venture

Owners and Operators of Gas Distribution Pipelines in Brunei Darussalam

Brunei Shell Petroleum

Owner and Operator of LNG Facilities in Brunei Darussalam

Brunei LNG (owned 50 percent by the government, 25 percent by Shell Petroleum N.V. and 25 percent by Mitsubishi Corporation)

Sources: Asia Trade Hub, IEEJ, Petroleum Unit

UNBUNDLING AND THIRD PARTY ACCESS

The functions of Brunei Darussalam's gas market are not unbundled to any significant extent. Brunei Shell Petroleum, which accounts for 90 percent of production, also controls the bulk of facilities for transmission and distribution of gas in the domestic market. Brunei LNG, which has all facilities for gas exports, has largely the same ownership as Brunei Shell Petroleum, since the government has a 50 percent stake in both firms and the Royal Dutch/Shell Group is also present in both. There are no legal or regulatory provisions in place that would require the two incumbent producer-transporters of gas to grant competing producers access to their pipelines.

[25] Wybrew-Bond (2002), page 297. Petroleum Unit (2002a).

[26] National Chamber of Commerce (2002).

MARKET MODEL AND COMPETITION

Brunei's gas market most closely resembles the vertically integrated monopoly model. Brunei Shell Petroleum, which is owned half by the government and half by Royal Dutch/Shell, controls 90 percent of the economy's gas production and transportation. The Block B Joint Venture, also with majority ownership by the government and Royal Dutch/Shell, controls the remaining gas production and transportation in the domestic market. Production, transmission and distribution of almost all the gas used in the economy are thus effectively integrated into a single partnership.

Brunei's gas market is also vertically integrated with its electricity market. Over 99 percent of the economy's electric generating capacity is gas-fired. Depending upon the area, all power is produced and transported by either the Department of Electrical Services (DES) in the Ministry of Development or the Berakas Power Company (BPC) which is also government-owned.[27] DES and BPC can buy gas only from Brunei Shell Petroleum, which conversely has no customers in the domestic market but DES and BPC. The situation in each area thus approaches a bilateral monopoly-monopsony in which Brunei Shell Petroleum could well negotiate increased gas prices to DES or BPC to cover inefficiencies that might arise in gas production, processing, or transportation. DES or BPC could then pass on the resulting increase in generating costs in its rates to electricity customers, who have no other source of power. If power producers negotiate favourable gas prices, they may not pass on all the cost savings in reduced rates to electricity users.

PRICE TRENDS

Natural gas is sold by producers to Brunei LNG at a prevailing market "into plant" price which has recently been around US$2 per million Btu (MBtu), or roughly US$79 per tonne oil equivalent. Brunei LNG then sells liquefied natural gas for export at a market-based price, which was about US$4.40 per MBtu or US$175 per toe in 2001. Natural gas prices for domestic industrial consumers are substantially lower, ranging from US$0.80 per MBtu to the "into plant" market price of US$2 per MBtu, or roughly from US$32 to US$79 per toe. Natural gas prices for most electricity production, which are negotiated between the gas producer and the government, are also substantially below the export price. Small residential and commercial consumers, who do not generally have access to the natural gas network, can buy liquefied petroleum gas (LPG) in cylinders at much higher prices of B$415 to B$423 per cubic metre or about US$368 to US$375 per toe.[28]

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Brunei Darussalam had about 336 km of gas transmission pipeline and 661 km of gas distribution pipeline in service in 2001. Another 75 km of transmission pipelines were planned, in part to deliver gas from new offshore platforms between late 2003 and 2005. The transmission and distribution infrastructure necessary to deliver gas to domestic power producers can be expected to expand gradually as gas-fired power generation grows. But there are no plans to extend a natural gas distribution grid to residential or commercial customers since space heating requirements are negligible, other fuels are used for cooking, and air conditioning is readily powered by electricity.

A vital component of the gas transportation infrastructure in Brunei is comprised of facilities for LNG exports, mainly to Japan and Korea. The existing LNG terminal, from which exports began in 1972, has a capacity of 7.2 Mt per annum. Since current annual production of roughly 6.7 Mt is approaching the capacity limit, there are plans to upgrade the facilities and to build a new

[27] IEEJ (2002a), page 111.

[28] Petroleum Unit (2002a). For natural gas, conversions from prices per MBtu to prices per toe assume a conversion factor of 39.68 MBtu per toe from IEA (2002a). For LPG, conversion from price per cubic metre to price per toe assumes conversion factors of 1.844 cubic metres per tonne LPG and 1.13 toe per tonne LPG from IEA (2001) and a currency conversion rate of 1.84 Brunei dollars per US dollar per prevailing exchange rates in early 2003.

LNG train with 4 Mt per annum of additional capacity by 2008. There are also plans to extend the operating life of the terminal by 20 years through 2033. Estimated investment requirements by Brunei LNG for completion of these projects are B$2.4 billion (US$1.3 billion) through 2016.[29]

INFRASTRUCTURE INVESTMENT INCENTIVES

Brunei Darussalam's domestic natural gas prices appear to be substantially below those that would occur in a competitive marketplace. Regulated prices for gas use by industrial customers are as little as two-fifths of the price at which gas is sold to Brunei LNG for export and one-fifth of the export price of LNG itself. The regulated price for gas use in electricity production is even lower, representing even smaller fractions of the sales price to Brunei LNG and the LNG export price.

In view of these price differences, incentives for investment in transmission and distribution infrastructure for domestic gas use would appear to be much less attractive than those for investment in pipelines and LNG facilities for gas exports. However, under existing arrangements with Brunei Shell Petroleum, almost all costs for expansion of domestic infrastructure are borne by the government. Hence, the direct impact of these weak incentives is probably limited.

[29] Petroleum Unit (2002a and 2002b). IEEJ (2002a), page 107. Wybrew-Bond (2002), page 297.

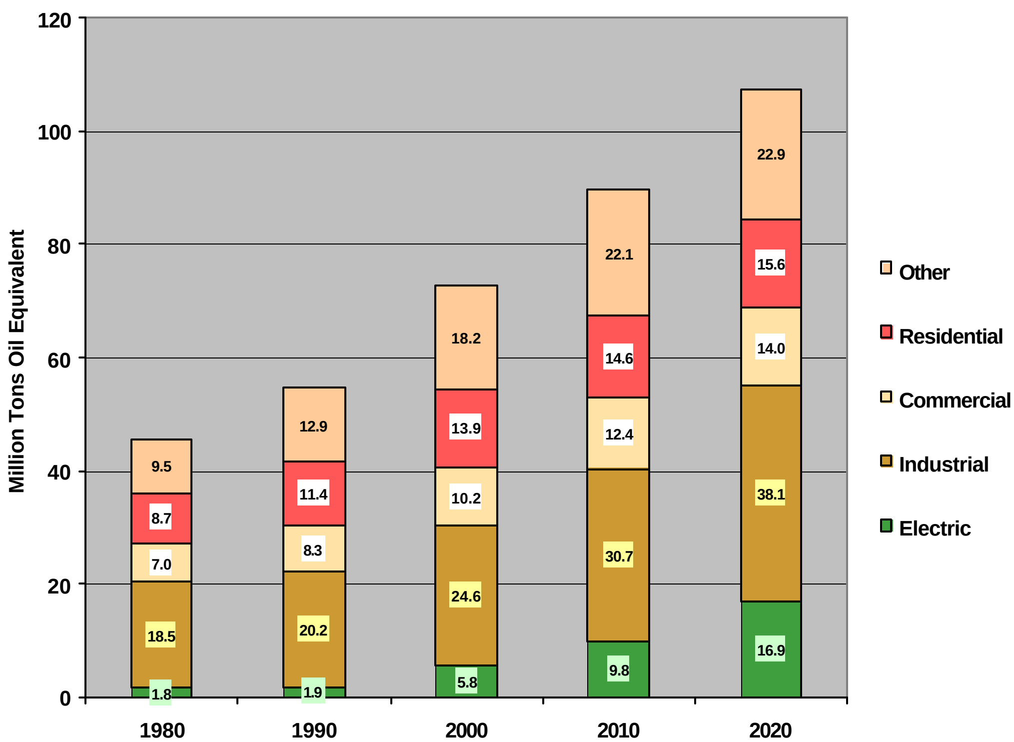
CANADA

GAS MARKET SETTING[30]

Canada is the world's third-largest producer and second-largest exporter of gas, with gas supplied to the economy almost entirely from domestic production.

- Total gas production is projected to increase by more than half, from 153 Mtoe in 2000 to 236 Mtoe in 2020, with net exports as a share of production growing slightly from 53 percent to 54 percent.
- Primary supply of gas to the domestic economy is projected to grow by nearly half, from 73.0 Mtoe in 2000 to 107.4 Mtoe in 2020, with modest yearly demand growth of 2.1 percent from 2000 to 2010 and 1.8 percent from 2010 to 2020.

Figure 25 Evolution of Natural Gas Use in Canada, 1980-2020



Canada's natural gas use is well diversified, with about a third of gas demand in the commercial and residential sectors, a third used in the industrial sector, and another third consumed in production of oil, gas and electricity.

- The fastest growth in gas use is expected to occur in the electric power sector, with about a tripling of demand from 5.8 Mtoe in 2000 to 16.9 Mtoe in 2020, nearly doubling the sector's share of overall gas use from 8 percent to 16 percent.

[30] Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

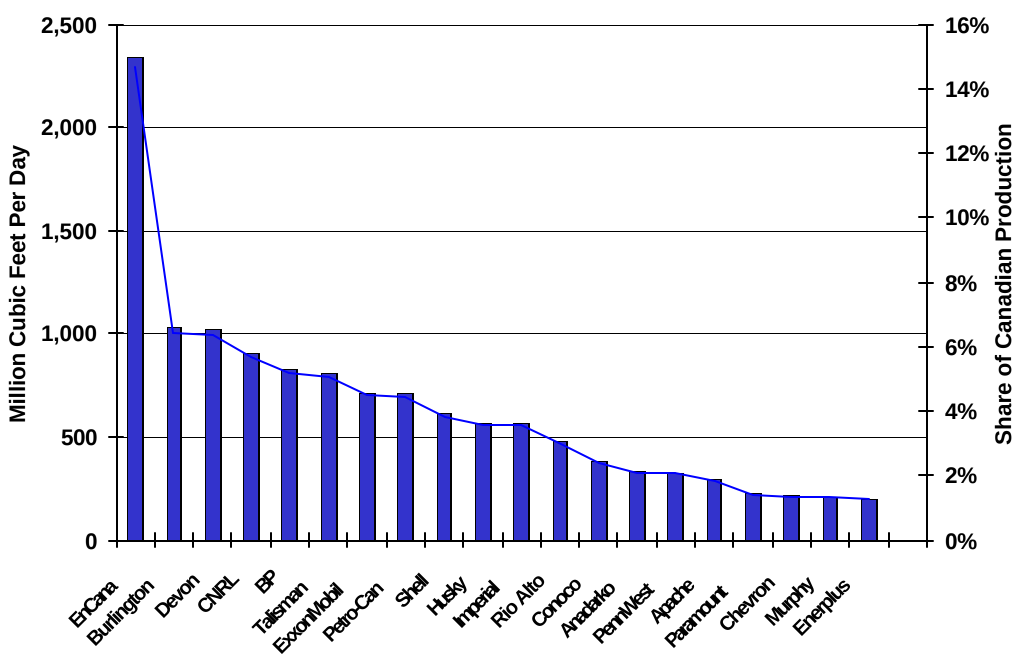
- Industrial gas use is projected to grow even more than power sector gas use in absolute terms, from 24.6 Mtoe in 2000 to 38.15 Mtoe in 2020, with the industrial share of overall gas demand increasing slightly from 34 percent to 35 percent.
- Commercial and residential gas use are projected to grow more slowly, with the commercial share of gas demand declining slightly from 14 percent in 2000 to 13 percent in 2020 and the residential share declining noticeably from 19 percent to 15 percent over the same period.[31]

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

There are many competing gas producers in Canada. In 1985, just prior to gas market reforms, the top 10 producers accounted for 47.6 percent of production, the top 20 for 64.4 percent, and the top 100 for 90.1 percent. Ten years later, the market was somewhat less concentrated, with the top 10 firms producing 40.4 percent of the gas, the top 20 producing 59.4 percent and the top 100 producing 87.6 percent. But by 2001, the market was somewhat more concentrated than it had been before reform, with the top 10 producers accounting for 56.6 percent of output, the top 20 for 76.0 percent and the top 100 for 90.2 percent. Still, as the National Energy Board has noted, "no one company or group of large companies has an inordinate influence on the market. Supplies are available from hundreds of companies, all of which compete for their share of gas markets."[32]

Figure 26 Market Shares of the Top Twenty Canadian Gas Producers in 2000



Source: National Energy Board

[31] Natural Resources Canada (2002) presents a slightly different picture, with the electric power share of gas demand growing even faster, from 10 to 23 percent (instead of from 8 to 16 percent), the industrial share declining from 32 to 29 percent (instead of increasing from 34 to 36 percent), the commercial share declining from 14 to 10 percent (instead of from 14 to 12 percent) and the residential share declining from 20 to 13 percent (instead of from 19 to 14 percent).

[32] National Energy Board (1996), pages 5-6.

PRINCIPAL PLAYERS IN CANADA'S GAS MARKET

Gas Producers in Canada

Note: The largest producers are listed in order of 2000 market share; there are hundreds of producers in all.
EnCana, Burlington Resources Canada, Devon Energy, Canadian Natural Resources Ltd, BP Canada Energy, Talisman Energy, ExxonMobil Canada, Petro-Canada, Shell Canada, Husky Energy, Imperial, Rio Alto, Conoco, Anadarko, PennWest, Apache, Paramount, Chevron, Murphy, Enerplus

Owners and Operators of Gas Transmission Pipelines in Canada

British Columbia: Westcoast Energy (owned by Duke Energy Gas Transmission Canada); shorter pipelines operated by TransCanada, Foothills, Alliance
Alberta: TransCanada-Alberta
Saskatchewan: TransCanada, TransGas (owned by provincial government, related to SaskEnergy)
Manitoba: TransCanada
Ontario: TransCanada, Union Gas, Vector
Quebec: TransCanada, Champion (GMi-owned), TransQuebec & Maritimes (half GMi-owned)
Atlantic Provinces: Maritimes and Northeast Pipeline

Owners and Operators of Gas Distribution Systems in Canada

British Columbia: BC Gas Utility and its subsidiary Centra Gas British Columbia, Pacific Northern Gas (owned by Duke Energy)
Alberta: ATCO Gas (80% of market), AltaGas, 69 rural cooperatives, 24 municipal utilities
Saskatchewan: SaskEnergy (owned by provincial government)
Manitoba: Centra Gas Manitoba (owned by Manitoba Hydro)
Ontario: Union Gas, Enbridge Gas Distribution, Westcoast Energy
Quebec: Gaz Métropolitain (97% of market), Gazifère
Atlantic Provinces: Enbridge Gas New Brunswick; Heritage Gas Limited, Nova Scotia

Retail Gas Marketers in Canada

British Columbia: Several marketers serving large industrial and commercial customers
Alberta: Eight marketers serving large industrial and commercial customers; of these, ENMAX Energy and EPCOR Energy Services also have residential customers
Saskatchewan: SaskEnergy (owned by provincial government)
Manitoba: Centra Gas Manitoba, Energy Savings Corporation, Municipal Gas Manitoba
Ontario: Alliance Gas Management, Direct Energy, Ontario Energy Savings Corporation, Enbridge Services, Nexen Marketing, Union Energy, about 20 others
Quebec: Gaz Métropolitain, Coral Energy Canada, ECNG, GCP Energie, Nexen, many others
New Brunswick: Enbridge Atlantic Canada, GasCo Energy, Irving Energy Services, Park Fuels, WPS Energy Services

Source: National Energy Board (1996, 2002).

With respect to long-distance gas transportation for the Canadian market, there are major players in both Canada and the United States. The most extensive transmission pipeline is owned by the TransCanada Pipeline Company. It begins at production sites in Alberta, branching west to British Columbia and east through the plains of Saskatchewan and Manitoba to populous Ontario and Quebec. The TransCanada pipeline, which is regulated as a natural monopoly by the federal government, is linked to various provincial pipelines, which are generally oriented from north to south and regulated as natural monopolies by provincial governments. Quebec has two provincial pipelines and British Columbia has four, but one is dominant in each case in terms of both geographic extent and market share, and each serves a geographically distinct area. There are major pipelines (Westcoast, Foothills and Alliance) linking Canadian producers with the Western and Midwestern markets of the US, as well as a major pipeline (Vector) linking the US Midwest with gas marketers and customers in Ontario. As a result, the US and Canadian markets are inextricably linked, and supply or price trends in one may influence those in the other.

Gas distribution grids are also regulated by the provinces, but the organisation of these grids is quite varied. In Saskatchewan, Manitoba and New Brunswick, there is a single owner and operator for the distribution grid throughout the province. In Quebec, there are two companies with distribution assets, but one controls almost the entire market. There are two companies with a substantial share of the distribution grid in Ontario and three in British Columbia. In Alberta, while a single distribution company (NOVA) holds 80 percent of the market, it shares the market with another investor-owned utility, 24 municipal utilities, and 69 rural cooperatives.[33]

Most notably, there is a proliferation of competitive retail gas marketers throughout Canada. There are multiple marketers in every province that consumes significant amounts of gas. Large industrial and commercial firms have been most active in choosing among competing marketers. However, residential consumers are also entitled to choose their suppliers, and substantial numbers have done so in Alberta and Ontario, which are Canada's two largest gas-consuming provinces. In Alberta, two of eight licensed retailers are actively marketing to residential consumers. In Ontario, there are about 25 licensed gas marketers from which residential customers may choose.

UNBUNDLING AND THIRD PARTY ACCESS

In Canada's gas market, production is almost entirely unbundled from transmission. The two functions are always performed by separate business entities, and very few producers have financial interests in transmission pipelines. Natural gas commodity prices in Canada were deregulated by the 1985 Agreement on Natural Gas Prices and Markets between the federal government and the provinces of Alberta, British Columbia and Saskatchewan. There are dozens of competing gas producers in the Western Canadian Sedimentary Basin where most of the economy's gas originates. In the newly developed Scotian Shelf off the Atlantic shorelines of New Brunswick and Nova Scotia, however, there are not yet competitors to the Sable Offshore Energy Project.[34]

Long-distance gas transmission in Canada has often been separate from local gas distribution. In British Columbia, Alberta, Manitoba, and the Atlantic Provinces, there is ownership unbundling; gas transmission pipelines and distribution systems are owned by different entities. But in Saskatchewan, Ontario and Quebec, major portions of the transmission and distribution networks have common owners. Since transmission and distribution are both common carriers of gas, there is no economic necessity or legal requirement for functional separation between the two.

The 1985 Agreement and the National Energy Board Act ensure regulated third-party access to the gas transmission network. TransCanada and other pipeline companies were required to functionally unbundle their transmission and marketing activities, with information firewalls between them. Gas producers could then compete for the business of power producers and large industrial customers that connect directly to the transmission grid. Subsequently, most provincial governments unbundled the distribution and marketing functions of local distribution companies. This allowed the emergence of a large number of retail gas marketers that arrange for supply of gas from competing producers to smaller residential and commercial customers.

MARKET MODEL AND COMPETITION

Canada would seem most closely to fit the retail competition model. Many large industrial firms and electricity generators have been able to buy gas directly from producers. Every province with a gas market of any significance has multiple retail marketers offering gas to smaller customers, who may also buy directly from producers if they wish. So in principle, all consumers have a choice

[33] National Energy Board (2002), pages 4-5, 14, 18, 22, 27, 32, 35.

[34] The Sable project was developed by a consortium of Mobil Oil Canada Properties (50.8%), Shell Canada Ltd (31.3%), Imperial Oil Resources (9.0%), Nova Scotia Resources Ltd (8.4%) and Moshbacher Operating Ltd (0.5%). The associated Maritimes and Northeast Pipeline Project is owned by Duke Energy (75%), ExxonMobil (12.5%) and Nova Scotia Power (12.5%). While ExxonMobil is thus a gas producer with an interest in a gas pipeline, it should be noted that no producer with an interest in the Sable project has an interest in its associated transportation infrastructure.

of suppliers, although few residential customers have elected to switch from their traditional local distribution company to a competitive gas marketer outside of Alberta and Ontario. In Ontario, over 70 percent of all gas used is bought from competitive marketers or from producers directly, rather than from local distribution companies (LDCs), and about half of residential customers buy gas from marketers.[35]

For smaller customers who do not choose to purchase gas from a retail marketer, provincial authorities and regulatory boards ensure that LDCs pass the natural gas commodity cost directly to consumers without marking it up. They also ensure that the LDCs buy gas prudently and manage costs on behalf of consumers. Gas utilities in almost every province hedge a portion of their gas supplies with the approval of provincial regulators.

Ontario is the largest provincial market for natural gas in Canada and is highly diversified in its gas consumption, with 31 percent of gas demand occurring in the residential sector and 20 percent in the commercial sector in 2001.[36] Because of the importance of small customers in this market, the provincial government has been particularly eager to promote retail choice by such customers. The Ontario Energy Board (OEB) promulgated a Gas Distribution Access Rule in December 2002, which requires that the retail supply and distribution functions of LDCs be unbundled and that gas distributors be required to treat all competing gas vendors on non-discriminatory terms. This should make it more difficult for LDCs to discriminate in favour of the supplies for which they have contracted themselves. In addition, the Ontario government passed the Reliable Energy and Consumer Protection Act in June 2002 which gives the OEB greater power to protect electricity and gas consumers against unfair market practices by retailers.[37] Steps like these should help to encourage supplier choice by smaller customers.

Gas market competition has been enhanced, in recent years, by the emergence of competing gas pipelines. Traditionally, gas pipeline transmission networks have been viewed as natural monopolies in which effective competition is precluded by economies of network linkage and scale. But gas volumes in the Canadian transmission network have been sufficient to support a move away from the natural monopoly model for transportation. With the market entry of the Alliance and Vector pipelines, along with several shorter pipelines that bypass the main gas transmission grid, gas transportation in Canada has come to be characterised by limited pipeline competition.

There is little vertical integration between Canadian gas and electricity markets. There are several competing power generators in most provincial electricity markets, and each generator has a choice among many competing gas producers. No gas producers generate electricity for sale, so there is no incentive for any producer to provide gas on a preferential basis to any generator. By the same token, there is generally no reason why any electricity generator would try to obtain gas from any but the least-cost source of supply. While two gas transmission companies generate power (TransCanada Pipeline and Westcoast Energy), requirements for open access to pipelines effectively preclude them from giving preference to their power plants in gas transportation.

PRICE TRENDS

Following deregulation of wellhead natural gas prices and provision for mandatory open access to the gas transmission grid in 1985, delivered gas prices in Canada declined markedly. For industrial customers, the real price in 2000 US$ was halved from US$150 per tonne of oil equivalent in 1985 to US$73 per toe in 1998. The real price for electric power producers declined by one-third from US$100 per toe in 1985 to US$66 per toe in 1992. Gas prices for households declined by a quarter in real terms from US$233 per toe in 1985 to US$176 per toe in 1998.[38]

---

[35] Canadian Gas Association (2002). National Energy Board (2002), page 27.

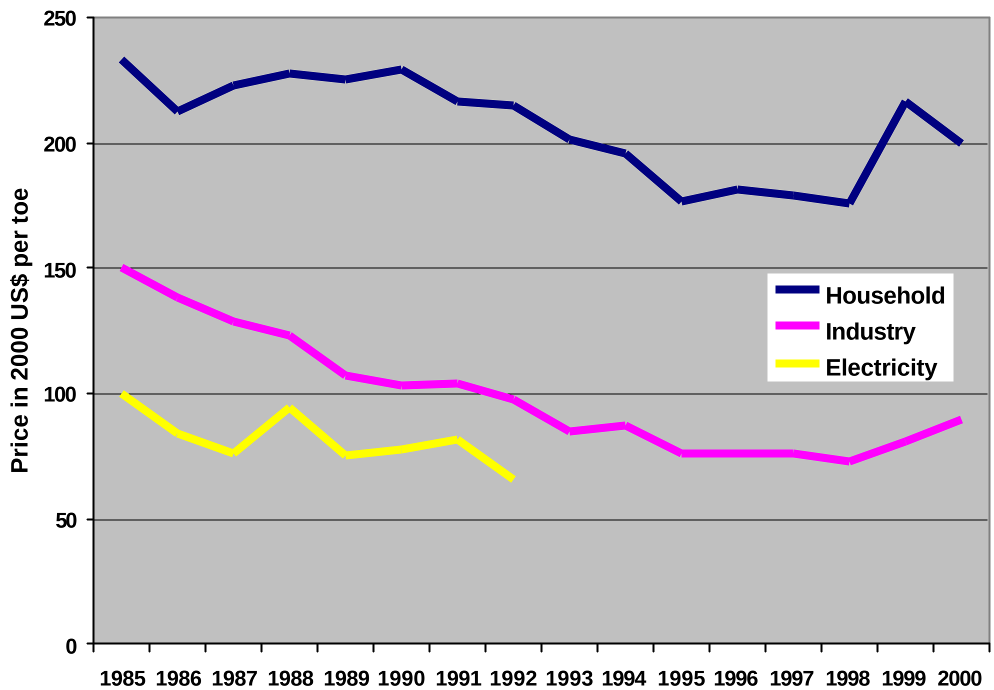
[36] Natural Resources Canada (2001), page 6.

[37] Ontario Ministry of Energy (2003).

[38] International Energy Agency (1997) pages II.19-21, IEA (2002a) pages III.30-32. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

The sharp decline in prices that followed wellhead price deregulation is largely due to the fact that prices had been regulated from 1975 through 1985 at what became unsustainably high levels. Drilling incentives caused large amounts of gas to be discovered, and long-term "take or pay" contracts with gas pipelines at high prices caused large amounts of gas to be produced. But high end-use prices, which bundled together regulated production and transportation charges, discouraged gas consumption. Hence, a large "bubble" of excess gas supply developed. Gas pipelines could not resell all the gas for which they had contracted and were threatened with bankruptcy unless the contract terms could be renegotiated. With wellhead price deregulation and unbundling of wellhead prices from transportation charges, along with the introduction of direct sales between buyers and producers, prices soon fell to where supply and demand were in balance.

Figure 27 Natural Gas Prices in Canada, 1985-2000



Source: International Energy Agency, US Department of Commerce.

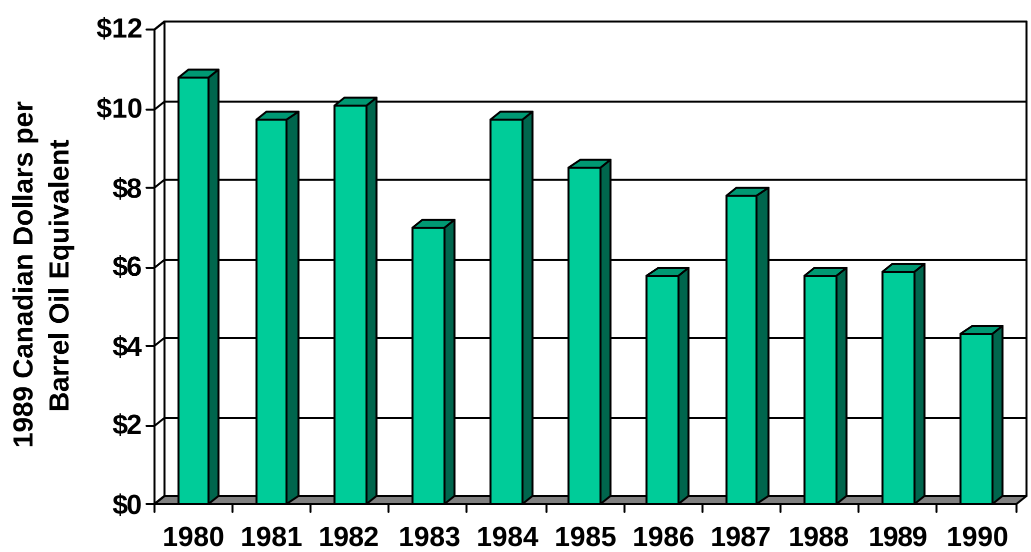
However, the sustained trend of gas price declines that continued through the mid 1990s can be attributed in large part to improved efficiency in gas production and transportation. The transportation component of efficiency improvement was connected with the rebalancing of supply and demand, as greater demand stimulated by lower prices increased pipeline throughputs. With greater throughput on existing infrastructure, the cost per unit of gas transported was reduced. But the production component of efficiency improvement was due to the increased competition that market reforms brought about. Greater competition, combined with new technologies, helped to halve finding and development costs in constant 1989 Canadian prices per barrel of oil equivalent from more than Can$8 in 1985 to just over Can$4 in 1990.[39]

Natural Resources Canada (NRCan) notes that the volume of Canadian gas exports to the United States has quadrupled since 1986, "primarily due to the deregulation of prices." It also states that "expansion of market share in the U.S. is the result of increased wellhead productive capacity, the construction of new pipelines, and competitive funding and development costs for natural gas in Canada." The clear inference is that competitive gas markets in the United States and

[39] Glenn Booth, Chief Economist, National Energy Board (2003).

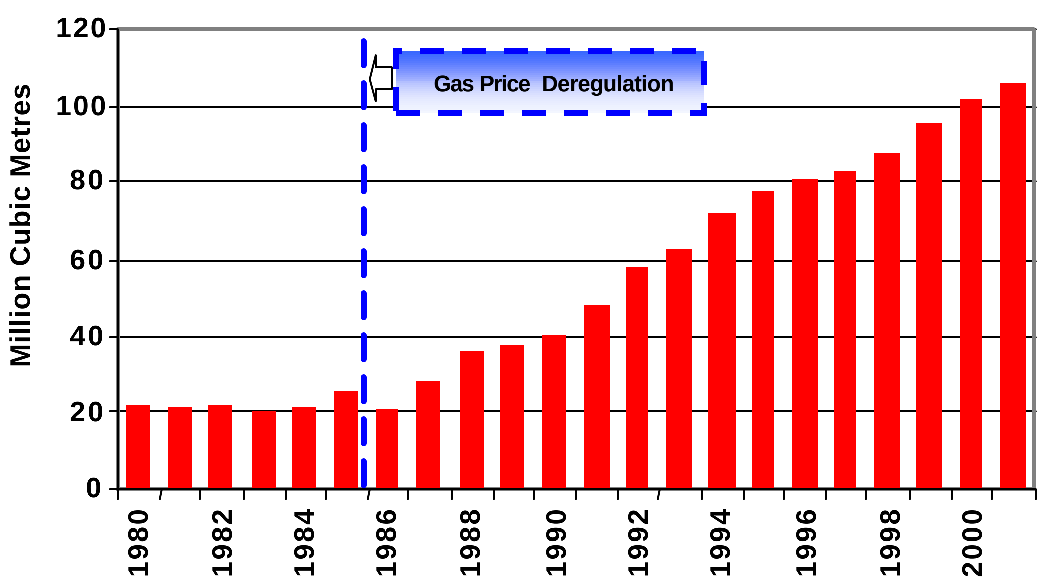
Canada provide price signals that show where gas is needed and provide the opportunity to earn profits by expanding production facilities and transportation infrastructure to deliver the gas where needed. Real revenues from gas exports, in 2002 Canadian dollars, have increased roughly five-fold since market reforms were implemented, from Can$3.8 billion in 1986 to Can$4.2 billion in 1990 to Can$7.5 billion in 1994 to Can$9.8 billion in 1998 to Can$18.8 billion in 2002.[40]

Figure 28 Natural Gas Finding Costs in Canada, 1980-1990



Source: National Energy Board

Figure 29 Canadian Gas Exports Before and After Wellhead Price Deregulation



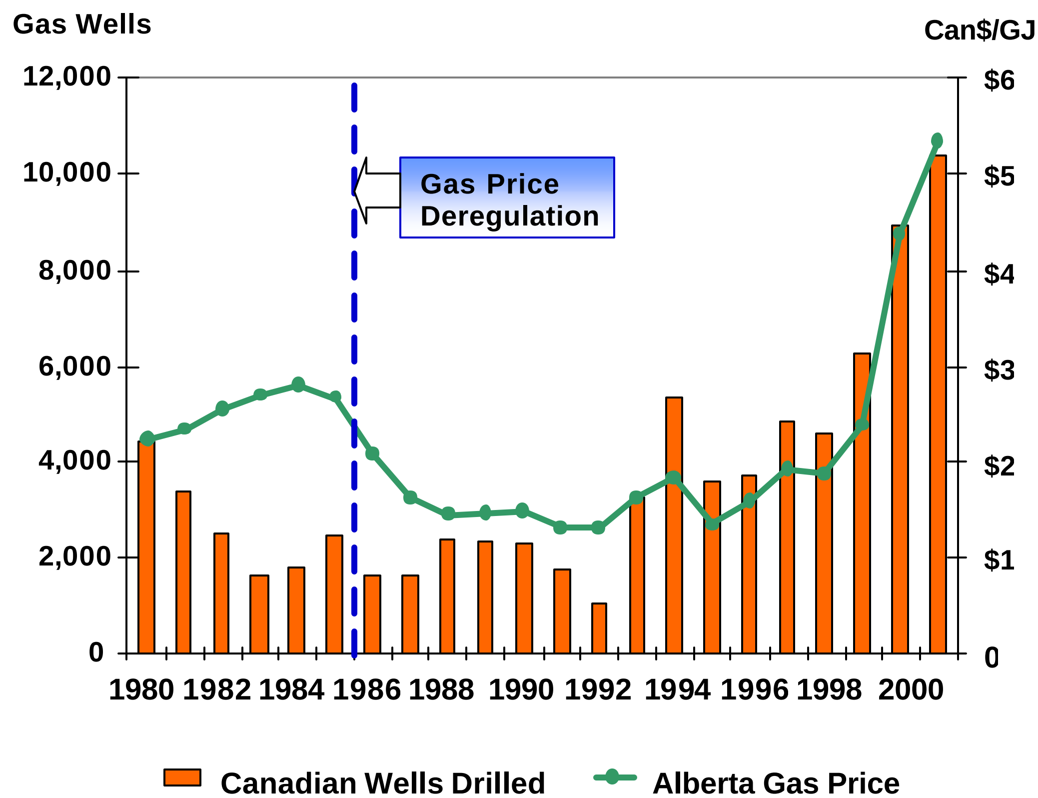
Source: National Energy Board

[40] Natural Resources Canada (2000), pages 60-61. Statistics Canada (2003a) and (2003b). Real export revenues in 2001 were even higher (Can$26.2 billion) due to temporary price spikes associated with a tight gas market, described below.

Natural gas price spikes during the winter of 2000-2001 brought average spot prices at the AECO-C hub in Alberta to nearly Can$14 per gigajoule in January 2001, more than four times the prices during the winters before and after. The National Energy Board attributes these price spikes to unusually low levels of natural gas in storage and record cold weather, as well as feedback effects from natural gas price spikes in the United States. Very low rainfall reduced the availability of hydropower in the western US, requiring additional gas-fired power generation. With cold weather and low gas storage levels in the US as well as Canada, and with constraints in California's gas transmission network that made it difficult to deliver gas where it was needed, increased gas requirements "led to sharply increased gas prices in California which were transmitted back to British Columbia and resulted in prices at the border in the order of $20/GJ by early 2001."[41]

However, Canadian gas prices soon subsided due to a combination of demand-side and supply-side factors. Demand was reduced through energy conservation by residential and commercial consumers, fuel-switching and reduced plant operations by industrial gas users, milder weather and a weakening economy. Supply was increased as record levels of gas well drilling led to a modest increase in gas production and as lower demand and higher production allowed more gas to be delivered to storage. Consequently, Canadian gas prices had declined to below US$2 per MBtu by the end of the summer of 2001 (about 80 percent of the level then at the US Henry Hub).

Figure 30 Canadian Gas Wells Drilled Compared with Average Alberta Gas Prices



Source: National Energy Board

The response of Canada's gas market to recent price spikes can be seen as an example of the benefits of market reforms for security of supply. The NEB has noted that over the 18-month period through October 2002, "all consumers faced higher prices for natural gas" but "gas

[41] National Energy Board (2002), pages 1-2.

continued to flow and the needs of Canadians were fairly met."[42] A temporary imbalance between supply and demand resulted in sharply higher gas prices. The higher gas prices provided clear incentives to boost gas production and limit gas use, which in turn caused prices to moderate.

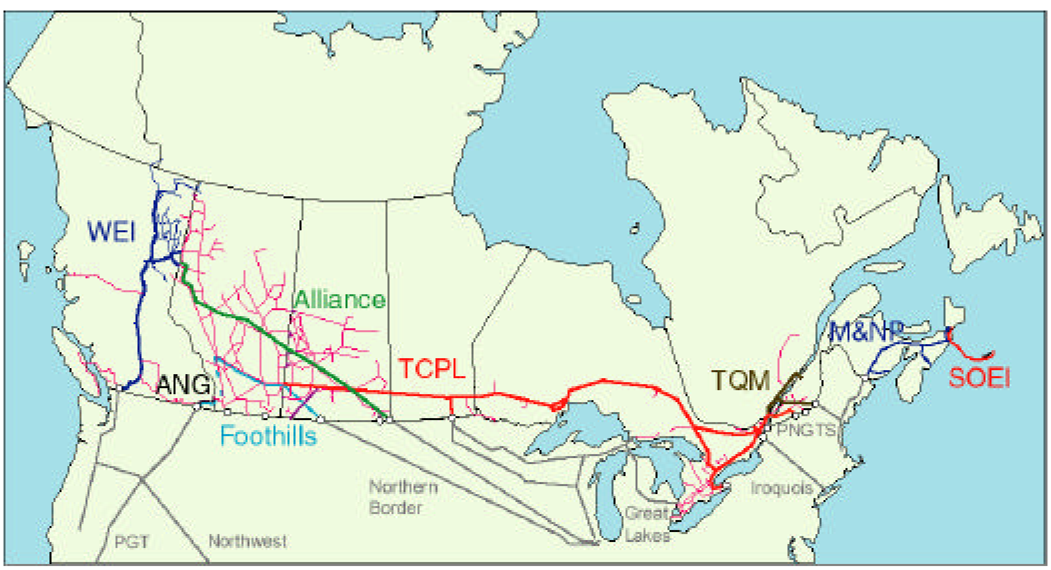
GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Almost 80,000 km of transmission pipelines carry natural gas from processing plants to consuming regions and export points across Canada. The largest component of the transmission grid is the TransCanada Pipeline which has 14,900 km of pipeline moving 2.7 Tcf (76 Bcm) of gas annually. The main pipeline network is best developed in the gas-producing province of Alberta but extends west to British Columbia and east to Quebec. New Brunswick and Newfoundland are separately served by pipelines from recent Scotian Shelf gas developments in the Atlantic. Only Prince Edward Island and northern jurisdictions such as Yukon and Northwest Territories do not have access to the grid. Extensive pipeline linkages with the United States allow gas to be exported from the Canadian West. These linkages also allow Canadian gas to be reimported from the US Midwest after travelling along part of the US pipeline network.

As demand for natural gas increases, it is anticipated that new supplies will be developed in the Northwest Territories, Yukon and other frontier areas. Large-volume production from these areas will not be feasible until new pipelines are constructed to southern markets. A proposed new pipeline, the Mackenzie Valley Project, would bring gas from frontier areas to the TransCanada or Alliance pipeline for delivery to major markets. However, the need for new gas transmission infrastructure will mainly develop over the long term, since load factors on existing export pipelines were only around 85 percent in 2002 and were expected to rise only to about 93 percent by 2010.[43]

Figure 31 Major Gas Pipelines in Canada



Source: National Energy Board

[42] *Ibid.*, page 44.

[43] Natural Resources Canada (2002), page 53.

Canada has well-developed gas distribution networks in almost all of its major urban areas. The main exception is towns in the Atlantic provinces of New Brunswick and Nova Scotia, where gas has only recently become available and construction of dstribution grids is at an early stage. There are no plans to extend gas distribution systems to the very sparsely populated northern regions. However, gas distribution grids have been expanding in rural Manitoba and Saskatchewan.

INFRASTRUCTURE INVESTMENT INCENTIVES

The gas industry in Canada is regulated at both federal and provincial levels by independent agencies. At the federal level, the National Energy Board (NEB) regulates the routes and tariffs of inter-provincial and international pipelines, as well as natural gas exports. Provincial bodies, which regulate the routes and tariffs of distribution pipelines within their respective jurisdictions, include the Alberta Energy and Utilities Board, British Columbia Utilities Commission, Manitoba Public Utilities Board, Nova Scotia Utility and Review Board, Ontario Energy Board, Régie de l'Energie du Québec, and Saskatchewan Rate Review Panel. Combined federal-provincial boards, including the Canada-Newfoundland Offshore Petroleum Board and the Canada-Nova Scotia Offshore Petroleum Board, regulate offshore oil and natural gas activities. Municipalities regulate gas delivery and rights-of-way for distribution pipelines within their borders.

Investment incentives for enhancement of gas transmission and distribution grids in Canada appear to be adequate. Both federal and provincial governments generally allow a return on approved grid extensions that is based on the weighted cost of borrowing capital. In 1995, the NEB adopted an automatic adjustment mechanism for determining the appropriate rate of return on equity for all major natural gas pipelines. The NEB holds consultations and hearings prior to approving new pipelines, and environmental assessments are always part of the review process. However, there is no official planning process at either federal or provincial level for expansion of gas transmission and distribution grids. The initiative for construction of new pipelines generally comes from private companies, based on their assessment of market needs and opportunities.

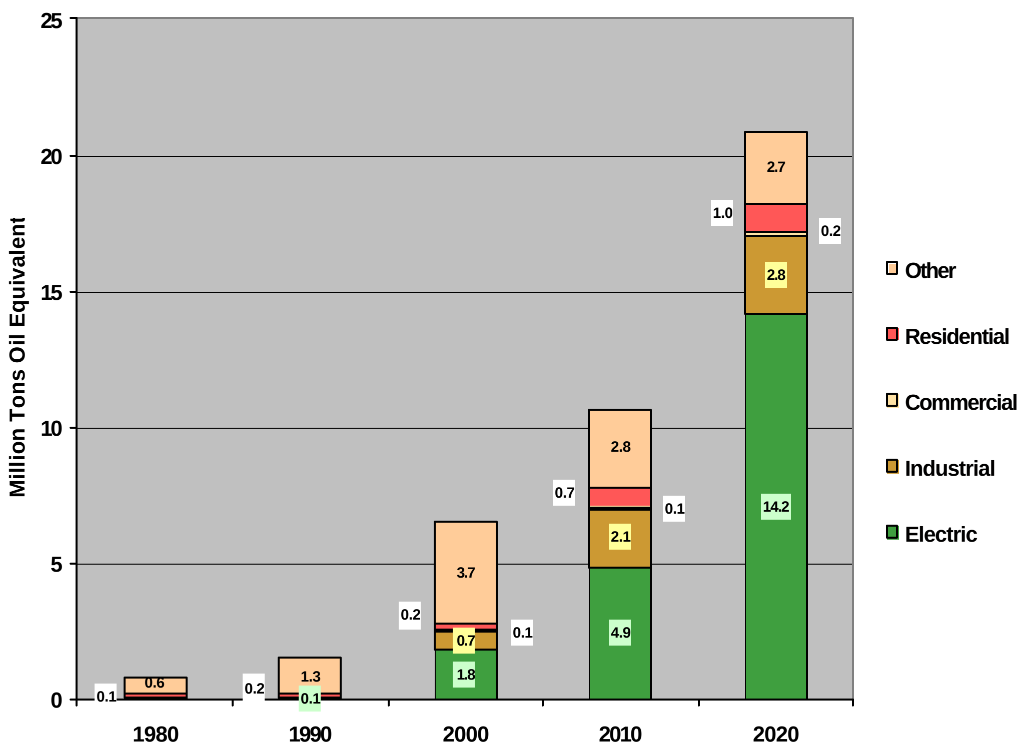
CHILE

GAS MARKET SETTING[44]

Chile produces a small amount of natural gas but relies on imports for most of its needs.

- Domestic gas production, including natural gas as well as town gas, is projected to decline from 2.0 Mtoe in 2000 to 0.7 Mtoe in 2020, so that the share of gas demand met by domestic production declines from 31 percent to 3 percent.
- Imports of gas, which currently come from Argentina but may also come from Bolivia or Peru in the future, are projected to more than quadruple from 4.5 Mtoe in 2000 to 20.2 Mtoe in 2020.
- Primary supply of gas to the domestic economy is projected to more than triple from 6.5 Mtoe in 2000 to 20.9 Mtoe in 2020, with rapid growth averaging 5.0 percent per annum in the decade from 2000 to 2010 and 7.0 percent per annum from 2010 to 2020.

Figure 32 Evolution of Natural Gas Use in Chile, 1980-2020



Almost all of Chile's natural gas use is devoted to energy transformation and industry. More than four-fifths of the economy's gas is used in energy transformation. Of this portion, about a third goes to electricity generation and two thirds to gas and methanol production and oil refining, but the relative importance of electricity generation is expected to grow rapidly. Remaining gas use takes place mostly in industry, with some gas also used in the residential and commercial sectors.

[44] Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Use of gas for electric power generation is projected to grow nearly eight-fold from 1.8 Mtoe in 2000 to 14.2 Mtoe in 2020, so that the power sector's share of overall gas demand far more than doubles from 28 percent to 68 percent.
- Industrial use of gas is also expected to grow substantially, quadrupling from a small base of 0.7 Mtoe in 2000 to 2.8 Mtoe in 2020, so that its market share grows from 10 percent to 14 percent.
- "Other" gas use, mainly for gas and methanol production and oil refining, is expected to decline in both absolute and relative terms, so that its share of the gas market falls by more than a factor of four from 57 percent in 2000 to only 13 percent in 2020.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

There are several sources of gas production for the Chilean gas market. Most of the economy's natural gas comes from Argentina, where nine different companies are operating in six competing gas production consortia. Some natural gas is also extracted by the state-owned Empresa Nacional del Petróleo (National Petroleum Company - ENAP) in the Magallanes Region of southern Chile. There are several producers of town gas and liquefied petroleum gas (LPG) as well. Chile's constitution gives the state "absolute, exclusive, inalienable" rights over fossil fuel reserves, which can be exploited only by the state or state-owned companies or through operational contracts for the services of private companies. But because there is freedom to invest in natural gas pipelines and to import gas from elsewhere, ENAP's monopoly on domestic natural gas production accounts for just about a quarter of gas demand, which is concentrated almost entirely in methanol production and has little impact on the competitiveness of the overall gas market.[45]

PRINCIPAL PLAYERS IN CHILE'S GAS MARKET

External Producers from which Chile Imports Gas

Argentina: Pluspetrol-Astra, Propietarios de Sierra Chata, Tecpetrol-Mobil-CGC, Total-Pan American-Wintershall, YPF, YPF-Total-Pan American-Wintershall

Domestic Gas Producers in Chile

Natural gas: Empresa Nacional del Petróleo (ENAP)
Town gas: Gasco, Abastible

Owners and Operators of Gas Transmission Pipelines in Chile

Electrogas, ENAP, GasAndes, Gasatacama, Gas Pacífico, INNERGY Transportes, Norandino, Red SGN Transporte, Taltal

Owners and Operators of Gas Distribution Pipelines in Chile

Enagas, Energas, GasAntofagasta, Gasco, Gasvalpo, Gas Sur, Metrogas, Progas

Other Gas Retailers in Chile

LPG: Abastible, Agrogas, Codigas, Distrinor, Ecogas, Gasmar, Intergas, Lipigas, Uligas

Sources: CNE, SEC, TGN

45 Comisión Nacional de Energía (2002a), Annex A1-1. Gas use in the economy in 2001 included 67,663 Tcal of natural gas, 12,051 Tcal of LPG and 1,457 Tcal of town gas, totalling 81,171 Tcal. Natural gas production by ENAP in 2000 was 2.002 Mtoe or 20,020 Tcal. If production in 2001 was similar, this would amount to 25 percent of gas use.

Several companies are involved in the transmission of natural gas from Argentina to local markets in Chile. Imports to Chile come through one of two pipeline systems in Argentina. In the north and central regions, they are routed mainly through Transportadora de Gas del Norte (TGN), while in the south, imports come mainly through Transportadora de Gas del Sur (TGS). Cross-border and domestic pipelines are owned and operated by nine different companies. Transmission companies sell gas directly to large consumers, such as power generators, oil refineries, a methanol producer, and large industrial consumers, as well as to local distribution companies.[46]

There are eight local gas distribution companies, each of which has a territorial franchise to supply natural gas in a different area. Distribution concessions oblige companies to provide service in their concession areas. Some distribution companies sell town gas as well as natural gas through their grids, and some sell bottled LPG too. Another nine competing retail suppliers also sell LPG in local gas markets, both in bulk to industrial customers and in bottles to smaller customers.[47]

UNBUNDLING AND THIRD PARTY ACCESS

Gas production and transportation are generally unbundled in the Chilean gas market. Most natural gas supply comes from various producers in Argentina, which are not associated with the pipeline companies in Argentina and Chile that move the gas to market. Production and transport of gas remain bundled only with respect to ENAP, which produces, transports and distributes natural gas to large consumers in southern Chile, and with respect to town gas, which is produced and supplied by the same local distribution companies in several metropolitan areas. The share of town gas in the Chilean gas market is small, and the share of ENAP gas is rapidly shrinking.

On the other hand, gas distribution and retail supply of gas in Chile generally remain bundled. The eight local distribution companies are the sole retail suppliers of natural gas, and of town gas where it is still produced and sold, in their respective franchise areas. The nine independent retailers of LPG distribute their product through their own fleets of trucks.

Gas transport companies are obliged by law to grant third-party access on non-discriminatory terms. Hence, electricity generators and large industrial firms, which can hook up with the high-pressure pipeline grid, are able to contract for gas directly with various gas producers. However, distribution companies are not obliged to grant third-party access and retain local distribution franchises, so smaller consumers cannot contract with competing gas producers.

MARKET MODEL AND COMPETITION

The gas market in Chile resembles a mix between the wholesale competition and customer choice models. Power producers and industrial firms can choose from among several competing gas producers, most of them in Argentina, because of third party access to the transmission grid in both Argentina and Chile. But smaller residential and commercial customers are generally obliged to buy natural gas or town gas from their local distribution company. While the distribution companies benefit from wholesale competition among the various gas producers, they are not obliged to pass on all of the resulting cost savings to smaller retail customers. On the other hand, the distribution companies do face real competition from LPG, which constituted 45 percent of all gas sales in Chile in 2001 and 70 percent of gas sales to residential and commercial customers.[48]

Regulation has focused on ensuring non-discriminatory access by competing suppliers to the gas transmission grid. Since ownership of high-pressure gas pipelines is generally unbundled from gas production (except for ENAP's share), there is little incentive for pipelines to discriminate in favour of one producer or another. Prices are set in the gas market without government intervention, on the assumption that competition will keep prices reasonable. Market power and

[46] Comisión Nacional de Energía (2002a) and (2003). TGN (2003). TGS (2003).

[47] Comisión Nacional de Energía (2003).

[48] Comisión Nacional de Energía (2002a), Annex A1-1. Final gas consumption in 2001, which totalled 26,576 teracalories, included 12,039 Tcal of LPG, 1,391 Tcal of town gas and 12,445 Tcal of natural gas. Residential and commercial gas consumption, totalling 15,408 Tcal, included 10,800 Tcal of LPG, 419 Tcal of town gas and 4,189 Tcal of natural gas.

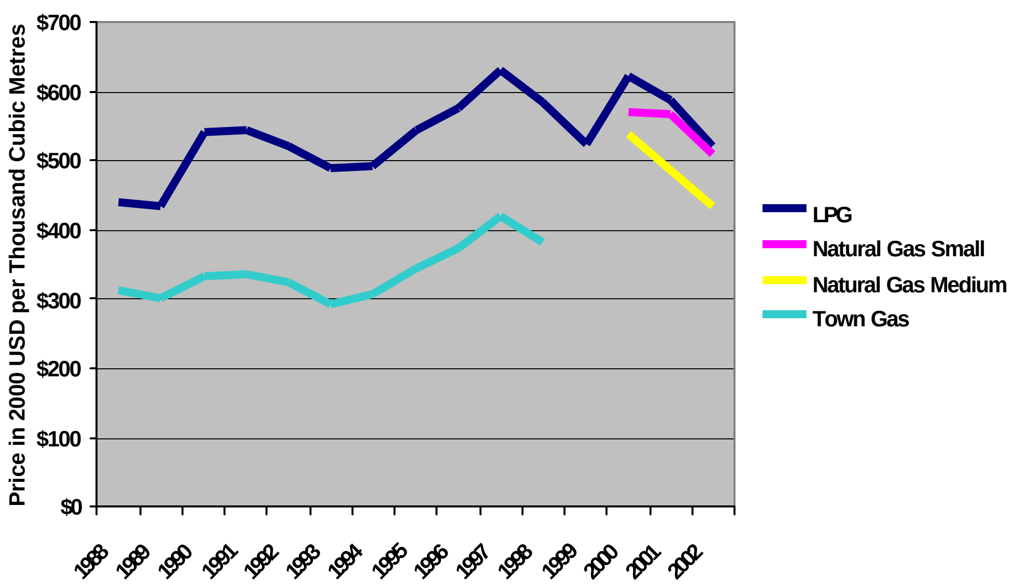
anti-competitive behaviour are monitored by central and regional "preventive commissions", the Resolution Commission, the National Economic Prosecutor (Fiscalía), and municipal governments.[49]

There is some degree of integration between gas and electricity markets in Chile due to cross-ownership of gas transportation pipelines by power generators. About a quarter of Chile's electricity is generated from natural gas.[50] Electricity generating companies hold majority shares in three major gas pipelines (Endesa in GasAtacama, Endesa and Colbun in Electrogas, and Tractebel and Edelnor in Norandino), and minority shares in another pipeline (AESGener in GasAndes).[51] Thus, there could be incentives for pipelines to discriminate in favour of the power generators that have financial interests in them. However, anti-competitive behaviour is subject to regulatory penalties. Thus, the extent of effective integration depends on the ability of regulatory authorities to monitor and punish anti-competitive behaviour on a timely basis. Since power is generated by several competing producers, each of which has a wide choice among competing gas suppliers, it should be difficult for a gas transporter to raise prices significantly above competitive levels, even for those electricity generators with which it is not affiliated. If competitive market forces are joined by regulatory enforcement, the effective integration of gas and electricity markets may be quite limited despite the high degree of cross-ownership between them.

PRICE TRENDS

Wholesale natural gas prices largely depend on wellhead prices in Argentina and Chile and are generally set through long-term contracts. The price of gas for methanol production, which comes mainly from the Magallanes and Austral basins, is substantially lower than the price of gas for other uses, which comes mainly from the Noroeste and Neuquén basins. This reflects, among other factors, shorter transport distances between production and consumption points. While the prices for methanol production generally ranged from US$25 to US$50 per thousand cubic metres between 1999 and 2001, the prices for other uses were roughly twice as high, ranging from US$75 to US$90 per thousand cubic metres.

Figure 33 Gas Prices for Residential Consumers in Santiago, Chile, 1988-2002



Sources: Derived from Comisión Nacional de Energía (2003), Banco Central (2003). "Small" natural gas consumers are those using 19.3 cubic metres per month. "Medium" natural gas consumers are those using 58 cubic metres per month.

---

49 Comisión Nacional de Energía (2003).

50 APEC Energy Working Group (2002), pages 58-9.

51 AESGener (2003). Colbun (2003). Edelnor (2003). Endesa (2003).

Since natural gas was introduced to Santiago in 1997, price trends for LPG and natural gas have tracked each other closely, as shown in the figure above. Thus, it is fair to suppose that the moderation in LPG prices has been due in part to competition from natural gas. Town gas and LPG prices have also moved in similar directions over time, with town gas selling at a 30 to 40 percent discount to LPG on a volumetric basis owing to its lower energy content per unit volume.[52]

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Chile has some 3,017 km of gas transmission pipelines that connect with some 1,638 km of Argentina's gas transmission grid at six points along the border. The GasAtacama, Norandino and GasAndes cross-border pipelines take gas from the Noreste Basin. The Gas Pacífico pipeline gets gas from Loma La Lata, in the Neuquén Basin. Two pipelines in the south import gas from the Austral Basin. Several projects to expand the gas transmission grid are planned or underway.

Distribution networks are being established in all of Chile's major consumption centres. Networks that previously distributed town gas produced from naphtha have been converting to natural gas. Following the introduction of natural gas in central Chile in 1997, the number of gas consumers doubled within two years and had increased nearly eight-fold by mid-2002.[53]

INFRASTRUCTURE INVESTMENT INCENTIVES

Gas transmission and distribution companies must have concessions to operate. The former are obliged to grant third-party access and the latter to provide service in their concession zones. Gas transmission, distribution and retail supply businesses are privately owned and do not receive financial incentives from the government. On the other hand, transporters and suppliers of gas are free to charge what they wish for their services. Market conditions and environmental regulation, especially in the power sector, have driven the expansion of gas infrastructure. International treaties regarding cross-border pipelines have established a clear framework for investments.

52 Real prices calculated by converting prices in current Chilean pesos to current US$ at prevailing exchange rates in each year and then dividing by implicit GDP deflators from US Department of Commerce to get prices in 2000 US$. Prices in current Chilean pesos are from Comisión Nacional de Energía (2003), exchange rates from Banco Central (2003).

53 Comisión Nacional de Energía (2002b) and (2003).

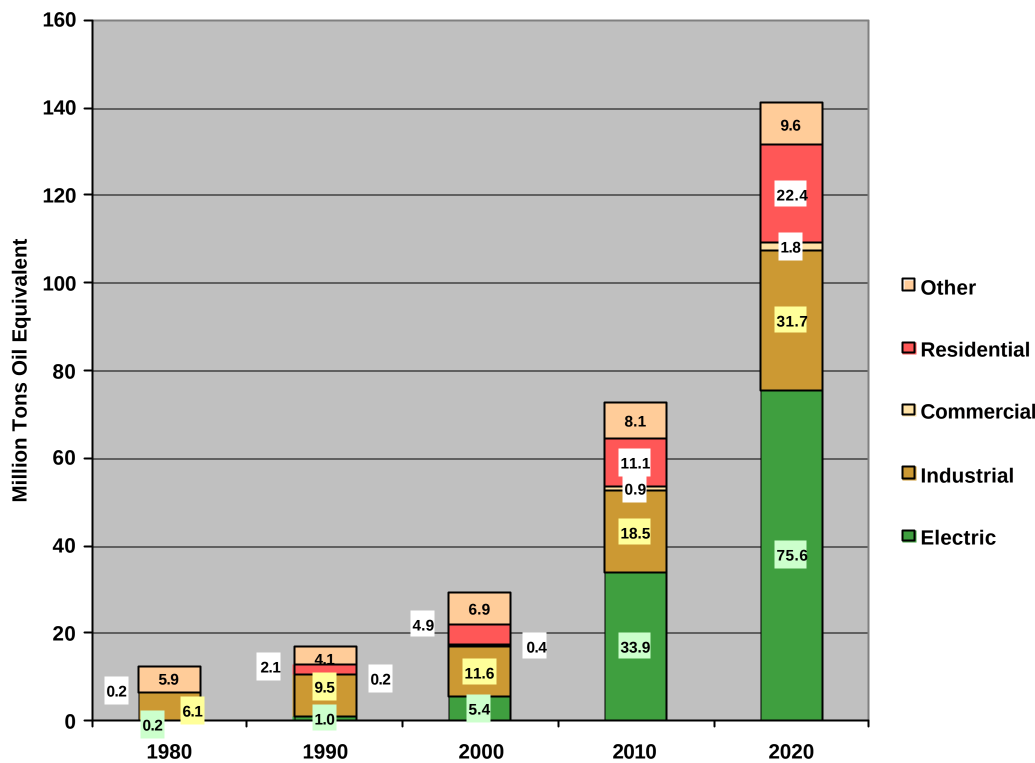
CHINA

GAS MARKET SETTING[54]

China both produces and consumes a substantial amount of natural gas, with production roughly sufficient to meet domestic demand but not expected to remain so as expansion of production capacity is outpaced by growth in gas requirements.

- Gas production (including some town gas produced mainly from coal) is projected to grow nearly two-and-a-half-fold from 29.1 Mtoe in 2000 to 71.1 Mtoe in 2020, at which time it would satisfy only about half of all gas needs.
- Net imports of gas, which were negligible in 2000, are projected to amount to some 70 Mtoe by 2020 to meet growing needs.
- Primary supply of gas to the domestic economy is projected to more than triple from about 33 Mtoe in 2000 to 103 Mtoe in 2020, with rapid growth averaging 6.6 percent yearly from 2000 to 2010 and 5.2 percent yearly from 2010 to 2020.

Figure 34 Evolution of Natural Gas Use in China, 1980-2020



54 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

China's natural gas use is fairly diversified. Most of the economy's gas demand emanates from the electric power and industrial sectors, but substantial gas use occurs in the commercial and residential sectors as well.

- Very rapid growth is projected to continue in the use of gas for electric power generation, with a 14-fold increase projected from 5.4 Mtoe in 2000 to 75.6 Mtoe in 2020. Correspondingly, electricity's share of total gas use in the economy is expected to triple from 18 percent to 54 percent.
- Industrial gas use is also projected to grow substantially, nearly tripling from 11.6 Mtoe in 2000 to 31.7 Mtoe in 2020. But the industrial share of overall gas demand is projected to decline by nearly half, from 40 percent to 22 percent, due to the much faster growth anticipated in gas use for power production.
- Commercial and residential gas use are both expected to quadruple, the former from a very small base of 0.4 Mtoe in 2000 to 1.8 Mtoe in 2020, the latter from 4.9 Mtoe in 2000 to 22.4 Mtoe in 2020. Their shares in overall gas use, however, should be little changed; the commercial share is projected to remain slightly above 1 percent, the residential share to decline from 17 percent to 16 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

China's substantial indigenous gas production is mostly divided between three companies. One company is state-owned and has a monopoly on offshore gas production. The other two have a majority state ownership interest and dominate onshore gas production.

- The largest gas company is PetroChina, which is the gas and oil exploration and production arm of the China National Petroleum Corporation (CNPC). PetroChina has the fourth-largest gas reserves of any company in the world and produced 66 percent of China's gas in 2000. PetroChina was listed as a public corporation on the Hong Kong and New York stock exchanges in April 2000, with the China National Petroleum Corporation holding a controlling stake.[55]
- The second-largest gas company is the China Petroleum and Chemical Corporation (Sinopec), which produced 14 percent of the economy's gas in 2000. With a large portion of its shares listed in Hong Kong, New York, London and Shanghai, Sinopec is owned 55 percent by the state, 22 percent by domestic banks and asset management companies, 19 percent by foreign investors, and 3 percent by domestic investors.[56]
- The third main gas company is the state-owned China National Offshore Oil Corporation (CNOOC), which produced 14 percent of China's gas in 2000.[57]
- The remaining 6 percent of gas production is controlled by small local companies.[58]

Transmission of gas in China is handled by the three principal gas producers. Most of the onshore pipeline network is owned and operated by PetroChina's parent, CNPC. In some areas, however, including Sichuan province in the southwest and Henan province in the north, the pipeline network is owned and operated by Sinopec. All offshore pipelines, as well as all LNG terminals and some onshore pipelines linking LNG terminals and offshore pipelines to the city of

[55] CNPC (2003) and PetroChina (2003).

[56] Sinopec (2003).

[57] CNOOC (2003a) and (2003b).

[58] PETEC Software and Services (2003).

Shanghai, are owned and operated by CNOOC. In essence, each of the three main gas companies operates as an integrated production and transmission company in a distinct sphere of operation. While CNPC controls production and transmission in most of China, Sinopec does so in certain provinces and CNOOC does so for all gas that comes from offshore. CNOOC will also run the LNG facilities that will start bringing gas to Guangdong province from Australia in 2005 and will start bringing gas to Fujian province from Indonesia in 2007.[59]

Distribution of gas to small residential and commercial users is performed by several dozen companies, each with its own franchised distribution area, to which gas is delivered by one of the three major integrated production and transportation companies. In addition, CNOOC and Sinopec deliver substantial amounts of gas to their own petrochemical industrial enterprises.

PRINCIPAL PLAYERS IN CHINA'S GAS MARKET

Gas Producers in China

PetroChina (China National Petroleum Corporation – CNPC) – onshore north
China Petroleum and Chemical Corporation (Sinopec) – onshore south
China National Offshore Oil Corporation (CNOOC) – offshore

Owners and Operators of Gas Pipelines in China

China National Petroleum Corporation – CNPC
China Petroleum and Chemical Corporation (Sinopec)
China National Offshore Oil Corporation (CNOOC)

Owner and Operator of LNG Terminals in China

China National Offshore Oil Corporation (CNOOC)

Owners and Operators of Gas Distribution Pipelines in China

Beijing Gas Fuel Company
Shanghai Natural Gas Development Company
Several dozen other municipal gas utilities

Sources: CNPC, CNOOC, Sinopec, IEA

UNBUNDLING AND THIRD PARTY ACCESS

The production and transmission of gas in China are tightly bundled. While there are three separate major gas companies, each both produces and transports its own gas. On the other hand, small producers, without their own pipelines, account for a small and growing share of the market. Moreover, distribution is clearly unbundled from production and transmission; each major city and town has its own local distribution monopoly.

There is currently no legal requirement for third-party access to the gas transmission grid in China. PetroChina and Sinopec use their pipelines mainly for their own production, and CNOOC uses its pipelines entirely for its own production. Small gas producers can obtain access to pipelines only on a negotiated basis, essentially on terms that the three major producer-transporters dictate.

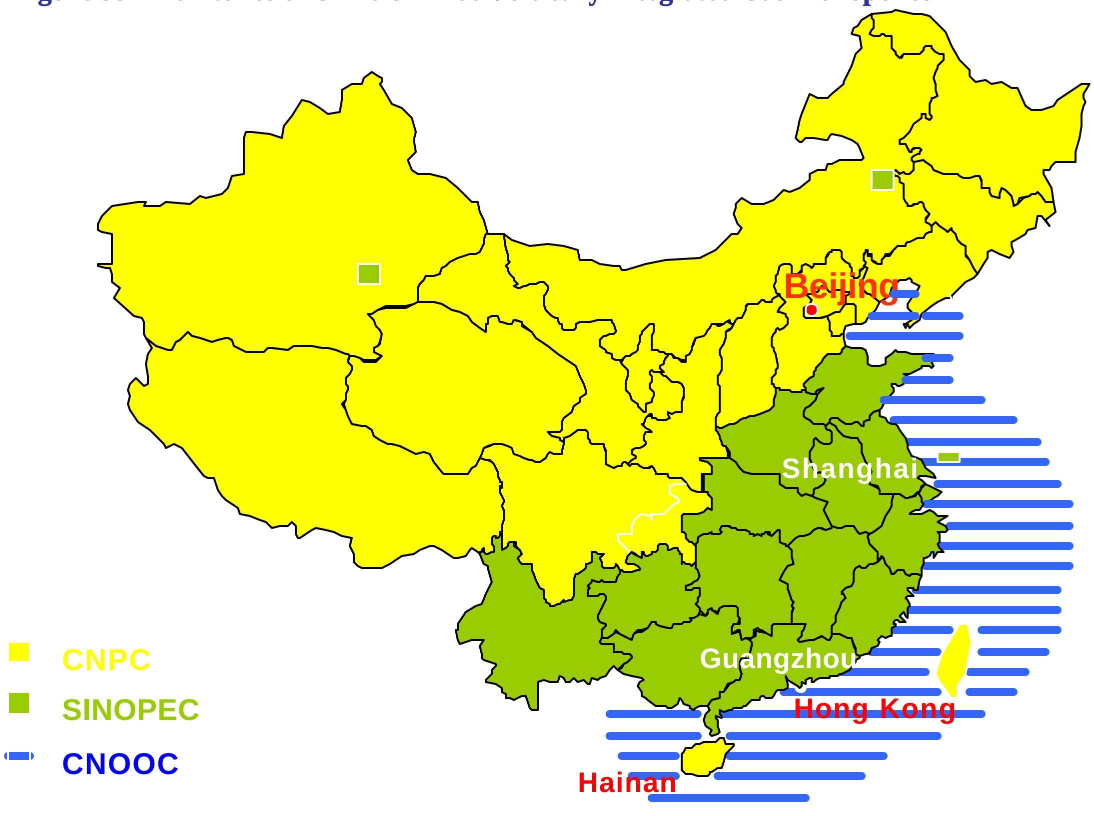
Looking forward, gas transportation and production may someday be unbundled. The government anticipates that the operation of powerplants and transmission grids will be unbundled in the power sector, with competitive wholesale bidding for generation by independent power producers (IPPs). Perhaps a similar principle may ultimately be applied to gas, particularly if access to the high-pressure pipeline grid is sought by a growing number of competing producers.

[59] CNPC (2003). Sinopec (2003). CNOOC (2003a) and (2003b).

MARKET MODEL AND COMPETITION

The gas market in China would seem to fit most closely the vertically integrated monopoly model. With respect to 93 percent of the economy's gas production, gas is transported by the company that produces it. With respect to the other 7 percent of gas production, transportation can be obtained only on terms highly favourable to the integrated production-transport company in the area where competing production is located. While there are many different local distribution monopolies, each can obtain gas from only one of the production-transport companies.

Figure 35 Territories of China's Three Vertically-Integrated Gas Monopolies



Source: International Energy Agency

As China's gas demand grows and an increasing share of demand is met by imports from a variety of sources, there is some prospect that real wholesale competition could develop. Even if CNOOC retains its monopoly on LNG terminals, it may well import gas from a growing number of foreign suppliers. These might include any of the sources that already supply LNG to Northeast Asia, among which APEC members Indonesia, Malaysia, Brunei and Australia figure prominently. Similarly, there might be several wholesale competitors for gas supply to CNPC and Sinopec even if they retain their parallel monopolies on pipelines. Gas from Kazakhstan, Turkmenistan or Western Siberia might be used to augment flows over the planned West-to-East pipeline. Alternatively, gas might be imported from Kovyktinskoye in Eastern Siberia or Sakhalin in Russia's Far East.[60]

The gas and electricity markets in China are vertically integrated only to the limited extent that gas is used to generate power. Each area has a single electric utility with a designated franchise area that can only obtain its gas from a single supplier. If the gas supplier raises its prices to cover inefficiencies, the electric utility is obliged to raise electric rates to accommodate higher gas prices,

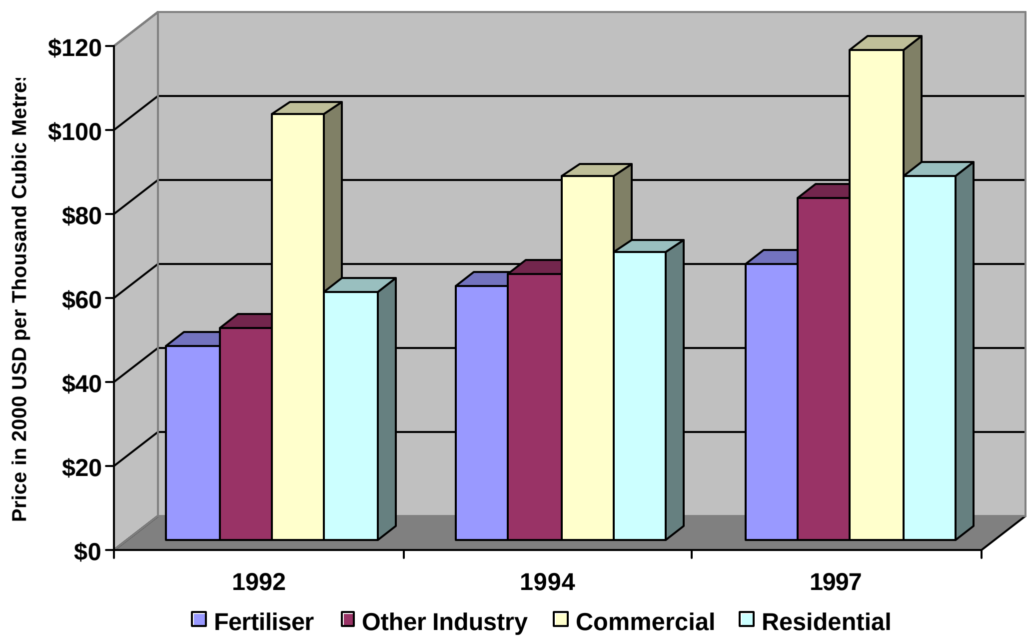
60 Fridley (2002), pages 48-52. Stern (2002), pages 251, 272.

or else to generate power with another fuel. However, gas fuels only about 2 percent of electric generating capacity in China and seems unlikely to account for more than 6 percent of power output even in 2020.[61] Thus, the impact of any gas sector inefficiencies on the power sector is apt to be quite limited. Nonetheless, the lack of competition in gas markets may impose real costs on users of electricity, since generators with gas-fired capacity may not always have the flexibility to shift to other fuels in response to higher gas prices. Moreover, if wholesale competition is implemented in the power sector, its effectiveness would be diminished by the inability of IPPs to compete on gas cost; the scope of competition would be limited to capital and operating costs.

PRICE TRENDS

Wellhead gas prices in China have increased substantially in recent years, more closely reflecting production costs, as the government has aimed to reduce public subsidies and encourage output. In Sichuan province, for example, the regulated wellhead price has increased in real US dollar terms by 42 percent for fertiliser producers, 61 percent for other industrial customers, 15 for commercial gas users, and 47 percent for residential gas users.[62]

Figure 36 Natural Gas Wellhead Prices in Sichuan Province, 1992-1997



Sources: Paik and Quan (1998), International Energy Agency, US Department of Commerce

In future, it is anticipated that gas prices may be moderated through competition between gas and other fuels. In the electricity sector, the price of gas may be moderated by competition from coal, which is the predominant fuel for power production. In fertiliser production, where gas is used as feedstock, competition will come from imported fertiliser. In residential heating and cooling, gas is likely to face some competition from electricity. Once a more elaborate network of gas pipelines is developed, it is anticipated that competition will also develop among gas sources.[63]

---

61 IEA (2002d), pages 124, 126.

62 IEA (2002d), page 180. Real prices calculated by dividing nominal prices in Chinese renminbi (RMB) by the prevailing exchange rate of RMB per USD and then by implicit GDP deflators from US Department of Commerce. Nominal increases from 1992 to 1997 were substantially greater (136 percent for fertiliser, 169 percent for other industry, 93 percent for commercial and 145 percent for residential). The real impact of these increases was muted by a sharp run-up in the exchange rate from 5.51 RMB/USD in 1992 to 8.62 RMB/USD in 1994 and 8.29 RMB/USD in 1997.

63 Lu (2003).

GAS MARKET REGULATIO N AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION AND DISTRIBUTION INFRASTRUCTURE

China has an extensive gas transmission system that spanned some 14,283 km in 2000.[64] But very substantial investments in new LNG facilities and pipelines will be needed if China's gas transportation infrastructure is to keep pace with anticipated growth in demand. The infrastructure will take a major leap forward with the West-to-East pipeline that was started in 2002. Phase I of the pipeline, to be completed in 2004 and reach its design capacity by 2005, will be able to transport 12 billion cubic metres of gas per year over 4200 km from Xinjiang province to Shanghai.[65]

The gas distribution network in China is well developed in major urban areas, with some 33,653 km of distribution pipeline in 22 provinces in 2000. Additional cities and towns are building gas distribution networks in anticipation of long-distance pipelines with which they can connect. The government estimates that some 50 cities will be served by gas distribution networks in 2004.[66]

INFRASTRUCTURE INVESTMENT INCENTIVES

Investment incentives for enhancement of China's gas transportation infrastructure appear to be quite adequate, at least for projects where the total delivered cost is not too high. For gas transmission pipelines built since 1997, the State Development and Reform Commission (SDRC) regulates transportation tariffs on the basis of real costs plus a standard after-tax internal rate of return (IRR). The standard IRR is currently set at 12 percent for domestic projects and 15 percent for international projects, assuming a 20-year project lifetime. For local distribution networks, local governments grant distribution companies a 30- to 50-year concession, and provincial governments add a distribution component to price based on proposals from gas distribution companies. Since the SDRC also sets wellhead gas prices based on estimated production costs and 12 percent IRR, delivered prices of natural gas should in principle reflect the costs of production and transport.[67]

However, the SDRC may limit the final gas price charged to different types of consumers, based upon an affordability criterion. For industrial customers, the affordability of gas is measured relative to the comparative costs of other fuels. For residential customers, affordability requires that energy expenditures not exceed 6 percent of household income. In practice, this may make it difficult for pipeline projects to actually recover their true costs, especially where the distances from wellhead to city gate are great. Incentives for some ambitious pipeline projects may thus be weaker than those that would be economically justified, making it harder to meet growing gas demand.[68]

On a more encouraging note, the official policy toward foreign direct investment in the gas sector has gradually become more positive over time. Foreign direct investment for construction and management of gas transmission pipelines has been officially encouraged since 1997. Foreign direct investment in construction and management of urban distribution networks for gas supply has been allowed since 2002 as long as Chinese investors own a majority stake.[69]

---

64 National Bureau of Statistics (2001).

65 China Energy Information Network (2003).

66 National Bureau of Statistics (2001).

67 Roberts and Gilboy (2001). IEA (2002d), pages 181-82.

68 *Ibid.*

69 Lu (2003).

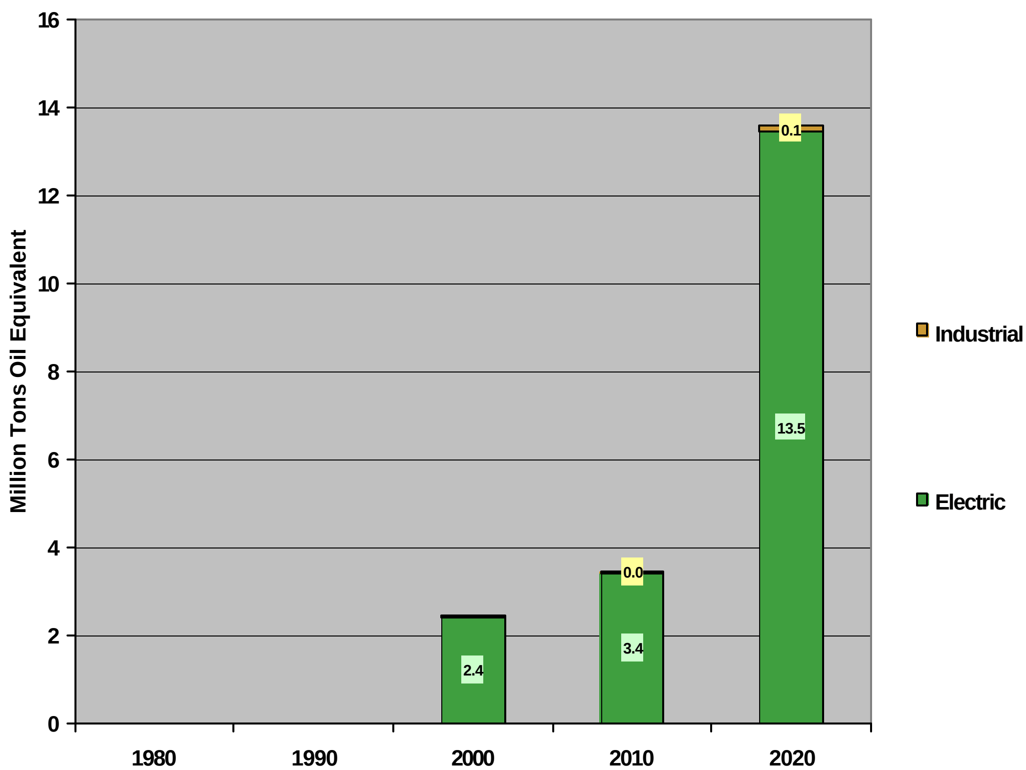
HONG KONG, CHINA

GAS MARKET SETTING[70]

Hong Kong relies on imports for all of its gas requirements.

- Domestic gas production, in the form of town gas produced from imported oil, is projected to remain stable at around current levels of 0.5 Mtoe through 2020.
- Imports of natural gas are projected to increase nearly seven-fold from 1.9 Mtoe in 2000 to 13.0 Mtoe in 2020
- Primary supply of gas to the domestic economy is projected to quintuple from 2.5 Mtoe in 2000 to 13.5 Mtoe in 2020, with average annual growth of 3.5 percent in the decade from 2000 to 2010 accelerating to 14.6 percent in the decade from 2010 to 2020.

Figure 37 Evolution of Natural Gas Use in Hong Kong, 1980-2020



Virtually all of Hong Kong's natural gas use takes place in the electric power sector, and this situation is expected to persist indefinitely, despite very small amounts of industrial gas use.

- Use of gas for electric power generation is projected to grow more than five-fold from 2.4 Mtoe in 2000 to 13.5 Mtoe in 2020, its share of natural gas demand remaining near 100 percent.

---

70 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

All of Hong Kong's natural gas is imported by pipeline from the Yacheng gas field in the South China Sea, mainly for use in electric power plants. The gas is produced by the China National Offshore Oil Corporation (CNOOC) and transported over a pipeline which CNOOC owns in consortium with pipeline operator Atlantic Richfield and the Kuwait Foreign Petroleum Exploration Company. The power plants, including 1,875 MW of gas-fired capacity at Black Point and 1,355 MW of gas-capable capacity at Castle Peak, are operated by CLP Power Hong Kong, formerly known as China Light and Power, in partnership with Exxon Energy Limited.[71]

Residential and commercial gas needs are met by town gas and liquefied petroleum gas (LPG). The Hong Kong and China Gas Company, which is also known as Towngas, produces the town gas from imported oil and distributes it to some 1.4 million customers. About 95 percent of the town gas is produced at the Tai Po plant, while the remainder is produced at the older Ma Tau Kow plant. The Towngas network of 2,828 km of pipeline makes gas available to 85 percent of Hong Kong's households. About three-fourths of small customers' gas needs are met by town gas over this network; the remaining fourth are met by LPG supplied in canisters by oil companies.[72]

PRINCIPAL PLAYERS IN HONG KONG'S GAS MARKET

External Producers from which Hong Kong Imports Gas
Natural Gas: China National Offshore Oil Corporation (CNOOC)
Oil for Town Gas: Caltex, China Resources, Esso, Mobil, Shell
Oil for LPG: Caltex, China Resources, Esso, Mobil, Shell

Owner and Operator of Gas Transmission and Distribution Pipelines in Hong Kong
Natural Gas: Consortium of China National Offshore Oil Corporation,
Atlantic Richfield Company and Kuwait Foreign Petroleum Exploration Company
Town Gas: Hong Kong and China Gas Company (Towngas)

Gas Retailers in Hong Kong
Hong Kong and China Gas Company (Towngas)

Sources: Information Services Department, CLP Power

UNBUNDLING AND THIRD PARTY ACCESS

The functions of Hong Kong's gas market are not generally unbundled. Town gas for residential and commercial customers is produced, transported and distributed by the same company, Towngas. Since there are no competing producers, there is no third party access to the town gas transmission or distribution grids. On the other hand, LPG suppliers can bypass the gas transportation network in providing an alternative form of gas to these customers. Natural gas for electricity generation is produced by just one company, the China National Offshore Oil Corporation, which also has a major financial interest in transportation of the gas.

---

[71] Information Services Department (2002). The Castle Peak Power Company Ltd (CAPCO) is owned 40 percent by CLP Power and 60 percent by Exxon Energy. The Black Point Power Company Ltd has a similar ownership arrangement.

[72] *Ibid.* Hong Kong and China Gas Company (2000).

The gas industry in Hong Kong is not subject to economic regulation. The Electrical and Mechanical Services Department (EMSD) establishes and implements safety standards "in the importation, manufacture, storage, transport, supply and use" of town gas, natural gas, and liquefied petroleum gas. But it does not regulate the prices or conditions under which they may be obtained, or otherwise promote competition among various types or suppliers of gas.[73]

MARKET MODEL AND COMPETITION

For residential and commercial customers, the gas market in Hong Kong appears to resemble a hybrid between the vertically integrated monopoly model and the customer choice model. The Hong Kong and China Gas Company produces, transports and distributes town gas to these customers in an integrated fashion, and it has no competitors in town gas supply. However, the company does not enjoy its town gas monopoly as a matter of policy or law. It faces competition for gas customers from suppliers of LPG, who have gained a quarter of the market. It also faces potential competition, in theory, from other town gas providers, but none are on the horizon. This is probably due to natural monopoly characteristics of the pipeline grid that Towngas controls.

For electric power and large industrial customers, the gas market in Hong Kong appears more clearly to resemble the vertically integrated monopoly model. In principle, there would appear to be wholesale competition, in the sense that CPL Power is presumably free to buy gas from the least costly source available. In practice, however, there is only a single natural gas supplier in Hong Kong so far, and it is not clear whether competing gas sources will materialise.

Hong Kong's gas and electricity markets are vertically integrated to significant degree. About a quarter of the economy's power is generated from natural gas. All the gas-fired power plants are owned by the same partners, CPL Power and Exxon Energy Ltd. These plants obtain gas from just one source, the China National Offshore Oil Corporation (CNOOC), which has a legal monopoly on all offshore oil and gas development in China. The pipeline for the gas is owned by a consortium of CNOOC, operator Atlantic Richfield Company (ARCO) and the Kuwait Foreign Petroleum Exploration Company.[74] At least until 2008, when the power market may be open to new entrants, CPL Power will share the market with just one other firm, the Hong Kong Electric Company. If there is still only a single gas supplier at that time, with all power producers obtaining gas from the same source, the effective scope for competition among them will remain limited.

GAS MARKET REGULATIO N AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

The Hong Kong and China Gas Company had some 124 km of town gas transmission pipeline and 2,920 km of town gas distribution pipeline in 2002. The pipeline that brings natural gas from CNOOC's offshore Yacheng field to Hong Kong's Black Point power station is 780 km long.[75]

The town gas distribution network in Hong Kong is well developed. About 85 percent of households have access to the network, and the number of customers should grow with the completion of high pressure and intermediate pressure pipelines that are now under construction. The town gas network is expected to expand by roughly 350 km over a five-year period.

[73] Electrical and Mechanical Services Department (2002a).

[74] APERC (2002b), page 39. Information Services Department (2002). CLP and Exxon Energy Ltd (2001a), pages 2, 4. CLP Power and Exxon Energy Ltd (2001b), pages 4, 8. CPL Power uses gas at the 1,875 MW Black Point station and in 1,355 MW of capacity at the Castle Peak station. This totals 28 percent of the 11,568 MW of capacity in service.

[75] Electrical and Mechanical Services Department (2002b).

INFRASTRUCTURE INVESTMENT INCENTIVES

Hong Kong's incentives for investment in transmission and distribution infrastructure appear to be adequate, in view of the infrastructure that has been built to date. As there is no legal franchise for such infrastructure, and no regulated return on its construction, the incentives would appear to derive from the economies of supplying fuel via a network to a densely populated city. Nonetheless, the Hong Kong and China Gas Company is making significant enhancements to its pipeline grid for town gas serving small customers. With respect to gas for power production, pipeline costs represent a small portion of the overall costs of building, fuelling and operating electric power plants, so pipelines should continue to be built to such plants as required.

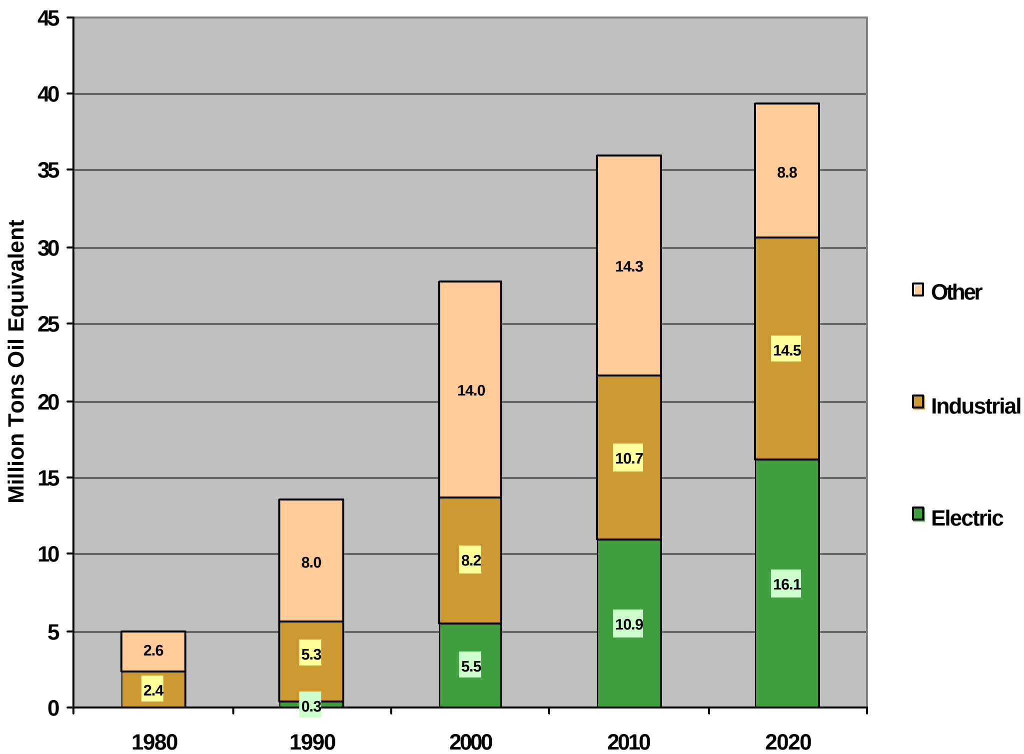
INDONESIA

GAS MARKET SETTING[76]

Indonesia is a major gas producer and exporter, with gas supplied to the economy solely from domestic production.

- Total gas production is projected to increase from 67.8 Mtoe in 2000 to 90.7 Mtoe in 2020, but the share of production exported is expected to decline slightly from 59 percent to 57 percent.
- Primary supply of gas to the domestic economy is projected to grow from 27.7 Mtoe in 2000 to 39.4 Mtoe in 2020, with average annual growth of 2.6 percent in the decade from 2000 to 2010 and just 0.9 percent from 2010 to 2020.

Figure 38 Evolution of Natural Gas Use in Indonesia, 1980-2020



Very nearly all of Indonesia's natural gas use is devoted to energy transformation and industry. About half the economy's gas is used in non-electric energy transformation, of which most goes to crude oil production and smaller amounts to oil refining and natural gas liquids production. Of the remaining half, about two-fifths goes to electricity generation and three-fifths to industry. The relative importance of power generation and industry in the gas market are expected to grow.

- Use of gas for electric power generation is projected nearly to triple from 5.5 Mtoe in 2000 to 16.1 Mtoe in 2000, so that its share of overall gas demand doubles from 20 percent to 41 percent.

[76] Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Industrial use of gas should somewhat less than double from 8.2 Mtoe in 2000 to 14.5 Mtoe in 2020, while its market share grows from 30 percent to 37 percent.
- "Other" gas use, primarily for crude oil production, is expected to drop sharply from 14.0 Mtoe in 2000 to 8.8 Mtoe in 2020, so that its share of the gas market falls by more than half from 51 percent to 22 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Indonesia's gas industry is dominated by Pertamina, the national oil and gas company, which has a monopoly over gas production and also controls perhaps two-thirds of the economy's gas transmission grid. Formed by the merger of two state-owned oil companies in 1968, it is the only authorized supplier of gas to power generation and petrochemical plants. Law 44, promulgated in 1960, stipulates that oil and natural gas can only be exploited through a state enterprise. Pertamina collaborates with international operators in exploration, development, and production, mostly at offshore fields. It has production sharing arrangements with several major international oil companies, but these arrangements do not alter Pertamina's essential monopoly over production.

PRINCIPAL PLAYERS IN INDONESIA'S GAS MARKET

Gas Producers in Indonesia

Pertamina (in production sharing contracts with Arco, Asamera, BP, Caltex, Conoco, ExxonMobil, Gulf Indonesia Resources, Total, Unocal, and Vico)

Owners and Operators of Gas Transmission Pipelines in Indonesia

Pertamina, Perusahaan Gas Negara (PGN), PT TransJava Gas Pipeline Ltd

Owners and Operators of Gas Distribution Pipelines in Indonesia

Perusahaan Gas Negara (PGN) operating through local distribution branches serving Jakarta, Bogor, Medan, Surabaya and Cirebon

Sources: APERC, Pertamina, PGN

Transmission of gas is mainly performed by Pertamina and by Perusahaan Gas Negara (PGN), which obtains all its gas from Pertamina and is also state-owned. Pertamina had about 3,800 km of pipeline in 2001, all of which was transmission pipeline. PGN had 3,022 km of pipeline in 2000, of which about two-thirds was for transmission and one-third was for distribution. So the gas transmission network was held roughly two-thirds by Pertamina and one-third by PGN. Major gas transmission projects are often undertaken through joint ventures with private firms. For example, Pertamina's pipeline from the offshore West Natuna field to Singapore was built by the West Natuna Transportation System Consortium, with participation by Conoco, Gulf and Premier; Conoco is in charge of the pipeline's operation. A pipeline from the offshore Pagerungan site to the Java town of Gresik was built by the independent PT TransJava Gas Pipeline.[77]

Distribution of gas in Indonesia is performed exclusively by PGN. The company operates largely through local distribution branches serving five major metropolitan areas. These distribution branches are the sole suppliers of gas in their respective regions, except for gas consumed by large

[77] Pertamina (2003). PGN (2001). IEEJ (2002b), page 39. Observation on PGN's pipeline mix is based on IEEJ's report that of its 2,747 km of pipeline in 1998, 1,776 km was high-pressure pipeline and 971 km was low-pressure pipeline. Applying this ratio, PGN would have some 1,954 km of transmission pipeline in 2000. The transmission network in 2001 would then extend at least 3,800 + 1,954 = 5,754 km of which Pertamina's 3,800 km would represent 66 percent.

petrochemical plants, which obtain their gas directly from Pertamina's transmission grid. The distribution grid is quite limited in geographic scope and serves mainly large customers. In 2000, there were 594 industrial customers consuming most of the natural gas, as well as 1,053 commercial customers and 42,991 residential customers (in an economy with some 210 million people).[78]

UNBUNDLING AND THIRD PARTY ACCESS

The functions of Indonesia's gas market are not unbundled to any significant extent. Pertamina controls all gas production and about two-thirds of all gas transmission pipelines. PGN controls the remainder of the transmission pipelines and all distribution. However, under the Law Concerning Oil and Natural Gas that was promulgated in November 2001, entities engaging in the upstream activities of exploration and production are flatly prohibited from engaging in the downstream activities of processing, transportation, storage and trading. Distinct entities may be established under the same holding company but must be functionally separated. Pertamina will have separate divisions for upstream activities, downstream activities and geothermal energy. Transmission and distribution systems will also be functionally unbundled from each other by restructuring PGN into a holding company with four distinct subsidiaries. One subsidiary will focus on expansion of the distribution grids in West Java and elsewhere. A separate subsidiary will focus on development and operation of transmission systems. Other subsidiaries will produce biogas from municipal waste in Jakarta and promote combined heat and power plants.[79]

As there have been no competing producers, there has been no third party access to the transmission or distribution grids. However, the new Oil and Gas Law will remove Pertamina's monopoly on upstream oil development by late 2003. As a result, the government is considering a proposal to allow third party access to transmission pipelines insofar as they have spare capacity. In addition, Pertamina and BP Indonesia have agreed to release their exclusive right to supply gas to East Java, in view of their declining gas reserves, and to allow third party access to the Trans-Java Gas Pipeline. But details of the access regime, such as how to determine the amount of spare capacity available to third parties and the rates charged for its use, have not been established.

MARKET MODEL AND COMPETITION

The Indonesian gas market most closely resembles the vertically integrated monopoly model. Pertamina has a legal monopoly on gas production and also controls more than half of the high-pressure gas transmission network. The remainder of the transmission network is owned and operated mainly by PGN, which monopolises gas distribution. PGN obtains its gas solely from Pertamina, and the two firms presumably cooperate closely since both are state-owned. Production, transmission and distribution of gas are thus all integrated in two state-owned companies.

However, the 2001 Oil and Gas Law seems likely to move the gas market toward the wholesale competition model. Article 3 of the law stipulates that the exploration and exploitation of oil and gas (upstream activities) should be "highly competitive" and that processing, transportation, storage and trading (downstream activities) should be conducted through a mechanism that allows "fair and transparent business competition." The law will remove Pertamina's monopoly on upstream oil development within two years and its monopoly on distribution of petroleum products within four years. Thus, as of late 2003, Pertamina is no longer required to be included in production sharing contracts, which will henceforth be awarded and supervised by an independent regulator called the Implementing Body.[80] With new production contracts awarded on a competitive basis, wholesale competition should evolve as overall production expands over time.

Indonesia's gas market is vertically integrated with its electricity market to a great extent. Roughly three-eighths of the economy's electric generating capacity was gas-fired in 1999. The power sector is dominated by the integrated state public utility, Perusahaan Listrik Negara (PLN).

---

78 APERC (2000c), pages 52-53. International Energy Agency (1996), page 131.

79 Republic of Indonesia, People's Legislative Assembly (2001a, 2001b), Articles 9 and 10.

80 *Ibid.*, Article 3. APERC (2002b), page 45.

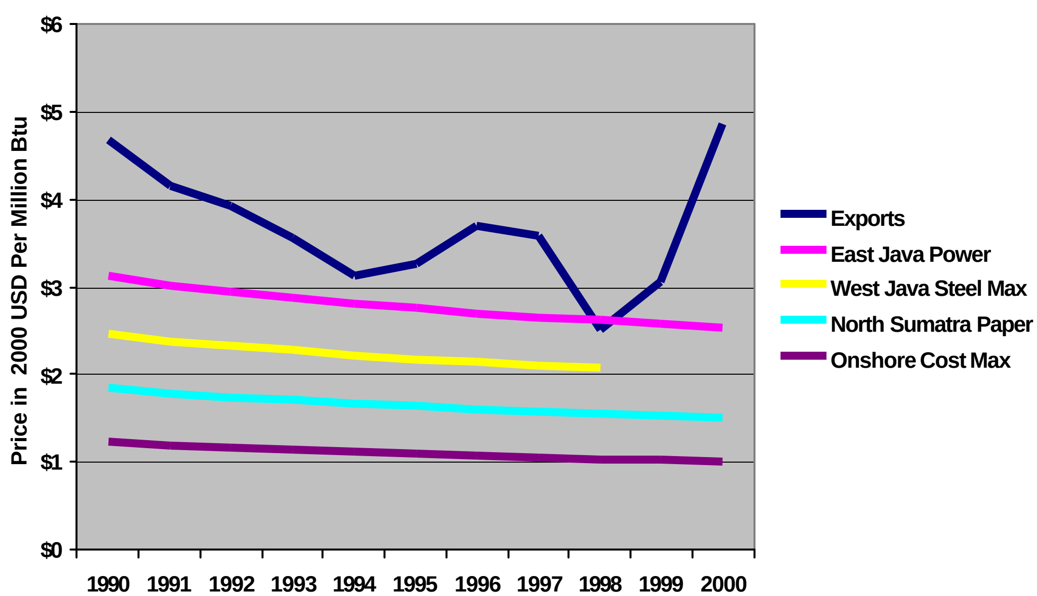
Independent power producers (IPPs) have been allowed since 1993 and own about 9 percent of the economy's electrical generating capacity. This has brought wholesale competition to the power sector, which should be further promoted by a new electricity law that was promulgated in 2002. But all the output of IPPs must be sold through PLN, which retains a monopoly on electricity transmission, distribution and retailing.[81] Both PLN and IPPs must purchase gas from the same producer, Pertamina, so generating costs from their gas-fired power plants will be changed by similar amounts if Pertamina raises or lowers its prices. Also, in view of the large share of gas-fired generating capacity, power producers have limited flexibility to shift to other fuels.

It follows that as the sole supplier of gas to the economy, Pertamina has substantial market power to pass on the costs of inefficiencies that might arise in gas production and processing, as well as in the operation of pipelines, in higher gas prices to power producers. Alternatively, since Pertamina is owned by the state, the government may decide to subsidise gas prices to power producers. As the sole supplier of electricity to final customers, PLN can pass on increased costs of gas and power production in rates, or decline to pass on reduced costs of gas and power production in rates, regardless of whether the power is generated from its own plants or from IPPs. But as the economy grows and competition in the gas sector grows over time pursuant to the 2001 reforms, competing power producers will eventually be able to shop around for the least costly gas, and the effective vertical integration between the gas and electricity markets should gradually abate.

PRICE TRENDS

Gas prices in Indonesia, which are fixed over long periods of time by regulation, have generally been below those that would prevail in a properly functioning marketplace. This can be seen by comparing the market-determined prices for gas exports to Asia with the regulated domestic prices paid by power producers and industry. During the 1990s, the average gas price paid by electricity generators in East Java was barely three quarters of the export price, while the gas price paid by West Java steel makers and North Sumatra paper producers averaged half the export price or less.[82]

Figure 39 Comparison of Gas Prices and Costs in Indonesia, 1990-2000



Sources: APERC, Ministry of Energy and Mineral Resources

81 IEEJ (2002a), pages 55-59. Of 20,722 MW of electrical generating capacity in 1999, 1,890 MW was owned by IPPs.

82 Real prices calculated by dividing selected end-use prices in current US$ from APERC (2001a), page 82, and export and production costs from Ministry of Energy and Mineral Resources (2002), pages 30-32, by implicit GDP deflators from US Department of Commerce.

The low domestic gas prices tend both to promote inefficient gas consumption and to make investment in domestic gas transportation infrastructure much less attractive financially than investment in infrastructure for gas exports. While this may have little practical impact on the gas market as long as decisions on infrastructure expansion are made by the government and implemented by Pertamina or PGN, the impact on state revenues would appear to be substantial. On the other hand, most domestic prices appear to have been consistently well above the cost of onshore gas production, so serving the domestic gas market seems likely still to be profitable.

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Indonesia had about 6,822 km of gas transmission and distribution pipelines in 2001. Because gas production is dispersed over several different islands of the Indonesian archipelago, the pipelines are not linked in a unified transmission grid. Rather, there are distinct transmission systems delivering gas from production fields to large users and distribution grids in Sumatra, east and west Java, northeast and southeast Kalimantan, Banyu Island, and Sulawesi. There are high-pressure pipelines for exporting gas to Malaysia and Singapore, as well as two LNG terminals for gas exports to Japan, Korea, and Chinese Taipei.[83]

Figure 40 Existing and Planned Gas Pipeline Infrastructure in Indonesia

Sources: APERC (2000c), PGN, Ministry of Energy and Mineral Resources

Indonesia anticipates significant expansion of its high-pressure gas transmission grid and LNG facilities to accommodate growth in gas production, export and use. A 481 km pipeline costing US$401 million would carry 350 million cubic feet (9.9 million cubic metres) per day from northern

83 APERC (2000c), page 32.

Sumatra to Singapore. Some 550 km of pipeline costing US$640 million would carry 600 Mcf (17.0 Mcm) per day from southern Sumatra to West Java. A 1,100 km pipeline costing US$1.1 billion would carry 700 Mcf (19.8 Mcm) daily from East Kalimantan to East Java. In all, some 3,123 km of new gas transmission lines with a capacity of 2,375 Mcf (67.3 Mcm) per day are planned for completion by 2010 at an estimated cost of nearly US$2.6 billion.[84] There will also be a new LNG facility in West Java to receive 550 Mcf (15.6 Mcm) per day of gas from Tangguh for domestic use starting in 2005.[85]

Gas is distributed in five major metropolitan areas, but only to large electric power producers, petrochemical firms, and other industrial firms. There are no plans to extend the distribution grid to residential or commercial customers as space heating requirements are negligible, fuels other than gas are used for cooking, and air conditioning is readily powered by electricity. There are, however, plans to build new distribution grids in west Java, east and central Java, and Batam Island off the southern tip of the Malaysian Peninsula by 2010. This would entail investment of some US$250 million for 504 km of distribution pipeline carrying 1,280 Mcf per day.[86]

INFRASTRUCTURE INVESTMENT INCENTIVES

Indonesia's incentives for investment in transmission infrastructure for delivering gas to export markets appear to be adequate. Since prices for exported gas are market-determined, facilities for the production and transmission of such gas will presumably be built whenever economical.

By contrast, availability of capital for investment in transmission and distribution infrastructure for domestic gas delivery may be unduly limited. The prices paid by industrial customers, such as fertiliser and steel producers, are well below market levels. Thus, existing infrastructure may be congested by demand that would disappear if customers were paying a price based on cost, so that existing distribution grids are larger than currently necessary. At the same time, artificially low prices tend to restrict the availability of private investment capital for building new distribution grids where needed and extending transmission pipelines to meet them. The practical impact may be small since decisions on expansion of transportation infrastructure can be implemented by the government through Pertamina and PGN. But artificially low domestic gas prices would seem to encourage inefficient use of gas by consumers and also to adversely affect state revenues.

If domestic gas prices are raised toward market levels as intended by government policy, the availability of private capital for expanding domestic gas transmission and distribution infrastructure should improve significantly. This will largely depend upon the actions of the downstream Regulating Body that is to set tariffs for natural gas transportation and distribution and for purchase of natural gas by small residential and commercial customers.

---

[84] American Embassy Jakarta (2002). The pipeline from northern Sumatra to Singapore includes a 135 km segment from Grissik to Sakernan, a 286 km segment from Sakernan to Batam, and a 60 km segment from Batam to Singapore. The pipeline from southern Sumatra to West Java includes a 370 km segment from Pagar Dewa to Cilegon and a 180 km segment from Pagar Dewa to Grissik. Also included in the estimated totals are a 222 km pipeline costing $50 million that could move 50 Mcf per day from Jambi to Lampung, a 100 km pipeline costing $35 million that could move 50 Mcfd from Samarinda to Balikpapan, a 390 km pipeline costing $210 million that could move 360 Mcfd from Gresik to Semarang, a 200 km pipeline costing $80 million that could move 65 Mcfd from Sengkang to Ujung Pandang, and an 80 km pipeline costing $80 million that could move 200 Mcfd from Kondur to Minas.

[85] Jakarta Post (2002).

[86] American Embassy Jakarta (2002). The west Java system would extend 174 km, cost $120 million and move 550 Mcfd. The east and central Java system would extend 300 km, cost $105 million and move 700 Mcfd. The Batam Island system would extend 30 km, cost $25 million and move 30 Mcfd.

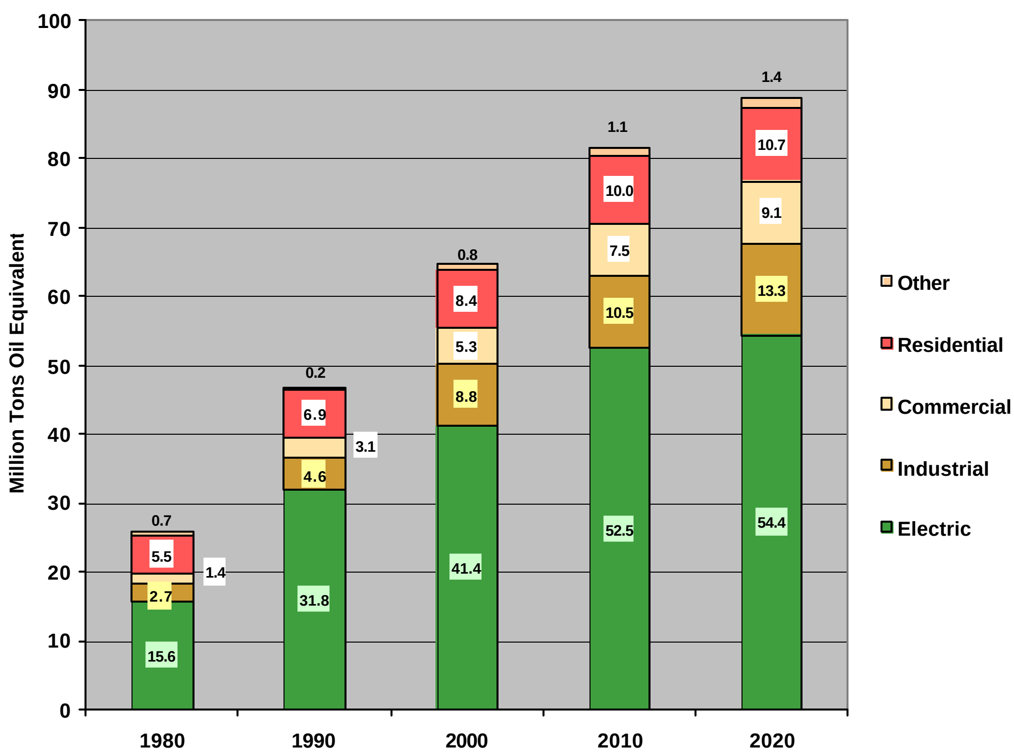
JAPAN

GAS MARKET SETTING[87]

Japan produces a small amount of gas but relies on imports for almost all of its gas needs.

- Domestic gas production is projected to decline from 4.4 Mtoe in 2000 (including 1.6 Mtoe of natural gas and 2.8 Mtoe of town gas produced mainly from imported oil) to 2.9 Mtoe in 2020 (all town gas, still mainly from imported oil), so that the share of gas demand met by domestic production declines from 6 to 3 percent.
- Imports of gas are projected to grow from 60.3 Mtoe in 2000 (all as LNG) to 86.1 Mtoe in 2020 (mainly as LNG, with possible pipeline gas from Sakhalin, Russia).
- Primary supply of gas to the domestic economy is projected to increase from 64.7 Mtoe in 2000 to 88.9 Mtoe in 2020, with yearly growth averaging 2.3 percent in the decade from 2000 to 2010 and just 0.9 percent in the decade from 2010 to 2020.

Figure 41 Evolution of Natural Gas Use in Japan, 1980-2020



Japan's natural gas use is fairly diversified. While more than three fifths of gas demand originates in the electric power sector, substantial gas use occurs in the industrial, commercial and residential sectors as well.

[87] Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

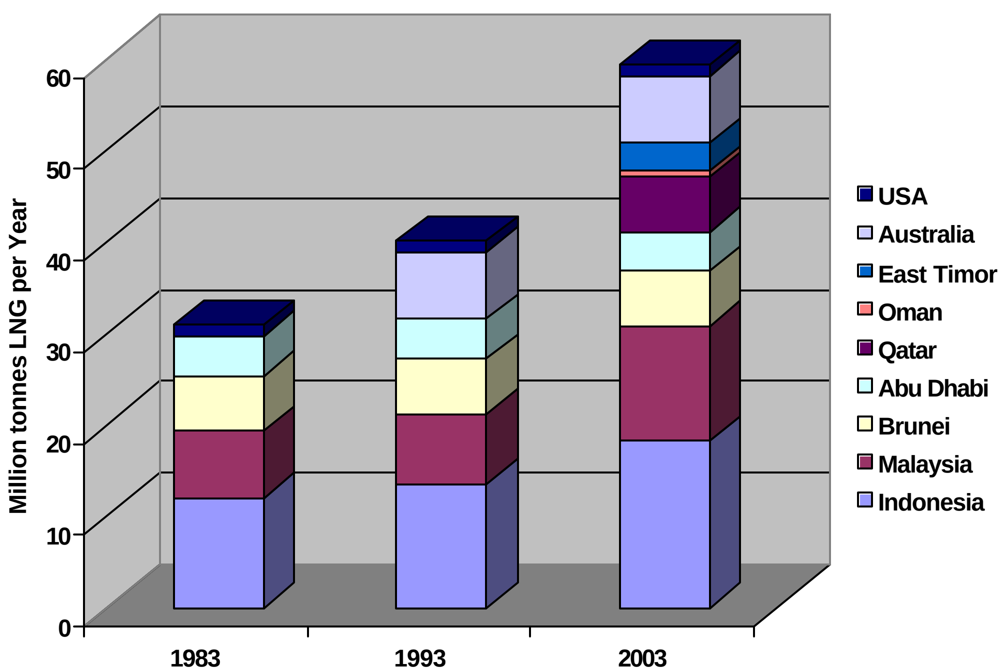
- Use of gas for electric power generation is expected to grow at a rather slow pace from 41.4 Mtoe in 2000 to 54.4 Mtoe in 2020, so that the power sector's share of overall gas use declines slightly from 64 percent to 61 percent.
- Industrial gas use projected to grow by half, from 8.8 Mtoe in 2000 to 13.3 Mtoe in 2020, with its share of the gas market rising from 11 percent to 15 percent.
- Commercial gas use should also increase substantially, from 5.3 Mtoe in 2000 to 9.1 Mtoe in 2020, with its gas market share growing from 8 percent to 10 percent.
- Residential gas use is expected to increase modestly, from 8.4 Mtoe in 2000 to 10.7 Mtoe in 2020, its share of gas demand slipping from 13 percent to 12 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Japan has very limited gas production. Most of the economy's gas is imported through LNG terminals, which constitute an essential element of the gas transportation infrastructure, together with gas pipelines. In addition, most of the gas is purchased under long-term take-or-pay contracts. About three-fifths of the gas comes from other Asian APEC economies including Indonesia (32 percent of long-term contract volumes), Malaysia (21 percent) and Brunei Darussalam (10 percent). Substantial amounts also come from APEC members Australia (12 percent of long-term contract amounts) and United States (2 percent). Finally, roughly a quarter of Japan's gas imports come from non-APEC producers including Abu Dhabi (with 7 percent of volumes under long-term contract), Qatar (10 percent), Oman (1 percent) and East Timor (5 percent).[88]

Figure 42 Evolution of Japan's LNG Sources under Long-Term Contracts



Source: Institute of Energy Economics, Japan

[88] IEEJ (2002b), slides 47-49.

Japan's LNG facilities are owned and controlled by three different types of entities: gas utilities with regional franchises to supply gas, electric utilities with regional franchises to supply power, and joint enterprises formed by gas utilities, electric utilities, municipal governments and steel companies. In practice, most LNG in Japan is procured by consortia of regional gas and electric utilities. In the Kanto region where Tokyo is located, there is joint procurement of LNG by Tokyo Electric Power Company and Tokyo Gas Company. In the Kansai region where Kyoto and Osaka are located, there is joint procurement of LNG by Kansai Electric Power Company and Osaka Gas Company. Other alliances exist between Chubu Electric and Toho Gas and between Kyushu Electric and Saibu Gas.[89]

PRINCIPAL PLAYERS IN JAPAN'S GAS MARKET

External Producers from which Japan Imports Gas

Pertamina (Indonesia), Petronas (Malaysia), Brunei LNG, Abu Dhabi Gas Liquefaction,
Qatar LNG, Oman LNG, Darwin LNG (East Timor),
Phillips Alaska Natural Gas (United States), Marathon Oil (United States),
BP Development Australia, Chevron Australia, Shell Development Australia,
Woodside Petroleum (Australia), Japan Australia LNG

Major Owners and Operators of LNG Terminals and Transmission Pipelines in Japan

Regional Gas Utilities:
Tokyo Gas Company, Toho Gas Company,
Osaka Gas Company, Saibu Gas Company
Regional Electric Utilities:
Tokyo Electric Power Company, Chubu Electric Power Company,
Kansai Electric Power Company, Kyushu Electric Power Company,
Tohoku Electric Power Company, Chugoku Electric Power Company

Additional Owners and Operators of LNG Terminals in Japan

Joint Enterprises of Gas Utilities, Electric Utilities, Municipalities, Steel Companies:
Higashi-Niigata, Shimizu, Chita-LNG, Oita, Tobata

Additional Owners and Operators of Gas Transmission Pipelines in Japan

Domestic Gas Developers:
JAPEX (Japan Petroleum Exploration Company), Teikoku Oil Company

Owners and Operators of Gas Distribution Pipelines in Japan

Regional Gas Utilities:
Tokyo Gas Company, Toho Gas Company
Osaka Gas Company, Saibu Gas Company
Local Distribution Utilities:
About 234 independent companies (62 municipal and 172 private)

Source: Institute of Energy Economics, Japan

Japan's gas pipeline network is also owned and controlled by three different types of entities: regional gas and electric utilities and domestic gas development companies. However, the bulk of the gas pipeline network is controlled by regional gas utilities. Electric utility interest in gas pipelines is generally limited to short pipelines that link LNG facilities with gas-fired power plants. The Ministry of Economy, Trade and Industry (METI) regulates gas tariffs and pipeline access through its Office of Natural Gas Regulation.

89 Institute of Energy Economics, Japan (2002c)

UNBUNDLING AND THIRD PARTY ACCESS

In the Japanese gas market, production is almost entirely unbundled from transport. This is not the case for domestic gas producers (JAPEX and Teikoku), which also own gas pipelines, but domestic production supplies only a few percent of the overall gas market. The bulk of production is provided by competing suppliers abroad, while the bulk of transport is provided by the Japanese gas and electric utilities and utility-municipal-steel consortia.

In addition, long-distance transmission of gas in Japan is partially unbundled from local distribution. The regional gas utilities own and operate gas distribution networks in addition to gas transmission pipelines and LNG facilities, in some case through local distribution affiliates. But there are also some 240 independent gas distribution companies that do not have any long-distance transmission function. The regional gas utilities provide transportation services to other entities that can procure natural gas, and it is foreseen that additional gas companies will be requested to provide transportation services and file transportation tariffs. However, there is not strict unbundling of accounts between transmission and distribution functions in these utilities.

Within the gas transmission function, there is very limited unbundling of LNG facilities and gas pipelines. It is true that the utility-municipal-steel consortia own only LNG facilities, while domestic gas developers own only pipelines. But the regional gas utilities and the regional electric utilities operate both LNG facilities and pipelines, and these utilities account for most gas transport.

With respect to gas pipelines owned by major gas utilities, there is regulated third-party access for competing gas suppliers and large gas customers. The 1995 amendments to the gas and electric industry laws required the gas utilities to allow pipeline access to competing suppliers on non-discriminatory terms. The 1995 amendments also made gas customers using more than 2 million cubic meters (92 terajoules) per annum eligible to choose their supplier. The 1999 amendments to the gas and electric industry laws further extended pipeline access to large volume customers using over 1 million cubic meters (46 terajoules) of gas per annum. The 1999 amendments also required the four large gas utilities to disclose rulebooks for retail third-party access, putting competing suppliers in a better position to negotiate contracts.[90]

However, with respect to the bulk of the gas transport system in Japan, provisions for third-party access have been absent. This is most evident in the case of LNG facilities, which are legally considered analogous to private factories. The gas and electric utilities that own and operate LNG facilities are not obliged to allow the use of such facilities by competitors. Gas pipelines other than those owned by the four major gas utilities are not required to provide access to competitors either.

Looking forward, there are signs that third-party access to gas transportation services in Japan may be expanded. The Forum on Gas Market Reform, organised by the Ministry of Economy, Trade and Industry (METI), recommended in April 2002 that owners of LNG facilities who intend to enter the gas market make public the amount of capacity at such facilities that is not being utilised, that they negotiate for use of such capacity by third parties, and that they inform third parties of the reasons that access to spare capacity is denied, if that is the case. The Forum also recommended that access to natural gas pipelines be extended to all customers, rather than just large industrial and utility customers, and that access be provided to all pipelines, rather than just those owned by gas companies. The Urban Heat Energy Subcommittee of METI's Advisory Committee for Natural Resources and Energy took these proposals under consideration in September 2002 and endorsed them in February 2003. The Diet then incorporated them in an amended Gas Utility Industry Law in June 2003. If they are fully implemented, Japan will have negotiated third-party access for LNG facilities and regulated third-party access for gas pipelines.[91]

The Urban Heat Energy Subcommittee also laid out a specific timetable for expanding choice of gas suppliers in the retail market. It recommended that retail choice be introduced for industrial and commercial firms with an annual demand of 500,000 cubic metres or more in about 2004 and

90 Institute of Energy Economics, Japan (2002b).

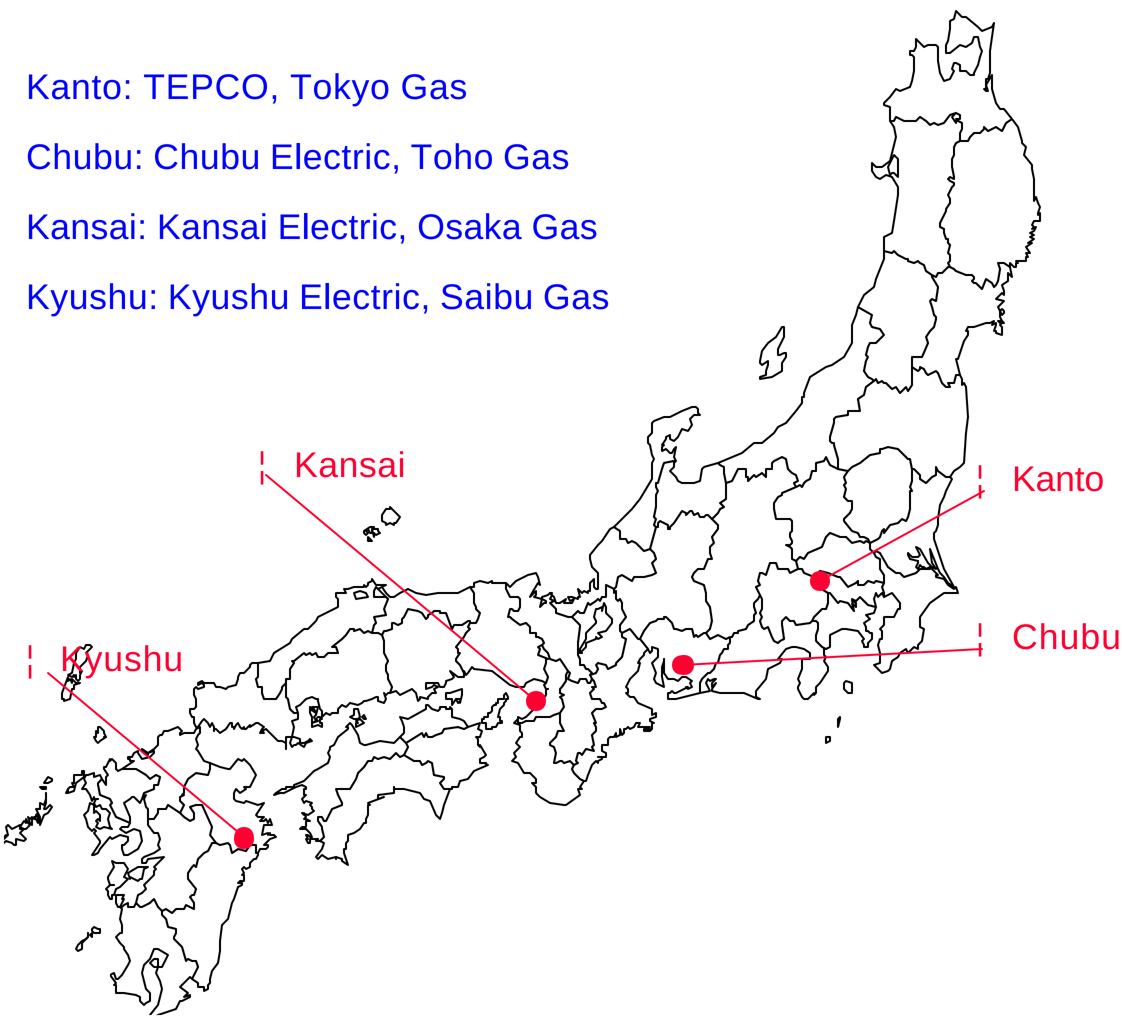
91 Government of Japan and Government of the United States (2002). METI Gas Market Division (2003).

for firms with an annual demand of 100,000 cubic metres or more in about 2007. This would expand the scope of the liberalised market from 40 to 50 percent of gas demand for the ten largest gas utilities (which account for 85 percent of overall gas demand). The amended Gas Utility Industry Law adopted by the Diet in June 2003 in fact advances the date for completing this expansion of the competitive market to April 2005. For household and small commercial users with lower demand, the Subcommittee recommended that a decision on retail choice be made in light of the results of retail liberalisation for larger customers and in other energy sectors.[92]

MARKET MODEL AND COMPETITION

Japan's gas market would seem to fit most closely the wholesale competition model. However, instead of one principal wholesale buyer of gas in each region, there are two: the franchised gas utility and the franchised electric utility. In practice, the market in each area is split between the two buyers mainly according to end use, with electric utilities buying gas to fuel their gas-fired power plants and gas utilities buying gas to serve industrial, commercial and residential customers. There is substantial wholesale competition, as both gas and electric utilities buy gas from competing foreign suppliers through their LNG facilities.

Figure 43 Regional Markets for Gas and Electricity in Japan



92 METI Gas Market Division (2003). Government of Japan (2003).

At the same time, several aspects of Japan's gas market fit the retail competition model, at least with respect to large customers. As described above, both major industrial firms and electric utilities have access to competing suppliers on gas pipelines. More importantly, electric utilities and a large steel maker import gas directly from competing foreign suppliers through their own LNG facilities. If access to LNG facilities and pipelines expands according to the recommendations of the Forum on Gas Market Reform, the retail competition model may come to predominate.

There is a high degree of vertical integration between gas and electricity markets in Japan, which is unique among APEC economies in that electric utilities directly import the gas they use. About 26 percent of the economy's electric generating capacity in 2000 was fuelled by imported natural gas.[93] The major electric utilities control the LNG facilities through which fuel is imported for gas-fired powerplants. Neither they nor the major gas utilities that import LNG are obliged to offer use of their LNG facilities to independent power producers, and no IPP has attempted to build LNG facilities of its own. Such facilities have scale economies which are suited to electricity generation on the order of 2,000 MW. Since IPPs supply less than 1 percent of Japan's electricity, it does not appear that they could obtain financing for LNG facilities on such a scale. Even if IPPs could persuade a gas or electric utility to sell them gas, it seems quite likely that they would be paying a premium over the electric utility's price of gas, putting them at a competitive disadvantage.

At present, electric utilities can readily pass on inefficiencies that may occur in gas procurement, shipping, and processing, as well as in building and operating their LNG facilities, in higher prices to electricity consumers. That is because consumers have few if any IPPs to turn to as alternative sources of power in any given service area. However, if technology for on-board gasification of LNG from import vessels develops, the economic scale for LNG imports by IPPs could become better suited to their needs. Alternatively, negotiated third-party access to LNG facilities as recommended by the Forum on Gas Market Reform and the Urban Heat Energy Subcommittee could make gas available to IPPs. In either case, an enhanced role for IPPs in the gas and electricity markets might bring sharper negotiation for gas price contracts, with resulting savings on gas costs passed on in more competitive prices to electricity users.

PRICE TRENDS

Since the gas and electric market reforms of 1999, wholesale gas suppliers have been free to set whatever prices they wish, taking account of their commodity and transport costs, with notification to METI. Wholesalers are defined as suppliers of at least 70,000 cubic metres of gas per annum to a gas utility. If METI finds that wholesale prices are inconsistent with fair trade, it may reject them.

In view of the wholesale pricing arrangements in place, price should in principle reflect wholesale competition among (mostly foreign) suppliers and efficiencies in managing LNG facilities and pipelines. However, price competition appears to have been hindered by widely-adopted formulas that link the price of LNG from Southeast Asia, Australia, Alaska and the Middle East to oil prices, specifically the "Japan Crude Cocktail" (JCC). Typically, the LNG price consists of a fixed base, plus a component that varies in constant ratio with the JCC price, plus an adjustment factor that varies with the degree that the JCC price falls above or below a "normal" band.[94]

Since most LNG contracts are for long-term supply according to this sort of formula, LNG prices in Japan have mainly reflected fluctuations in international oil prices rather than changes in

---

93 APEC Energy Working Group (2002), page 119. Of 229,150 MW of generating capacity, 60,280 MW was gas-fired.

94 *Middle East Economic Survey* (2001). While specific price formulas are generally confidential, the price formula negotiated between Qatar and Chubu Electric Power Company has been made public, according to which

LNG CIF Price = 0.1485 * JCC + 0.8675 +S

Where S is a price-band adjustment factor (or S-curve) defined as follows:

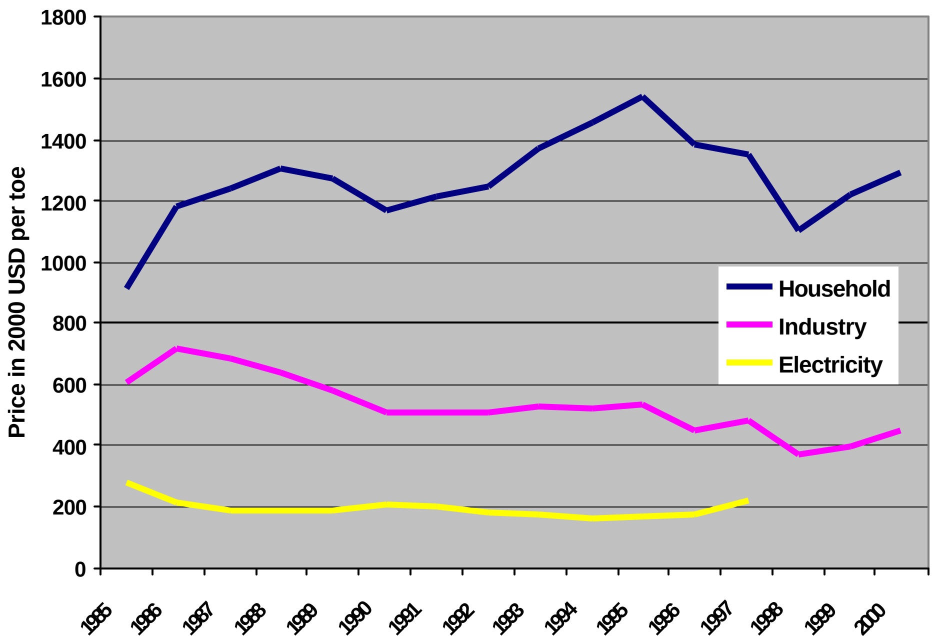
If JCC price ranges between 23.5 ($/barrel) and 29.0, S=(JCC-23.5)/(23.5 – 29.0);

If JCC price ranges between 16.5 ($/barrel) and 23.5, S=0;

If JCC price ranges between 11.0 ($/barrel) and 16.5, S=(16.5-JCC)/(16.5-11.0).

competitive conditions. Delivered gas prices to households and industry declined by roughly one-third between 1995 and 1998.[95] This may have been due in some part to the wholesale market reforms that were instituted in 1995, which allowed large industrial customers to shop around for the cheapest available gas on Japan's pipeline network.

Figure 44 Natural Gas Prices in Japan, 1985-2000



Source: International Energy Agency and US Departmentof Commerce

GAS MARKET REGULATIO N AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Since most of the economy's gas comes from abroad by sea, Japan is highly reliant on LNG terminals for gas transportation. There are 24 LNG receiving terminals in operation, and when planned new terminals and terminal expansions are completed, their import capacity will total 89 million tonnes of LNG per year, which is well in excess of current demand. By contrast, since over 60 percent of gas is used in powerplants that are located directly adjacent to LNG facilities, and since LNG supply costs do not vary enough to make it worth linking LNG facilities together, there is relatively little dependency on gas transmission pipelines, which total just 3,129 km in length.[96]

The gas distribution network in Japan is well developed in "densely inhabited districts" such as Kanto, Chubu, Kansai and Kyushu which serve the bulk of the economy's population. There are 28,400 km of medium-pressure and 204,844 km of low-pressure distribution lines. However, there remain significant areas with no gas service. There is no government policy for expansion of natural gas networks to such areas as it has been judged uneconomical. Decisions on expansion of local distribution grids are considered to be the responsibility of each gas distribution utility.

On the other hand, the government seeks improved interconnections between the high-pressure pipelines that have been separately developed by gas utilities, electric utilities, and others.

95 International En ergy Agency (1997) pages II.19-21, IEA (2002a) pages III.30-32. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

96 Miyamoto (2002), pages 132-3, 153, 172. METI (2003).

There are currently no links between the pipeline networks of the four major regional gas utilities. However, there is a private initiative to interconnect the pipelines of Tokyo Gas, Teikoku Oil, and Shizuoka Gas companies in the Tokai area. Economic and regulatory incentives to integrate pipelines into an economy-wide network were examined by the Urban Heat Energy Subcommittee, which recommended conferring eminent domain for construction of natural gas pipelines on non-gas utilities as well as gas utilities and allowing higher rates of return for trunkline construction.[97]

INFRASTRUCTURE INVESTMENT INCENTIVES

Investment incentives for expansion of the pipeline grid appear to be adequate. Gas utilities receive an overall rate of return (ROR) on capital rather than a rate of return on specific facilities. The regulated ROR is set to approximate the empirical weighted cost of debt and equity capital. The ROR is applied to a rate base that includes the value of all tangible assets, notably including both transmission and distribution pipelines and LNG receiving terminals. Normally, all assets are included in the rate base as long as they are operational; assets under construction are not.

When rate increases are requested by utilities, a system of "yardstick benchmarking" by the Ministry of Economy, Trade and Industry (METI) allows utilities to retain a portion of profits obtained through improvements in productive efficiency. Most expenses associated with facilities for gas service are subject to benchmarking, including depreciation, return on assets, rental costs and labour costs. However, taxes, fuel costs, and maintenance costs associated with safe network operation are excluded from benchmarking. Gas utilities are divided into sixteen different groups according to factors such as ownership (private or municipal), fuel procurement method, and region. Insofar as a utility's costs per unit of gas delivered are below the average costs for others in its group, a major portion of the cost differential may be retained by the firm.[98]

97 METI Gas Market Division (2003) and METI (2003).

98 Institute of Energy Economics, Japan (2002c).

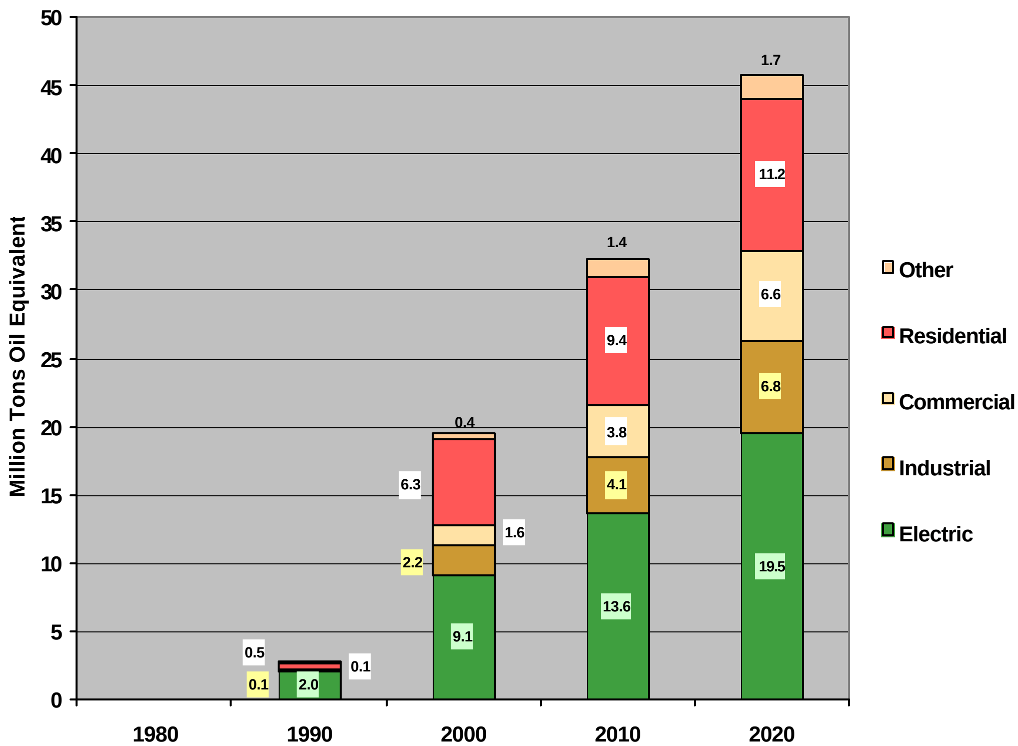
KOREA

GAS MARKET SETTING[99]

Korea relies on imports for all of its natural gas requirements.

- Gas supply and imports are projected to more than double from 19.4 Mtoe in 2000 to 45.7 Mtoe in 2020 due to steady demand growth averaging 5.2 percent per annum from 2000 to 2010 and 3.5 percent per annum from 2010 to 2020.

Figure 45 Evolution of Natural Gas Use in Korea, 1990-2020



Korea's natural gas use is well diversified, with about two-fifths of gas demand in the commercial and residential sectors, somewhat less than half of gas use occurring in the electric power sector, and most of the remainder accounted for by industry.

- Use of gas for power production is projected to grow at a steady pace, more than doubling from 9.1 Mtoe in 2000 to 19.5 Mtoe in 2020, but the power sector's share of gas use is projected to decline somewhat from 47 percent to 43 percent.
- Industrial gas use is projected to grow faster than power sector gas use, tripling from a small base of 2.2 Mtoe in 2000 to 6.8 Mtoe in 2020, so that its share of overall gas demand rises from 11 percent to 15 percent.

99 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

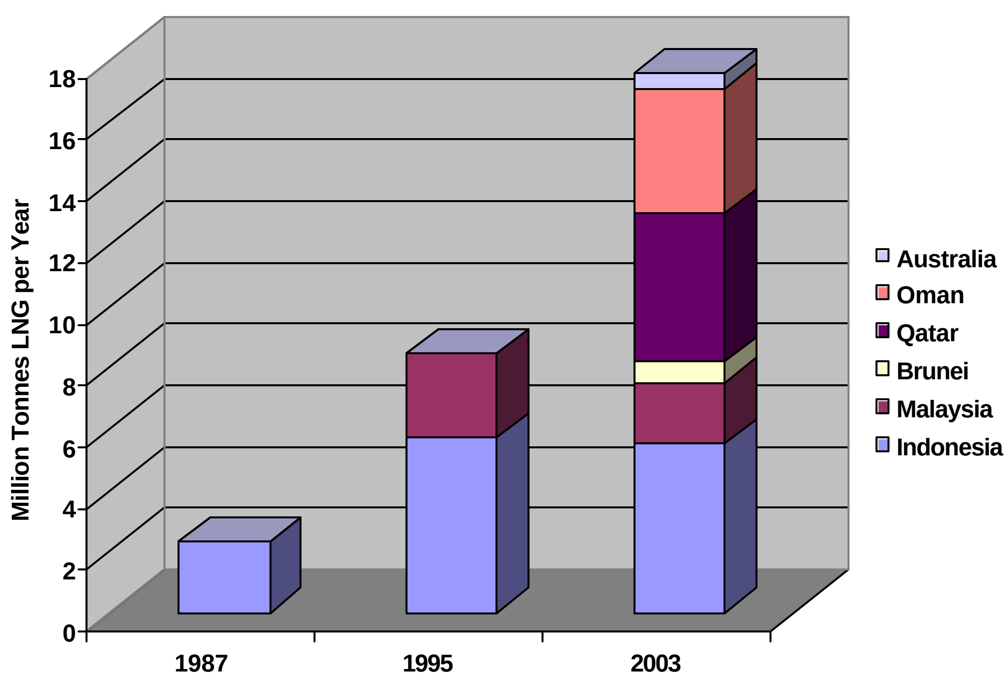
- The fastest growth in gas use is expected to occur in the commercial sector, with demand quadrupling from a small base of 1.6 Mtoe in 2000 to 6.6 Mtoe in 2020, increasing the sector's share of gas demand from 8 percent to 14 percent.
- Residential gas use is expected nearly to double from 6.3 Mtoe in 2000 to 11.2 Mtoe in 2020, but its share of overall gas demand is projected to decline sharply from 32 percent to 24 percent due to faster growth in other consuming sectors.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

All of Korea's gas is imported through LNG terminals. Gas is imported mainly from Indonesia (42 percent of imports in 2000), Qatar (22 percent), Malaysia (17 percent), Oman (11 percent) and Brunei Darussalam (5 percent). LNG imports began in 1986 under a 20-year take-or-pay contract with Indonesia for 2.3 million tons (3.0 Mtoe) per year. By 2000, Korea had seven take-or-pay contracts in place for the importation of 16.86 Mt (21.8 Mtoe) per year. The first of these contracts expires in 2007, while the most recent runs through 2024. To meet continued growth in gas demand, KOGAS began operating a third terminal at Tongyeong in 2002, plans to expand existing LNG facilities at Pyeongtaek and Incheon and plans to build a new LNG terminal at Pyeongtaek.[100]

Figure 46 Evolution of Korea's LNG Sources under Long-Term Contracts



Sources: IEA (2002e), IEEJ (2002b), Cedigaz (1999)

The entire gas transmission network, including all LNG receiving terminals and natural gas pipelines, is owned and operated by the Korea Gas Corporation (KOGAS). Prior to 1999, when 39 percent of its shares were sold to the public, KOGAS was entirely government-owned. The stated purpose of its privatisation was to reduce the need for public funds to finance investment in

100 IEA (2002e), page 96.

pipelines and LNG facilities, as well as to improve its efficiency with respect to cost and quality control, diversification of LNG sources, and negotiation of competitive contract terms from these sources. Distribution and sale of natural gas (from LNG provided by KOGAS) are accomplished by 28 private city gas companies, each of which has exclusive rights to operate in a defined urban area. But small amounts of gas have been sold directly by KOGAS to large industrial consumers near its facilities. In addition, four city gas companies distribute liquefied petroleum gas (LPG).[101]

PRINCIPAL PLAYERS IN KOREA'S GAS MARKET

External Producers from which Korea Imports Gas
Pertamina (Indonesia), Petronas (Malaysia), Brunei LNG, Qatar LNG, Oman LNG

Owner and Operator of LNG Terminals and Gas Transmission Pipelines in Korea
Korea Gas Corporation (KOGAS)

Owners and Operators of Gas Distribution Pipelines in Korea
Seoul: Daehan City Gas, Hanjin City Gas, Kangnam City Gas, Kukdong City Gas, Samchully, Seoul City Gas
Other Major Cities: Chungnam City Gas, Haeyang City Gas, Incheon City Gas, Kyongdong City Gas, Pusan City Gas, Taegu City Gas
Kangwon Province: Chambit Wonju City Gas, Kangwon City Gas
Chungbuk Province: Chongju City Gas
Chungnam Province: Chungbu City Gas, Hanseo City Gas (Hanbo Energy)
Kyongbuk Province: Kumi City Gas, Pohang City Gas, Seorabol City Gas
Kyongnam Province: Kyungnam Energy, ShinA City Gas
Cheonbuk Province: Cheonbuk City Gas, Iksan City Gas, Kunsan City Gas
Cheonnam Province: Chonnam City Gas, Daehwa City Gas, Mokpo City Gas

Sources: Korea Gas Corporation, Korea City Gas Association

UNBUNDLING AND THIRD PARTY ACCESS

Since all of Korea's gas is imported, the production of gas (by external suppliers) is obviously unbundled from gas transmission (by KOGAS). In addition, transmission of gas (by KOGAS) is unbundled from gas distribution. However, distribution and retail supply are bundled, as the 28 local city gas monopolies perform both functions.

There is currently almost no third-party access to gas transportation facilities in Korea. KOGAS controls all imports, so it provides access to transmission pipelines and LNG facilities only to itself. Local utilities in turn, provide access to distribution pipelines only for gas supplied by KOGAS. On the other hand, entities other than KOGAS have been allowed to import LNG for their own consumption since 2001 provided they own LNG storage facilities or obtain LNG storage rights from others. In order to take advantage of this opportunity, Posco and SK began building an LNG terminal at Gyangyang in 2002.

However, according to a reform plan announced in 1999, KOGAS was to provide open and non-discriminatory access to all of its LNG, pipeline and storage facilities as of 2003. All competing suppliers would be able to use these facilities to import gas and bring it to their large customers who can hook up directly to the gas transmission grid. To help ensure that KOGAS treats competing suppliers in a non-discriminatory fashion, it would be divested of most functions that do not relate to natural gas transportation. Three separate trading companies would be spun off to engage in import and wholesale trade, taking over existing supply purchase agreements

[101] Korea City Gas Association (2002).

(SPAs) from KOGAS and free to sign new SPAs going forward. Divisions that deal with maintenance, design and engineering of gas facilities, as well as investment in gas production and tugging of LNG carriers, would also be spun off. KOGAS would then retain its LNG, pipeline and storage facilities but no supply function.[102] However, details of the reform plan were still under discussion in 2003. As an alternative to spinning off KOGAS import and wholesale trade functions, the government is considering allowing the entry of competing private companies into the market for these functions.[103]

At a later stage, the open access regime is to be extended to gas distribution. The regional distribution monopolies are to be unbundled into separate distribution and retail supply companies. Competing suppliers would then be able to use the distribution grid on non-discriminatory terms to bring gas to small residential and commercial customers. This would be a significant step since small consumers constitute two-fifths of Korea's gas market.

MARKET MODEL AND COMPETITION

At present, the gas market in Korea would seem to fit most closely the wholesale competition model, although the extent of competition is rather limited. KOGAS purchases gas from several competing foreign producers and does so from the least cost bidders; in this sense, there is wholesale competition. But all of the foreign producers operate as vertically integrated monopolies in their home markets. And since all major import contracts are on a long-term, take-or-pay basis, there is very limited scope for competition from other producers. While there is some potential retail competition in the sense that large gas consumers are allowed to import LNG for their own use instead of buying it from KOGAS, no consumers had done so as of the end of 2002.

Looking to the future, however, Korea may better fit the customer choice model. As gas demand continues to grow, the market should accommodate imports from additional producers. Open access to LNG terminals, storage facilities and high-pressure pipelines, as envisioned in the gas industry reform plan, would allow effective competition for large industrial customers and electric power generators. Later on, open access to distribution pipelines would allow effective competition for small customers as well.

Korea's gas and electricity markets are at present vertically integrated to a significant degree, not only because gas is provided to all power producers through a single buyer, but also because gas accounts for a sizeable share of power production and because long-term gas supply contracts are in place with a particular power producer. Natural gas accounted for 11 percent of electricity generation and 26 percent of electric generating capacity in Korea in 2000. A large share of gas use is by independent power producers (IPPs), which accounted for 14 percent of generating capacity. KOGAS has no financial interest in the electricity sector and should thus be willing, in principle, to supply gas to all competing electricity generators on a non-discriminatory basis. However, until 2006, the Korea Electric Power Company (KEPCO) is obliged to purchase a certain amount of gas under take-or-pay arrangements with KOGAS. Although the take-or-pay amount is negotiable, the arrangement apparently requires a greater use of natural gas for power production than would occur in a strict cost-minimising environment. Thus, it may put KEPCO at a competitive disadvantage while also restricting the available supply of gas to other power producers.[104]

Even after KEPCO's take-or-pay obligations expire, significant integration will remain between Korea's gas and power markets as long as KOGAS remains the dominant gas supplier. If all power producers are obliged to obtain gas from the same source, their gas costs are likely to be similar, so the effective scope for competition among their gas-fired power plants will be limited to capital and operating costs. With such a large share of generating capacity designed to use gas, the flexibility of power producers to shift to other fuels in response to higher prices will also be limited. Thus,

102 IEA (2002e), pages 101-103. IEEJ (2002a), pages 474-476.

103 Ministry of Commerce, Industry and Energy (2003).

104 IEA (2002e), pages 55 and 57. IPPs had 6,708 MW of generating capacity in 2000, or 14 percent of Korea's 48,451 MW of generating capacity, of which 2,872 MW was gas-fired, 23 percent of Korea's 12,698 MW of gas-fired capacity.

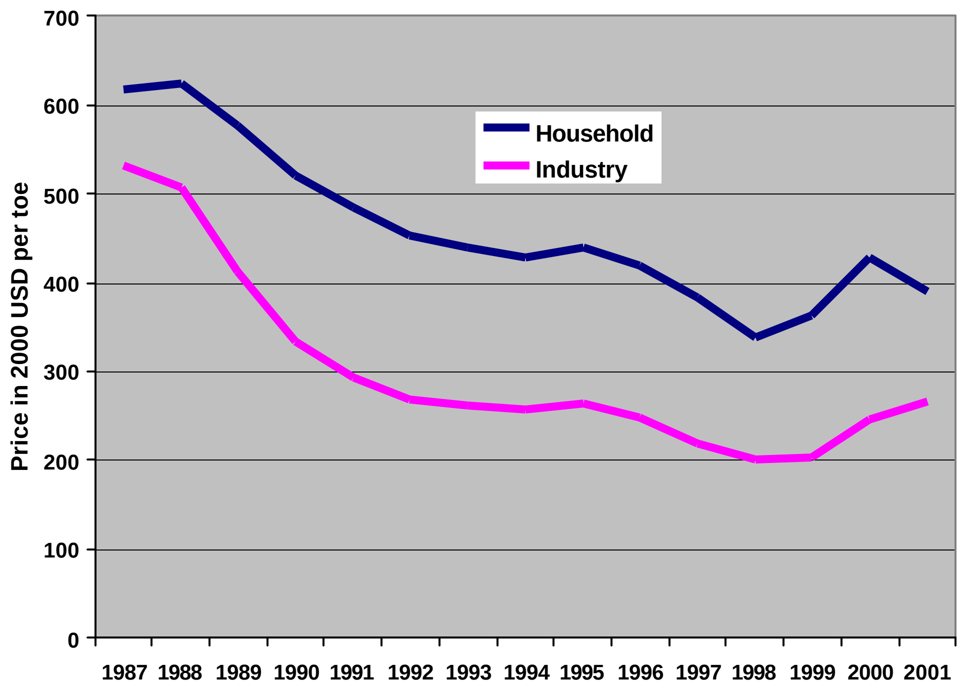
KOGAS has considerable market power to pass on inefficiencies that may occur in gas procurement, shipping, and processing, as well as in construction and operation of LNG facilities and pipelines, in higher gas prices to power producers.

Over the longer term, as competing suppliers appear in the gas market and IPPs play a growing role in the power market, the integration of gas and electricity markets should begin to dissipate. Pursuant to electricity industry restructuring plans that have passed the National Assembly, open access is to be provided to the electric transmission network after 2004 and to electric distribution grids after 2009. Thus there will soon be wholesale competition among electricity generators for sales to power distribution companies, and there will later be retail competition among generators for sales to final customers. So if gas market reform plans are implemented, there should be retail competition among gas producers for the business of electricity generators, and resulting savings in gas costs should be passed to both producers and consumers of electricity.

PRICE TRENDS

Natural gas prices in Korea declined steadily in the late 1980s and most of the 1990s, before rebounding in the late 1990s. For industrial customers, the real price in 2000 US$ declined by 26 percent from US$333 per tonne of oil equivalent in 1990 to US$246 per toe in 2000. The real price for households dropped by 18 percent from US$521 to US$427 per toe during the decade.[105]

Figure 47 Natural Gas Prices in Korea, 1987-2001



Sources: Korea Energy Economics Institute, IEA, IMF, US Department of Commerce

These price trends would appear to be due mainly to trends in international LNG prices according to the terms of long-term import contracts that KOGAS has negotiated. The average commodity price for gas imported into Korea at the start of 2000 was about 288 won per cubic metre, exclusive of handling charges, tariffs, excise taxes and surcharges. Including such additional

105 Korea Energy Economics Institute (2002), page 65. Nominal prices in US$ calculated by dividing prices in won per cubic metre by a heat rate of 10,500 kcal per cubic metre, by prevailing exchange rates of won per US$ from IEA (2002b) page 338 and IMF (2002) page 629, and by 10 million kcal per toe. Real prices in US$ calculated by dividing nominal prices in US$ by implicit GDP deflators from US Department of Commerce.

items, the commodity price was about 326 won for electricity producers and 335 won for others. By contrast, the average transportation price for gas in Korea at the end of 2001 was just 78 won per cubic metre, including LNG terminal costs, pipeline transmission costs to the city gate and local distribution costs. Thus, direct and indirect LNG commodity costs account for roughly four-fifths of the delivered price of natural gas on average. It follows that changes in the costs of imported LNG dominate fluctuations in overall delivered gas prices.[106]

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Korea's gas transportation infrastructure appears to be keeping pace with rapidly growing demand. LNG storage facilities at the end of 2002 included 26 tanks with a total capacity of 2.96 million cubic metres (Mcm). There are plans to substantially more than double LNG storage facilities over the next decade or so to include a total of 55 tanks with a capacity of 7.38 Mcm.[107]

The gas distribution network in Korea is well developed, and there are no plans to expand it further. The service areas of the city gas companies cover almost all the economy's territory except for a few sparsely populated rural areas to which pipeline has not been laid.

INFRASTRUCTURE INVESTMENT INCENTIVES

Incentives for investment in new gas transmission infrastructure appear to be quite adequate. In its rates to gas users, KOGAS is allowed to recover all costs of investment in pipelines and LNG terminals, including borrowing costs, plus a 2 percent premium. At present, only KOGAS can invest in gas transmission infrastructure and collect regulated rates for its use. For purposes of ratemaking, gas transmission costs are divided into five functional categories: unloading, storage, regasification and injection, pipelines, and valve stations. Costs in each category are then allocated between power generating companies and city gas supply companies.[108]

Investment incentives for enhancement of gas distribution grids also appear to be sufficient. The distribution costs of city gas companies are typically recovered in rates through a cost-plus methodology in which a market-based rate of return is allowed on equity. Rates for each city gas company must be approved by the local government that has jurisdiction in its area.[109]

106 APERC (2002c), pages 30-31. Transportation charges vary by time and type of customer. They ranged from 26 to 46 won per cubic metre for electricity generators at the start of 2000, depending upon the season. They were 33 won for industrial customers, 46 won for commercial customers, and 107 won for residential heating and 134 won for residential cooling at the end of 2001.

107 Ministry of Commerce, Industry and Energy (2003).

108 *Ibid.* APERC (2001a), page 66.

109 APERC (2001a), pages 52-3.

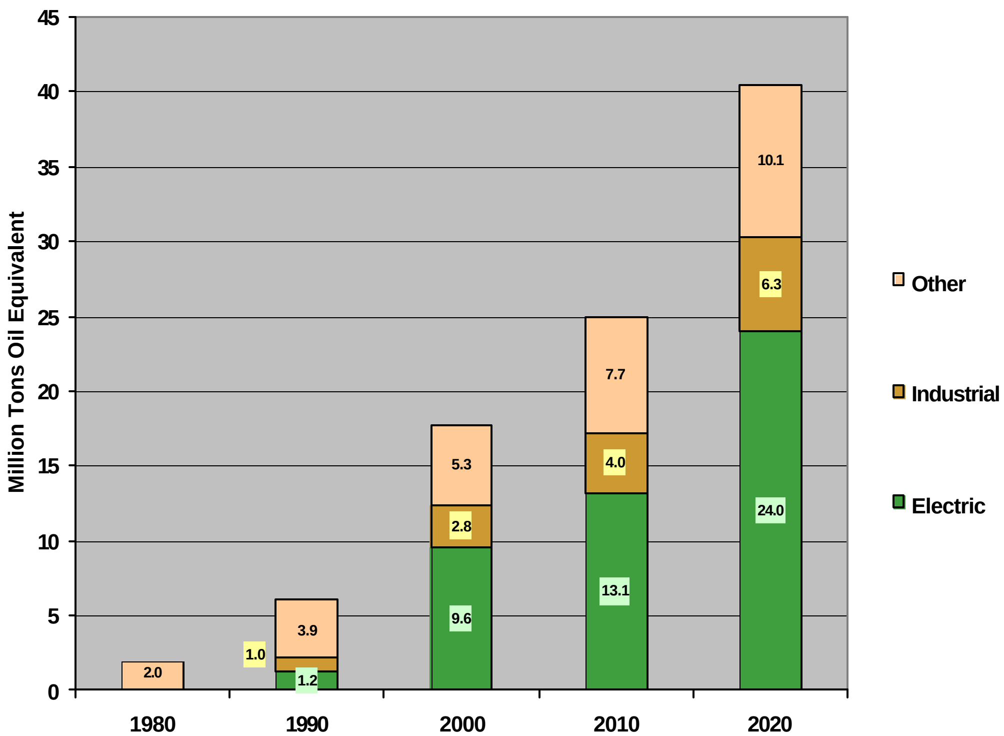
MALAYSIA

GAS MARKET SETTING[110]

Malaysia is a major gas producer and exporter, with gas supplied to the economy almost entirely from domestic production.

- Gas production is projected nearly to double from 34.2 Mtoe in 2000 to 65.0 Mtoe in 2020, but net exports as a share of production are projected to decline markedly from 48 percent to 38 percent due to growth in domestic demand and imports.
- Primary supply of gas to the domestic economy is projected to more than double from 17.7 Mtoe in 2000 to 40.4 Mtoe in 2020, with average annual growth of 3.5 percent in the decade from 2000 to 2010 and 5.0 percent from 2010 to 2020.

Figure 48 Evolution of Natural Gas Use in Malaysia, 1980-2020



Very nearly all of Malaysia's natural gas use is devoted to energy transformation and industry. About five-sixths of the economy's gas is used in energy transformation. Of this portion, two-thirds goes to electricity generation and one-third to gas production, with the relative importance of electricity generation expected to grow over time. Almost all the remaining gas use is by industry.

- Use of gas for electric power generation is projected to substantially more than double from 9.6 Mtoe in 2000 to 24.0 Mtoe in 2020, so that the power sector's share of overall gas demand increases from 54 percent to 59 percent.

110 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Industrial use of gas is also expected to more than double from 2.8 Mtoe in 2000 to 6.3 Mtoe in 2020, while its market share remains just below 16 percent.
- "Other" gas use, primarily for gas production, is projected nearly to double from 5.3 Mtoe in 2000 to 10.1 Mtoe in 2020, while its share of the gas market falls from 30 percent to 25 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Production and transmission of gas in Malaysia are undertaken by the same government-owned company, Petronas. The head office of Petronas carries out exploration, development and production activities. A wholly-owned subsidiary, Petronas Carigali Sdn Bhd (PCSB), has production-sharing contracts with several international oil and gas companies. Another subsidiary, Petronas Gas Bhd (PGB), is responsible for the trans-peninsular pipeline that crosses Malaysia, as well as for gas processing. PGB was listed on the Kuala Lumpur stock exchange in 1995, but Petronas owns 75 percent of its shares. A monopoly distributor, Gas Malaysia Sdn Bhd (GMSB), obtains gas produced by Petronas through pipelines owned and controlled by Petronas. Gas Malaysia is also partially owned by Petronas, which has a 20 percent share of its assets.[111]

PRINCIPAL PLAYERS IN MALAYSIA'S GAS MARKET

Gas Producers in Malaysia

Petronas Carigali Sdn Bhd (in production sharing contracts with
Esso Production Malaysia (EPMI), Sarawak Shell Berhad (SSB),
Sabah Shell Petroleum Company (SSPC), and Occidental (Malaysia) Ltd)

Owners and Operators of Gas Transmission Pipelines in Malaysia

Petronas Gas Bhd (PGB)

Owners and Operators of Gas Distribution Pipelines in Malaysia

Gas Malaysia Sdn Bhd (GMSB)(joint venture between Petronas (20 percent share),
MMC-Shahpadu (55 percent share) and Tokyo- Gas – Mitsui (25 percent share))

Sources: APERC, Gas Malaysia

Traditionally, there has been little economic regulation of Malaysia's gas industry since it has been directly controlled by the state. However, an Independent Energy Commission came into being in May 2001, pursuant to the Energy Commission Act of 2000, with responsibility to improve economic and safety regulation in the gas and electricity industries.

UNBUNDLING AND THIRD PARTY ACCESS

The functions of Malaysia's gas market are not unbundled to any significant extent. Petronas controls all gas production and transmission. Gas Malaysia controls all distribution. Since there are no competing producers, there is no third party access to the transmission or distribution grids.

111 APERC (2000c), pages 53-54. IEEJ (2002a), page 121. Gas Malaysia (2003). Other partners in Gas Malaysia are MMC-Shahpadu Holdings, with a 55 percent stake, and Tokyo Gas – Mitsui Holdings with 25 percent share.

MARKET MODEL AND COMPETITION

The Malaysian gas market closely adheres to the vertically integrated monopoly model. Petronas has a legal monopoly on gas production and transmission. Gas Malaysia has a legal monopoly on gas distribution, and Petronas supplies all the gas that Gas Malaysia sells.

While Malaysia has started to import some gas from Indonesia and is expected to import greater amounts over time, there is little likelihood that this will introduce a significant measure of competition to the economy's gas market. All of the imports anticipated to date will be provided through long-term contracts between Petronas and Indonesia's monopoly gas producer, Pertamina, over pipelines jointly constructed by the two companies in order to fulfil the contracts. Over the longer term, as Malaysian gas needs grow, it is conceivable that Petronas could wind up buying gas from other suppliers as well, including independent gas producers which are to be allowed to compete with Pertamina in Indonesia. But Malaysia is expected to remain a major net gas exporter for decades, so the overall role of foreign gas in the domestic market is likely to remain quite limited. More fundamentally, Petronas Gas would presumably transport the gas produced by its affiliate, Petronas Carigali, whenever it is available, even if foreign gas is available at lower cost.

Furthermore, Malaysia's gas market is vertically integrated with its electricity market to a very great extent. More than three-quarters of the economy's electricity generation in 1999 came from gas, and more than four-fifths of its gas consumption goes to the production of electricity. Of incremental capacity planned through 2005, more than half is gas-fired. The state-owned electric utility, Tenaga Nasional Berhad (TNB), faces competition from independent power producers (IPPs), which generated 43 percent of the economy's electricity in 2000, mostly from gas. But TNB retains a monopoly on transmission, distribution and retailing in Peninsular Malaysia.[112] Since all gas-fired power plants must buy gas from the same producer, their generating costs will be changed by similar amounts if Petronas raises or lowers its prices. Moreover, with the large share of gas-fired generating capacity, power producers have limited flexibility to shift to other fuels.

Thus, as the sole supplier of gas to the economy, Petronas has very substantial market power to pass on the costs of inefficiencies that might arise in gas production and processing, as well as in the operation of pipelines, in higher gas prices to power producers. Alternatively, since Petronas is owned by the state, the government may decide to subsidise gas prices to power producers. As the sole supplier of electricity to final customers in Peninsular Malaysia, TNB has the market power to pass on increased costs of gas and power production in rates or to decline to fully pass on reduced costs of gas and power production in rates. But since TNB, like Petronas, is state-owned, the government may take political as well as economic factors into account in setting electricity rates.

PRICE TRENDS

In early 2003, Gas Malaysia slashed gas prices by more than half for its largest customers. There are five tariff categories, corresponding to different customer sizes and types. The tariff for large manufacturers was reduced from RM1.06 to RM0.49 per cubic metre of gas, or from RM28.5 to RM13.2 per million Btu, with retroactive effect from October 2002 through December 2005. The price cut was possible because Gas Malaysia receives gas from Petronas at a fixed price of RM9.40 per MBtu, which was about 20 percent below the market price in early 2003. Petronas has also been providing gas to electric power producers at a fixed price of RM6.40 per MBtu since 1997, which was roughly 45 percent below the market price in early 2003.[113]

---

112 APERC (2002b), page 66. IEEJ (2002a), pages 135-42. Of 8,800 MW of new generating capacity planned for 2001-2005 in Peninsular Malaysia, 6,000 MW was gas fired, of which 1,830 MW was being built by TNP and 3,170 MW by IPPs. Of the 5,076 MW of capacity owned and operated by IPPs in 2000, 4,831 MW or 95 percent was gas-fired.

113 Gas Malaysia (2003). "Government Slashes Natural Gas Prices by Half" (article by Kamarul Yunus, 19 March 2003). Conversions from prices per cubic metre to prices per MBtu assume conversion factors from IEA (2002a) of 39.249 megajoules per cubic metre of gas produced in Malaysia and 947.8 MBtu per million megajoules of gas in general.

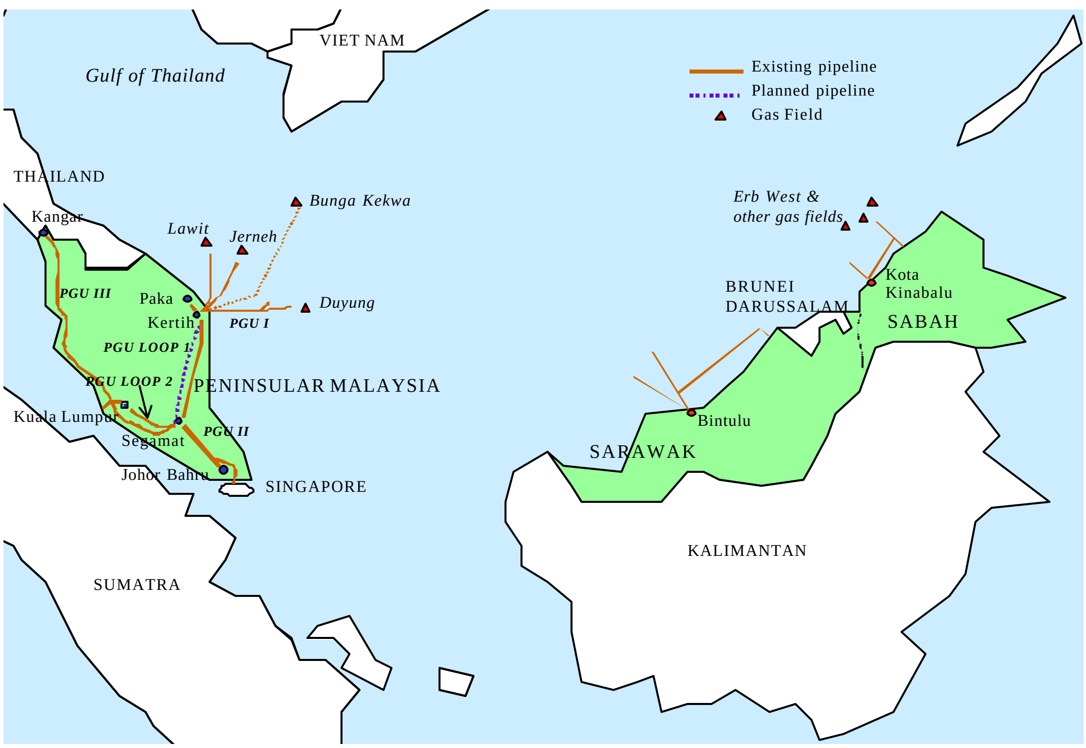
GAS MARKET REGULATIO N AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Petronas Gas had roughly 2,000 km of transmission pipeline with 2,000 million cubic feet (57 million cubic metres) per day of capacity as of the end of 2002.[114] The largest component of the transmission grid is the Malaysian Peninsular Gas Utilisation (PGU) project which by 1998 had 1,420 km of pipeline moving 1,163 Mcf (33 Mcm) of gas per day. The PGU grid moves mostly indigenous gas but also some gas imported from Indonesia. The transmission grid is less developed in the regions of Sabah and Sarawak, which are adjacent to Brunei Darussalam and Indonesia.[115]

A vital portion of Malaysia's gas transportation infrastructure consists of three large LNG terminals for exportation of gas to Japan, Korea and Chinese Taipei, mostly under long-term contracts. The Satu, Dua and Tiga LNG terminals have annual export capacities of 8.1 Mt, 7.8 Mt and 7.6 Mt, respectively, providing a total export capacity of 23.5 Mt per annum. Each of the LNG terminals is owned by a consortium of Petronas, Shell, Mitsubishi, and the Sarawak state government, with Petronas holding controlling interests of 65, 60 and 60 percent respectively.[116]

Figure 49 Existing and Planned Gas Pipeline Infrastructure in Malaysia



Source: APERC (2000c)

Malaysia anticipates expansion of its high-pressure gas transmission grid to accommodate growth in gas production, export and use. Much of the expansion will be associated with

[114] Prime Minister's Department (2003).

[115] IEEJ (2002a), pages 124-25, 131. The PGU grid is linked by a 97 km pipeline to Indonesia's Duyon gas field from which Pertamina is providing 100 Mcf per day as of 2002, ramping up to 250 Mcfd by 2007. It is also to be linked by a 500 km pipeline with Indonesia's Asamara gas field, from which Pertamina is to provide 300 Mcfd starting in 2004.

[116] IEEJ (2002a), pages 132-34. Wybrew-Bond (2002), page 297.

development of offshore projects near the Malaysian Peninsula, production from which is expected roughly to double within the next few years to 1.3 billion cubic feet (37 Mcm) of gas per day.[117]

Gas Malaysia's distribution grid, which included some 790 km of pipelines in 2002, is largely concentrated in the Klang Valley but spans most of the coastline of the Malaysian peninsula. Pipeline extensions to new areas are market-driven, with pipeline built only where economically justified by potential demand. While virtually all gas use is related to energy transformation and industry, demand might someday develop in the residential and commercial sectors through installation of gas-fuelled air conditioners and combined heat and power units in buildings.[118]

INFRASTRUCTURE INVESTMENT INCENTIVES

Malaysia's incentives for investment in transmission infrastructure for delivering gas to export markets appear to be adequate. Since prices for exported gas are market-determined, facilities for the production and transmission of such gas will presumably be built whenever economical.

But it would seem that at least in recent years, some of Malaysia's domestic gas prices have been below those that would prevail in a normally functioning marketplace. This can be seen by comparing market-determined prices for gas exports with regulated prices for domestic gas use. Gas prices for the state electricity producer, TNB, have been held below export gas prices since 1997. Gas prices for industrial, commercial and residential customers will apparently be held below export gas prices for at least the period from late 2002 through the end of 2005.

Under normal circumstances, the relatively low domestic gas prices would be expected to make investment in gas pipelines for serving domestic customers substantially less attractive than investment in pipelines and LNG facilities for serving export markets. Since much of the basic distribution infrastructure is now in place on the Malaysian peninsula, and since decisions on expansion of transmission infrastructure can be made by the government for implementation by Petronas, the impact of such distorted incentives on gas supply may be quite limited. Nonetheless, the maintenance of artificially low domestic gas prices would seem to encourage inefficient use of gas by consumers and also to have a substantial adverse impact on state revenues.

117 *Ibid*., page 128. Deliveries of 400 Mcfd began from the Resak gas field in early 2000, while deliveries of 260 Mcfd began from the Angsi gas field in early 2002, summing to overall deliveries from offshore of 660 Mcfd.

118 Gas Malaysia (2003). Kim (1994), pages 120-21. The distribution grid has expanded substantially. In the early 1990s, it served just twelve industrial communities: Kuantan, Kemaman, Shah Alam, Seremban, Pasir Gudang, Kelang, Kluang, Petaling Jaya, Kuala Lumpur, Bangi, Salak Tinggi and Gebeng. It now serves quite a few additional towns such as Kamunting, Sepang, Puchong, Banting, Putrajaya, Senawang, Cyberjaya, Jeram, Bukit Kemuning, Senai and Alor Gajah.

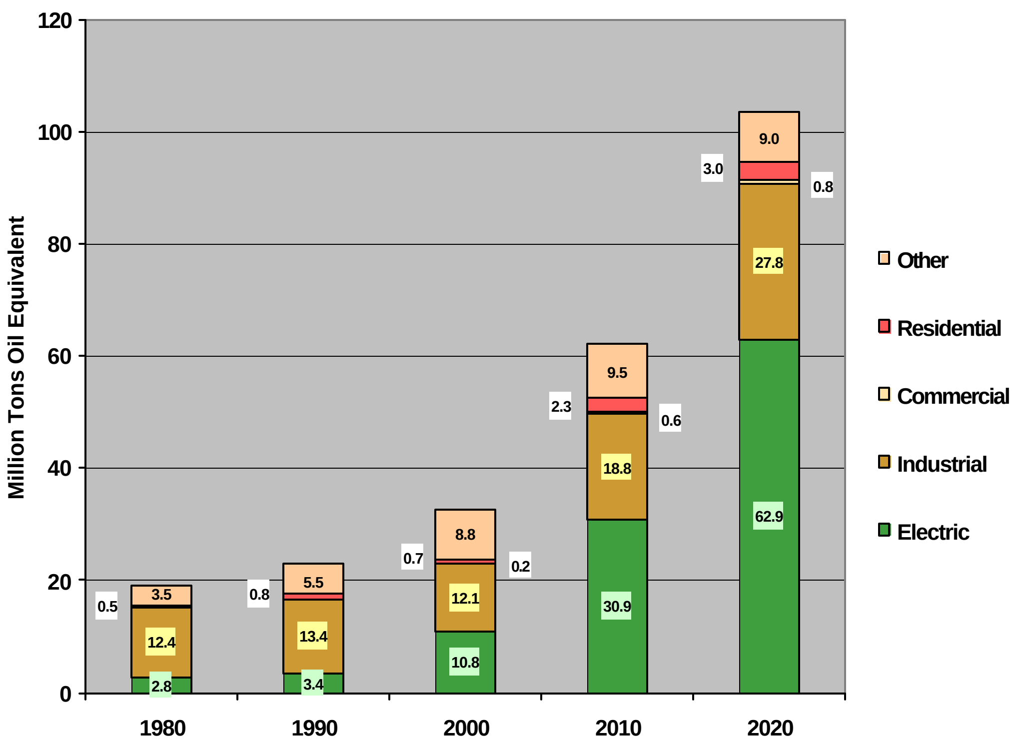
MEXICO

GAS MARKET SETTING[119]

Mexico is a large gas producer but an even larger gas consumer, with production not entirely sufficient to meet domestic demand.

- Gas production is projected to grow about two-and-a-half-fold from 31.2 Mtoe in 2000 to 77.7 Mtoe in 2020, but the gap between demand and production is projected to widen from 4 percent to 33 percent of production over the period.
- Net imports of gas, mostly from two-way gas trade with the United States, are projected to increase roughly from 1 Mtoe in 2000 to 26 Mtoe in 2020.
- Primary supply of gas to the domestic economy is projected to more than triple from about 33 Mtoe in 2000 to 103 Mtoe in 2020, with rapid growth averaging 6.6 percent yearly from 2000 to 2010 and 5.2 percent yearly from 2010 to 2020.

Figure 50 Evolution of Natural Gas Use in Mexico, 1980-2020



Almost all of Mexico's natural gas use is devoted to energy transformation and industry. Roughly three-fifths of the economy's gas is used in energy transformation. Of this portion, somewhat less than half is taken up by oil production while more than half goes to electricity generation, the share of which is expected to grow over time. Most remaining gas use is accounted for by industry, with small amounts also occurring in the residential and commercial sectors.

119 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Use of gas for electric power generation is projected to grow nearly six-fold from 10.8 Mtoe in 2000 to 62.9 Mtoe in 2000, so that the power sector's share of overall gas demand nearly doubles from 33 percent to 61 percent.
- Industrial use of gas is also expected to grow substantially, more than doubling from 12.1 Mtoe in 2000 to 27.8 Mtoe in 2020, but its market share is projected to drop from 37 percent to 27 percent due to the much more rapid growth in gas use for power production.
- "Other" gas use, primarily for oil production, is expected to be stable but to diminish in relative importance as the economy diversifies, so that its share of the gas market falls by a factor of three from 27 percent in 2000 to 9 percent in 2020.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKE T PLAYERS

Mexico has only a single domestic gas producer, the state-owned Petróleos Mexicanos (PEMEX). A small but growing amount of gas is imported from competing foreign producers.

PRINCIPAL PLAYERS IN MEXICO'S GAS MARKET

Gas Producers in Mexico
Petróleos Mexicanos – PEMEX Exploración y Producción

Owners and Operators of Gas Transmission Pipelines in Mexico
Petróleos Mexicanos – PEMEX Gas y Petroquímica Básica,
Kinder Morgan, Gas Natural México, Gasoductos de Chihuahua, Igasamex Bajío,
Energía Mayakán, Tejas Gas de Toluca, FINSA Energéticos,
Transportadora de Gas Zapata, Gasoductos del Bajío,
Transportadora de Gas Natural de Baja California, Ductos de Nogales,
Gasoducto de Tamaulipas, Gasoducto del Río

Owners and Operators of Gas Distribution Pipelines in Mexico
Gas Natural México, Tractebel, Gaz de France, Sempra Energy,
Compañía Nacional de Gas, Gas Natural del Noroeste, Compañía Mexicana de Gas,
Gas Natural de Juárez, Distribuidora de Gas de Occidente

Retail Gas Marketers in Mexico
PEMEX Gas y Petroquímica Básica, CH4 Energía, Energas de México,
Gas Natural Tres Naciones, Transnatural

Source: Secretaría de Energía, Comisión Reguladora de Energía (CRE)

Most of the transmission network is owned and operated by PEMEX, which held a monopoly on transmission service until 1995. As of October 2002, the Energy Regulatory Commission (Comisión Reguladora de Energía, CRE) had granted 100 operative permits for gas transmission over 11,481 km of high-pressure pipeline, with a capacity of 15,255 million cubic feet per day (Mcfd). Of these, 16 permits were for 10,864 km of pipelines operated under an open access regime, with 10,765 Mcfd or 71 percent of the total transmission capacity, and 84 permits were for 617 km of short pipelines operated by industrial firms for their own use, with 4,490 Mcfd or 29 percent of transmission capacity. Of the portion of the pipeline network under the open access regime, PEMEX accounted for 2 of the 16 permits, 9,043 km of pipeline or 83 percent of the network by length, and 5,217 Mcfd or 48 percent of the network by capacity.

With respect to natural gas distribution, 21 permits granted by CRE were in effect as of December 2002 for the operation of 27,723 km of pipeline with 1,511 Mcfd of capacity. Each distribution permit represents a five-year commitment. The three largest distribution companies are Gas Natural México, with 7 permits and 450 Mcfd or 30 percent of the distribution capacity commitments; Tractebel, with 3 permits and 387 Mcfd or 26 percent; and Gaz de France, with 3 permits and 384 Mcfd or 25 percent. Sempra Energy, with 3 permits and 117 Mcfd, and Compañía Mexicana de Gas, with 115 Mcfd, each hold 8 percent of the distribution capacity commitments. The rest of the distribution permits are held by 4 firms with 3 percent of the capacity commitments. There were also several gas retail companies competing to supply gas to 2.3 million gas customers.[120]

UNBUNDLING AND THIRD PARTY ACCESS

Production and transmission of gas in Mexico are only partially unbundled from each other. The monopoly producer, PEMEX, controls nearly three-quarters of the high-pressure pipeline transmission capacity that is subject to open access as a common carrier. There is accounting separation between the production and transmission arms of PEMEX, but there are no information firewalls between the two, so there could be opportunities for discrimination on the PEMEX pipeline network in favour of PEMEX production. However, PEMEX controls only about half of the overall transmission capacity if pipelines operated by large industrial firms and electricity generators for their own use are taken into account. In addition, the small but rapidly growing share of production obtained from imports is also clearly unbundled from transmission.

By contrast, the transmission and distribution of gas in Mexico are substantially unbundled. There are 12 different gas transmission companies and 10 different gas distribution companies. Only a single company, Compañía Mexicana de Gas, performs both transmission and distribution. In any given area, the same party can be awarded both transmission and distribution permits only if efficiency would be raised, costs would be lowered, and no transportation infrastructure is in place.

In legal terms, there has been regulated third party access to both transmission and distribution of gas in Mexico since 1995. Access to transportation services must be provided with similar terms to similar clients under similar conditions. Holders of permits to operate a transmission pipeline or distribution grid are only allowed to refuse access when they do not have available capacity or when interconnection is not technically feasible. Moreover, permit holders are required to expand their systems as long as they can recover expansion costs through fees, so they may not artificially inhibit entry by competitors by restricting the capacity of their networks over the longer term.[121]

Gas transmission pipelines and distribution grids are regulated by the Comisión Reguladora de Energía (CRE). The CRE grants permits for transmission and distribution pipelines, monitors the open access regime in gas transmission and distribution, and tries to ensure that there is no cross-subsidisation among market functions. It may also set maximum prices for initial sales of gas commodity to limit the market power of PEMEX as the sole gas producer in the economy.[122]

MARKET MODEL AND COMPETITION

The Mexican gas market would seem to conform most closely to the vertically integrated monopoly model. While the integrated monopoly that PEMEX possessed was legally abolished in 1995, PEMEX remains the sole domestic producer of gas and also retains control over the bulk of the high-pressure gas transmission network. While PEMEX faces competition from gas imports, almost all the gas moving through PEMEX pipelines is from PEMEX gas fields – both because domestic production still provides all but a few percent of total gas supply and because PEMEX may be able to discriminate in favour of its own production where imports are available.

On the other hand, if the share of imports in gas consumption grows over the next two decades, the dominance of PEMEX will be eroded. More effective competition may then develop

120 Secretaría de Energía (2001, 2002a). Comisión Reguladora de Energía (2001a).

121 Comisión Reguladora de Energía (1996).

122 *Ibid.*

at both wholesale and retail levels. Moreover, on the retail side, due to provisions for "contractual bridging" through competing retailers and "physical bridging" through direct links to the transmission grid, large users have an increasing say in who supplies their gas.

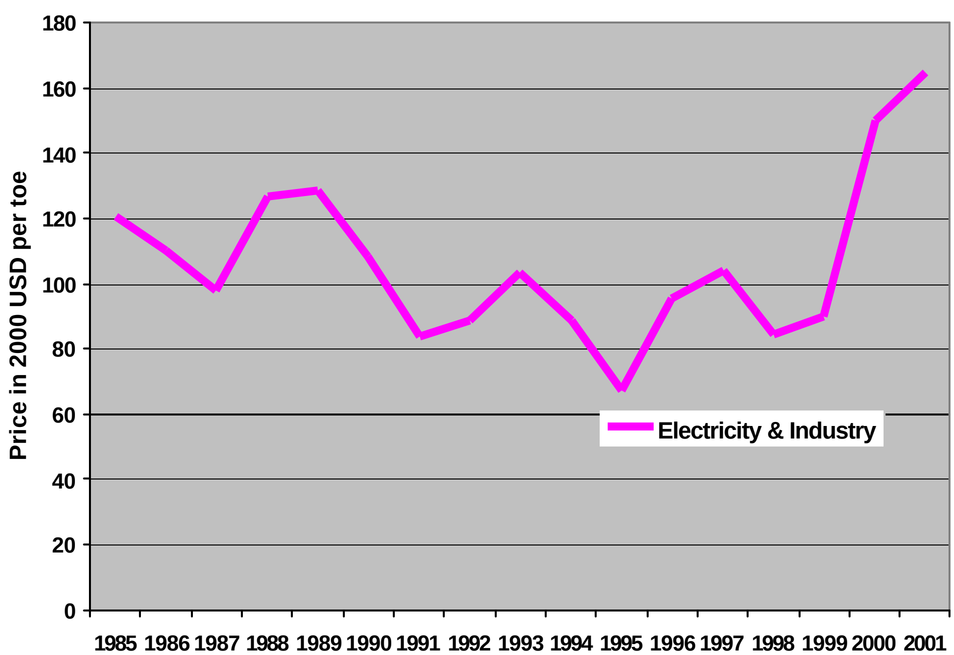
Mexico's gas and electricity markets are vertically integrated to a substantial degree. Roughly 16 percent of the economy's power was generated from gas in 2001, and the share is expected to grow rapidly since the government projects that three-eighths to three-quarters of the generating capacity built over the next 20 years will be gas-fired. A state-owned utility, Comisión Federal de Electricidad (CFE), generated 97 percent of Mexico's electricity and owned 96 percent of its electric transmission grid in 2001. Another state-owned utility, Luz y Fuerza del Centro (LFC), owned the rest of the electric transmission grid and generated a small amount of electricity for sale over its portion of the grid. Privately-owned independent power producers (IPPs) generate very small amounts of electricity which must usually be sent to customers over CFE's transmission lines.[123]

With a large and growing share of gas-fired capacity, the flexibility of electricity generators to switch to other fuels is increasingly limited. Yet they must buy almost all of their gas from PEMEX, which still supplies 95 percent of all gas used. Thus, the scope for competition between CFE and other power producers is largely restricted to capital and non-fuel operating costs. Growing reliance on gas-fired generation also means that PEMEX can pass on inefficiencies in gas production and transportation in higher gas prices to power producers without fear that demand for gas will be substantially reduced. This is all the more true since CFE faces limited competition in most areas and so can pass on increased gas prices to most electricity consumers in higher rates.

PRICE TRENDS

For the most part, price trends in Mexico have followed those of reference prices elsewhere in North America. This stems from the fact that the regulated gas prices charged by PEMEX are linked by formula to a basket of gas prices in southern Texas.[124]

Figure 51 Natural Gas Prices in Mexico, 1985-2001



Source: International Energy Agency and US Department of Commerce

123 Secretaría de Energía (2002b).

124 Secretaría de Energía (2002a), pages 27 and 33.

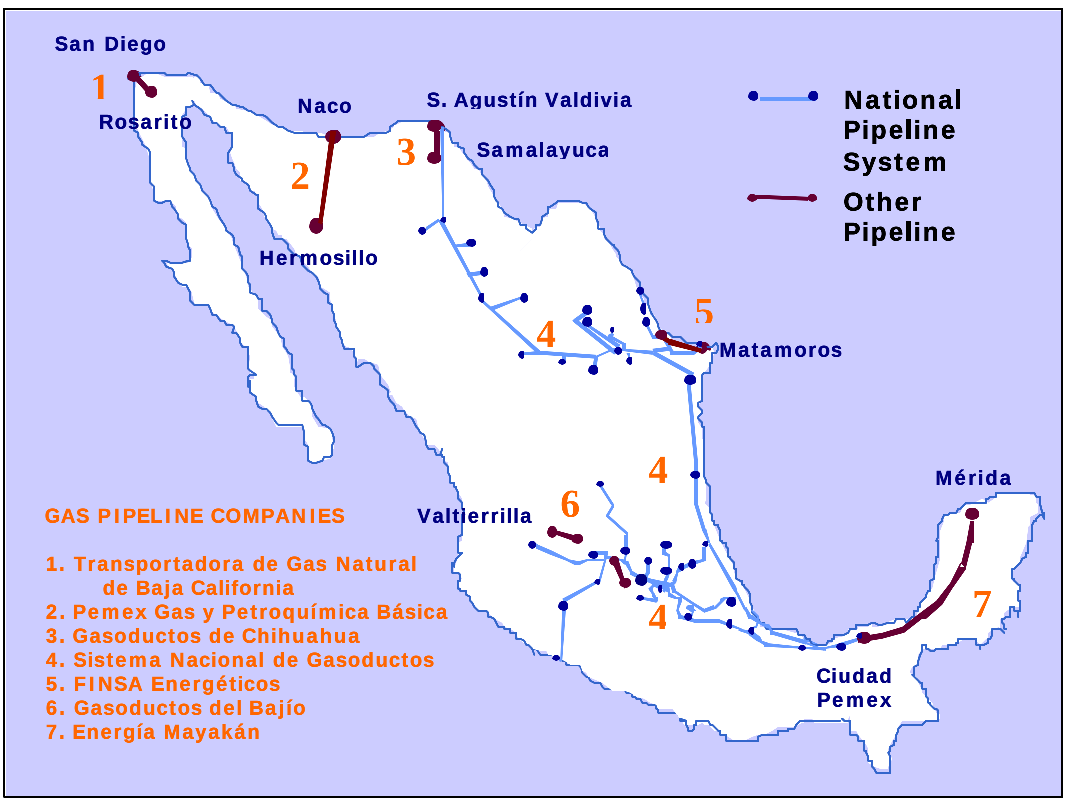
It can be seen from the chart that in real 2000 US dollars, the price of gas to industrial users and electricity generators more than doubled from $67 per tonne of oil equivalent in 1995 to $165 per toe in 2001. But afterwards, prices for gas in Mexico subsided to around the levels that had prevailed in the late 1990s, in line with moderating price trends in the rest of North America.[125]

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

As indicated above, Mexico had some 11,666 km of high-pressure pipeline that could carry 10,802 Mcf (305.9 Mcm) of gas per day in 2001. The pipeline network is best developed in the gas-producing states of Campeche, Tabasco and Veracruz in the Southeast and Nuevo León and Tamaulipas in the Northeast. It extends as well to Mexico City (Distrito Federal), Guanajuato, Hidalgo, Puebla and Querétaro in the Centre; Chihuahua, Coahuila and Durango in the North; Chiapas and Yucatán in the Southeast; and Aguascalientes, Jalisco, Michoacán and San Luis Potosí in the West. Tamaulipas, Chihuahua and Coahuila are also connected with the gas transmission network in the United States. Baja California and Sonora in the Northwest, which are not linked to the Mexican gas transmission grid, are connected with pipelines in the United States as well.[126]

Figure 52 Mexico's Natural Gas Pipeline Network in 2002



Source: Secretaría de Energía

125 International Energy Agency (1997), pages II.19-21. IEA (2002a), pages III.30-32. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

126 Secretaría de Energía (2003).

It is anticipated that the transmission grid will be expanded substantially to satisfy demand growth and to relieve congestion on the network in the North and Centre. Pipelines might also be extended to some areas that are not yet connected to the transmission grid. These include Baja California Sur, Colima, Guerrero, Nayarit, Oaxaca and Sinaloa on the Pacific Coast, Quintana Roo in the Southeast, and Zacatecas in the Centre. The government is studying the possibility of enhanced interconnections in the North with the southern United States.[127]

Mexico's 21 local gas distribution grids incorporated some 28,042 km of pipeline in 2001, with 1,490 Mcf (42.2 Mcm) per day of capacity. Gas is distributed in only a few of Mexico's major metropolitan areas, so just 12 percent of the population can access gas from existing transportation networks. However, there are plans to improve access to gas by small residential and commercial consumers by expanding the number of distribution grids to include a hundred towns and cities.[128]

INFRASTRUCTURE INVESTMENT INCENTIVES

The gas market reforms of 1995 were specifically directed at infrastructure deficiencies that were seen as limiting industrial, commercial and residential gas use. Since budget restrictions limited the construction of new transmission and distribution pipelines by the government, the regulatory regime was designed to encourage their construction by private parties. Permits for transportation, storage and distribution are granted with an initial duration of 30 years and can be extended for periods of up to 15 years thereafter. In the case of distribution, the first party to develop a pipeline system in a given geographical area is granted exclusive rights to distribution in that area, providing incentives to develop distribution networks over long periods of time. A further spur to infrastructure development is provided by regulations that allow gas users to build physical links directly to the gas transmission network. The opportunity for such physical bridging is limited to consumers of at least 60,000 cubic metres during the first two years of a distributor's exclusivity and 30,000 cubic metres during the next two years, but is not restricted thereafter.[129] Pipelines are built on a merchant basis, without a guaranteed rate of return, so decisions to build are based on private firms' evaluations of whether a profit can be earned while permits are in effect.[130]

127 *Ibid.*

128 Secretaría de Energía (2001), pages 37-39, and (2003). Comisión Reguladora de Energía (2001b).

129 Comisión Reguladora de Energía (1996).

130 Secretaría de Energía (2003).

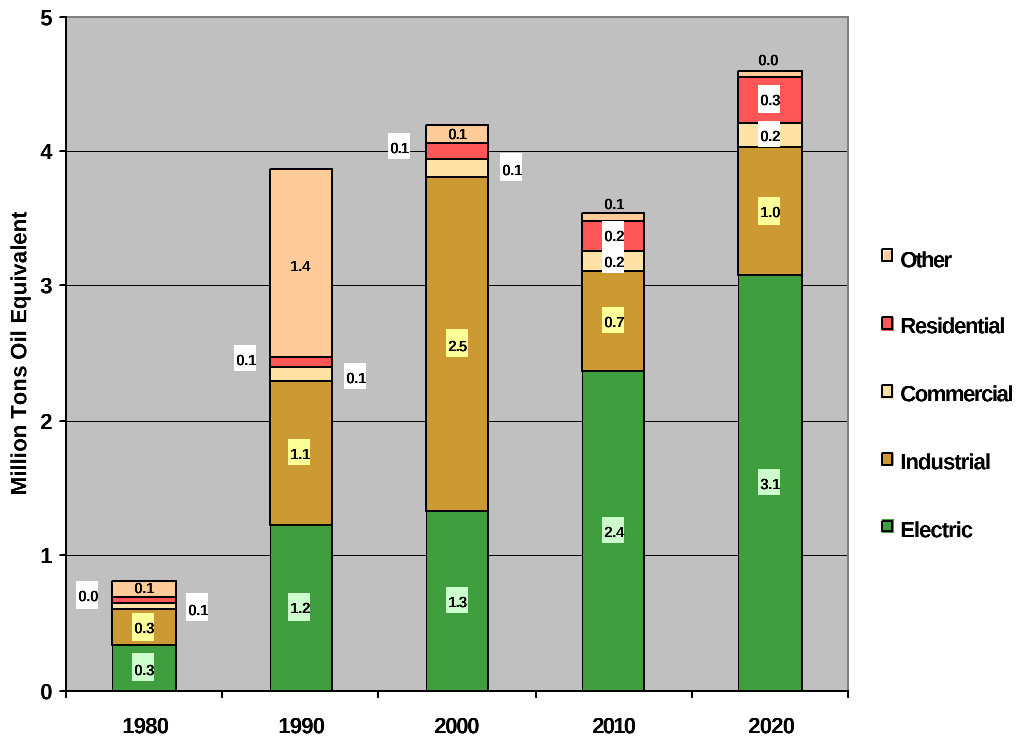
NEW ZEALAND

GAS MARKET SETTING[131]

New Zealand produces a modest amount of natural gas, which allows the economy to be completely self-sufficient in domestic gas supply.

- Production and primary supply of gas are projected to increase just slightly from 4.2 Mtoe in 2000 to 4.6 Mtoe in 2020, with demand declining by 1.7 percent per year from 2000 to 2010 and increasing by 2.6 percent yearly from 2010 to 2020.

Figure 53 Evolution of Natural Gas Use in New Zealand, 1980-2020



New Zealand's natural gas use is somewhat diversified but concentrated in power production and industry. About one-third of all gas demand emanates from the electric power sector, and the share is trending upward rapidly. Roughly three-fifths of demand occurs in the industrial sector, but the relative importance of this sector is fast diminishing. Remaining gas use is divided between residential, commercial and oil industry uses, with the residential share increasing over time.

- Rapid growth is anticipated in gas use for electric power generation, with demand substantially more than doubling from 1.3 Mtoe in 2000 to 3.1 Mtoe in 2020, so that the power sector's share of gas use more than doubles from 32 to 67 percent.
- Industrial gas use is projected to plummet from 2.5 Mtoe in 2000 to 1.0 Mtoe in 2020, its share of overall gas demand falling by nearly a factor of three from 59 percent to 21 percent, mainly due to the closure of a major methanol plant.

131 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Commercial and residential gas use will likely grow, with the commercial share of gas demand projected to increase slightly from 3.1 percent in 2000 to 3.9 percent in 2020 and the residential share to more than double from 3 percent to 7 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

New Zealand has eight different gas producers, but the largest three accounted for 99 percent of production in 2002. Shell, by far the largest, controlled 76.5 percent of production. Todd followed with a 17.7 percent share, while Swift Energy produced 5.2 percent of the economy's gas.

PRINCIPAL PLAYERS IN NEW ZEALAND'S GAS MARKET

Gas Producers in New Zealand

Shell (Shell Exploration NZ, Shell (Petroleum Mining) Company, Shell Investments NZ), Todd (Todd Petroleum Mining Company, Todd Taranaki)
Southern Petroleum (Southern Petroleum (NZ) Exploration, Southern Petroleum (Ohanga))
Swift Energy NZ, Ngatoro Energy, Greymouth Petroleum Acquisition Company, Australia and New Zealand Petroleum, Bligh Oil and Minerals NZ

Owners and Operators of Gas Transmission Pipelines in New Zealand

Natural Gas Corporation of New Zealand (NGC), Shell (Petroleum Mining) Company, Todd Petroleum Mining Company

Owners and Operators of Gas Distribution Pipelines in New Zealand

Powerco, UnitedNetworks, NGC, Nova Gas, Wanganui Gas

Retail Gas Marketers in New Zealand

Genesis Energy, Auckland Gas, Contact Energy, NGC, Nova Gas, Wanganui Gas

Source: Ministry of Economic Development

New Zealand's gas transmission network is operated by the Natural Gas Corporation (NGC). NGC also owns about two-thirds of the network; the rest is owned by Shell (Petroleum Mining) and Todd Petroleum Mining. There are five distribution companies serving distinct geographic areas. There are also six competing gas retail companies which supply gas to final customers.[132]

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in New Zealand are partially unbundled in that ownership of most of the gas transportation network is separate from ownership of production. But Shell and Todd, the dominant producers, still control a significant portion of the high-pressure transmission network. And while there are several competing gas retailers, there remains substantial integration between retailing and transportation. NGC, which controls most transmission, also distributes and retails gas. Nova Gas and Wanganui Gas each both distribute and retail gas as well.

Third party access to transportation services is limited. About three-fourths of all the gas used in the economy is produced from the Maui gas field and transmitted via the Maui pipeline; gas from other fields may not use the Maui pipeline before 2009. There are currently no legal or regulatory provisions for ensuring access to gas transportation facilities by competing producers.

[132] Ministry of Economic Development (2003), pages 80-82. Production shares for each firm are calculated from net production and ownership shares in different fields.

MARKET MODEL AND COMPETITION

The New Zealand gas market does not fit any of the market models very neatly. In some areas, there is a degree of wholesale and retail competition, with customers able to choose among gas producers and suppliers. The gas industry was deregulated in 1993, along with the electricity industry. Since then, there have been no wholesale gas price controls and no monopoly franchise areas for gas supply. Retail price controls on gas had been allowed to lapse even earlier. More recently, in September 2002, the largest owner of transmission and distribution pipelines, NGC, divested to Genesis Energy its function of retail marketing to small "mass market" customers. So the economy appears in principle to have adopted a retail competition model for its gas market.

Yet the market remains in some respects like a vertically integrated monopoly since production of gas is highly concentrated. The Maui field, which produced 75.3 percent of the economy's gas in 2002, is owned by a partnership between Shell (with a 93.75 percent share) and Todd Energy (with 6.25 percent). The Kapuni field, which accounted for 11.8 percent of production, is also owned by Shell and Todd (each with a 50 percent share). The McKee and Mangahewa fields, with 2.7 percent and 4.4 percent of production respectively, were owned entirely by Todd.[133] All of these fields, which together produced 94 percent of the economy's gas, are operated by Shell Todd Oil Services. Thus, the two largest ostensible competitors jointly produce nearly all of the economy's gas. Moreover, NGC's Maui pipeline transmits gas only from the Maui field and not from competing sources, so retailers and customers may often be unable to choose among different producers.

Looking forward, however, the government clearly intends to establish an unambiguous retail competition regime by the end of 2004. "The expected end of the life of the Maui gas field," with "production from an increased number of smaller gas fields," the government finds, "signals the need for … more sophisticated pro-competitive market arrangements." Thus, the gas industry has been asked to provide recommendations on how to implement a more competitive marketplace. This would include "establishment of an open access regime across all high-pressure transmission pipelines so that gas market participants can access transmission pipelines on reasonable terms and conditions" as well as "consistent standards and protocols … so that gas market participants can access distribution pipelines on reasonable terms and conditions." The government stresses that "open access arrangements need to provide non-discriminatory access to all potential users" and notes that it "will consider regulatory solutions" if industry does not make adequate progress towards designing and implementing a more competitive gas market regime.[134]

A related issue is vertical integration between gas transmission and power markets in New Zealand. NGC, which controls gas transmission pipelines, also had effective controlling interests in five electric power plants until quite recently.[135] In purchasing gas for these power plants, NGC may well have favoured the gas that it transported by itself over gas that was transported by others, even if its own gas was more costly, in areas where the power plants did not face effective competition from other electricity generators. However, NGC ended its involvement in the retail electricity market in August 2001 and divested all of its power plants during 2002. Nonetheless, insofar as power producers continue to rely on the dominant consortium for their gas supplies, the scope for competition among them will be mainly limited to capital and non-fuel operating costs.

PRICE TRENDS

Following the deregulation of wholesale gas transactions and elimination of gas distribution franchises in 1993, gas prices in New Zealand increased dramatically but then subsided. Between 1993 and 1997, real gas prices in 2000 US$ increased by about three-fifths for households (from

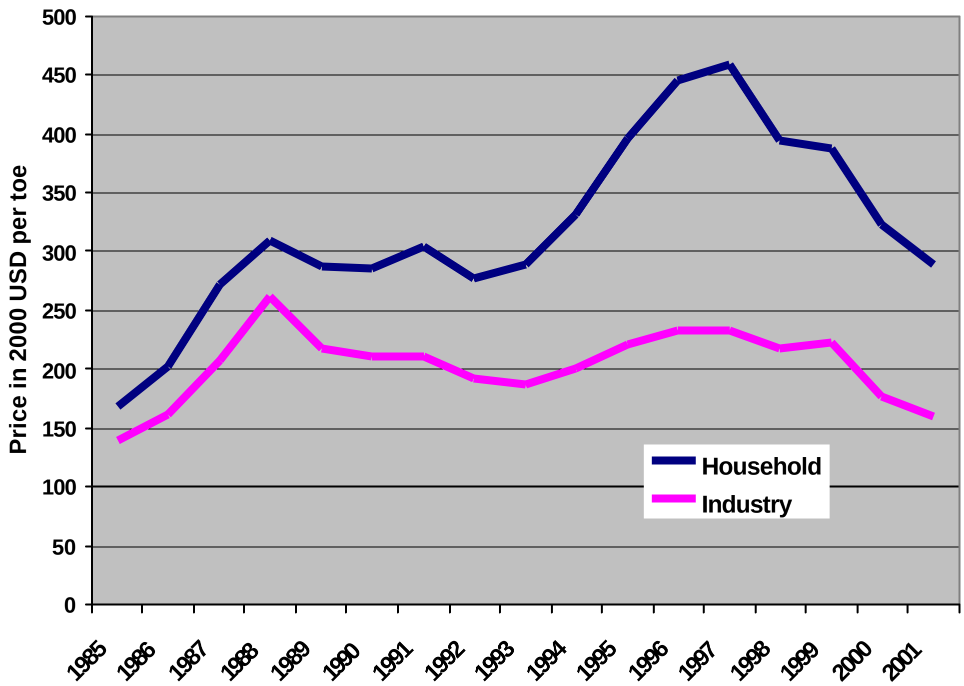
133 *Ibid.*

134 Ministry of Economic Development (2002a).

135 Ministry of Economic Development (2002b), pages 81, 108-9. NGC had sole ownership of the 365 MW Taranaki combined cycle plant in Stratford and the 32 MW Cobb hydro station in Takaka, owned half of the 118 MW Southdown cogeneration plant in Auckland and the 25 MW Kapuni cogeneration plant in Kapuni, and owned 46.5 percent of the small Silverstream landfill plant in Upper Hutt.

$289 to $459 per tonne of oil equivalent), and one-fourth for industry (from $186 to $233 per toe). This may well reflect the lack of effective competition with respect to the four-fifths of the economy's gas that comes from the Maui field. But prices then began to decline, so that real prices in 2001 were hardly changed for households ($290 vs $289 per toe) and 15 percent lower for industry ($159 vs $186 per toe) than they had been at the time of deregulation. This could reflect growing competition among gas producers and retail gas suppliers over time.[136]

Figure 54 Natural Gas Prices in New Zealand, 1985-2001



Sources: International Energy Agency, US Department of Commerce

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

New Zealand has just one main natural gas transmission facility, the 308 km Maui pipeline. The Pohokura pipeline is expected to bring additional gas from offshore Taranaki by around 2006. There is a well-developed gas distribution network on the North Island, with some 2,600 km of distribution pipelines serving major towns and cities.[137]

INFRASTRUCTURE INVESTMENT INCENTIVES

New Zealand's incentives for investment in gas transmission and distribution infrastructure appear to be adequate, in view of the infrastructure that has been put in place. Since deregulation of the gas industry in 1993, there have been no guaranteed returns on such infrastructure. Hence, decisions about extending the pipeline network are entirely based on a market assessment of whether there will be adequate additional sales of gas to justify the required investment.

136 International Energy Agency (1997) pages II.19-21, IEA (2002a) pages III.30-32. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

137 Ministry of Economic Development (2002c).

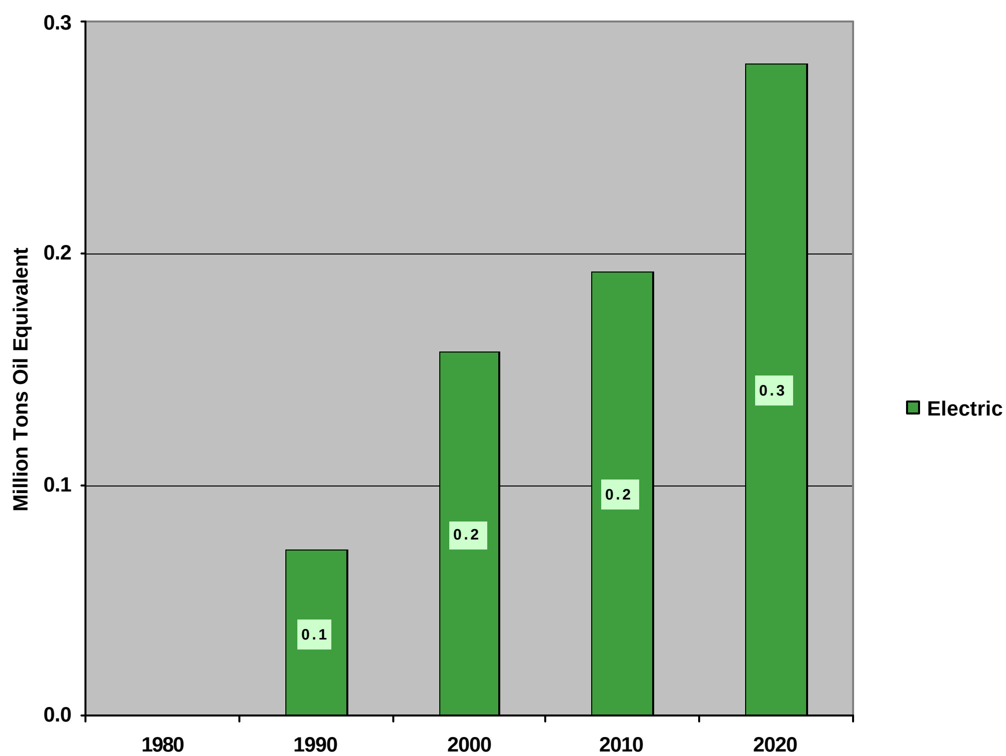
PAPUA NEW GUINEA

GAS MARKET SETTING[138]

Papua New Guinea produces a small amount of natural gas, which allows the economy to be self-sufficient in domestic gas supply. A major increase in production is anticipated between 2005 and 2010, which would be associated with completion of pipelines for gas exports to Australia.

- Primary supply of gas to the domestic economy is projected to increase from 0.16 Mtoe in 2000 to 0.28 Mtoe in 2020, with demand growth averaging 2.0 percent per year from 2000 to 2010 and 3.9 percent per year from 2010 to 2020.

Figure 55 Evolution of Natural Gas Use in Papua New Guinea, 1990-2020



Practically all of Papua New Guinea's limited natural gas use is devoted to electric power production, and this situation is expected to persist indefinitely.

- Use of gas for electricity generation is projected to grow by roughly half from 0.2 Mtoe in 2000 to 0.3 Mtoe in 2020, its share of gas demand remaining near 100 percent.

138 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Several different private companies are involved in the production of gas in Papua New Guinea. However, they are organised into three consortia, each of which has sole rights to produce oil and gas from a particular field. At present, gas is produced for sale only at the Hides field, amounting in 2001 to 5.2 Bcf in total or 0.4 Mcm per day, for use in electric power plants owned by the Papua New Guinea Electricity Commission (Elcom). Gas at the other fields, lacking a downstream market, is reinjected for later use, enhancing current oil output.

PRINCIPAL PLAYERS IN PAPUA NEW GUINEA'S GAS MARKET

Gas Producers in Papua New Guinea

Hides field (current production): Consortium of ExxonMobil, Oil Search, Santos
Kutubu field (prospective production): Consortium of ExxonMobil, Oil Search, ChevronTexaco, Japan PNG Petroleum, Orogen Minerals, Mineral Resources Development Company
Gobe field (prospective production): Consortium of ExxonMobil, Oil Search, ChevronTexaco, Japan PNG Petroleum, Orogen Minerals, Gobe Landowners

Owners and Operators of Gas Transmission and Distribution Pipelines in PNG

Hides field: Consortium of ExxonMobil, Oil Search, Santos
PNG Gas Project (export pipeline): Consortium of ExxonMobil, Oil Search, ChevronTexaco, Japan PNG Petroleum, Mineral Resources Development Company

Sources: IEEJ, PNG Gas Project, Dow Jones Business News

Transmission and distribution of gas from the Hides field is performed by the same consortium that produces gas from the field. The PNG Gas Project, which may link all three gas fields with downstream markets in Australia as early as 2005, is also owned by a consortium which has many of the same owners as the gas fields.[139]

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in Papua New Guinea are not effectively unbundled. While the consortia for gas production are distinct from the consortia for gas transmission and distribution, they have many of the same participants. There are no legal requirements for information firewalls between them, so their apparent functional separation appears unlikely to be effective.

There is also no legal requirement to give competitors access to the transportation and distribution pipelines that are in place. In any event, there is only one consortium selling gas at present, and if additional consortia start selling gas, they would seem more likely to cooperate than to compete in view of the similar compositions. Consequently, there is currently no competitor at all, and prospectively no real competitor, to whom transportation services might be granted.

MARKET MODEL AND COMPETITION

Papua New Guinea's gas market conforms closely to the vertically integrated monopoly model. At present, a single consortium undertakes the production, transmission and distribution of gas. While additional production and transport consortia seem likely to enter the gas market in coming years, these consortia are also likely to have controlling shares held mainly by the same companies.

139 IEEJ (2002a), pages 387-8. PNG Gas (2002). *Dow Jones Business News* (2002).

There is some degree of vertical integration, as well, between Papua New Guinea's gas and electricity markets. All of the economy's power is produced and transported by the Papua New Guinea Electricity Commission (Elcom). While four-fifths of this electricity is generated from hydropower, gas is generally the favoured fuel for new power stations, so it plays an important role at the margin.[140] Elcom can buy gas from only a single consortium, whose only domestic customer is Elcom. Thus there appears to be a kind of bilateral monopoly-monopsony situation where the gas consortium may well be able to negotiate to raise its gas prices to Elcom to cover inefficiencies that might arise in gas production, processing, or transportation. There would be little reason for Elcom to resist an increase in gas prices since it could pass on the resulting increase in generating costs in its rates to electricity customers, who have no other source of power.

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Domestically, the transmission and distribution pipelines that are needed to deliver gas to power producers should expand as gas-fired power generation grows. There are no plans to extend a distribution grid to residential or commercial customers since space heating requirements are few, other fuels are used for cooking, and air conditioning can be provided by electricity.

The bulk of planned gas infrastructure investment in Papua New Guinea relates to exports. The PNG Gas Project's pipelines would extend overland for 160 km from the Kutubu and Gobe fields to the port of Kutubu in Papua New Guinea, 515 km under sea to Cape York in Australia, and 1,440 km within the Australian state of Queensland to Brisbane. The pipelines would carry 175 million cubic feet or 4.96 Mcm of dry gas per day for export to Australia.[141]

INFRASTRUCTURE INVESTMENT INCENTIVES

Papua New Guinea's incentives for investment in transportation infrastructure for domestic gas use and exports appear to be adequate. Since prices for exported gas are market-determined, the planned gas export pipeline ought to succeed if its gas would be economical relative to other sources of gas supply in Australia. Domestically, the transportation consortium can charge Elcom an ample price for gas, given its monopoly on gas supply and Elcom's ability to pass its fuel costs on to electricity customers. Thus, it can easily earn a good enough return on the limited network of pipelines that is required to deliver such gas to make any needed network expansion worthwhile.

140 High Commission of Papua New Guinea, Canberra (2001).

141 IEEJ (2002a), pages 387-8. *Pipe Line & Gas Industry* (2001).

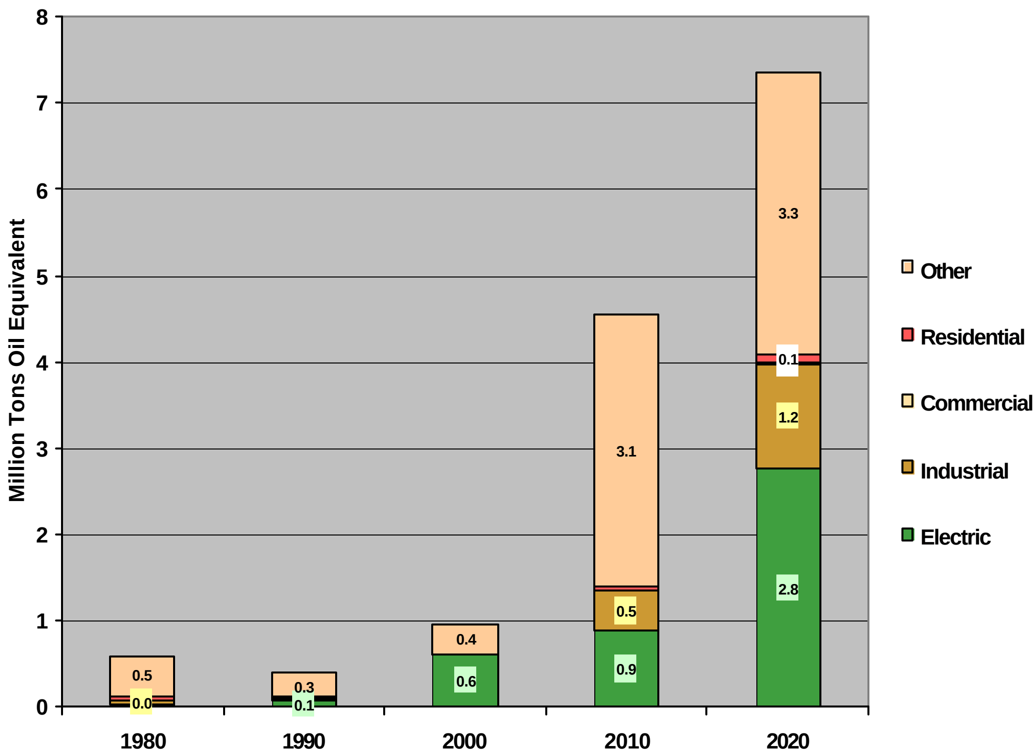
PERU

GAS MARKET SETTING[142]

Peru produces a small but rapidly growing amount of natural gas that makes the economy entirely self-sufficient in domestic gas supply.

- Production and primary supply of gas are projected to increase from 1.0 Mtoe in 2000 to 7.4 Mtoe in 2020, with very rapid demand growth of 16.8 percent per annum from 2000 to 2010 and further demand growth of 4.9 percent yearly from 2010 to 2020.

Figure 56 Evolution of Natural Gas Use in Peru, 1980-2020



Almost all of Peru's natural gas use is currently devoted to electric power generation and oil refining. Substantial gas use is anticipated in the industrial sector, but not the commercial or residential sector.

- Use of gas for electric power generation is projected to grow rapidly, quadrupling from 0.6 Mtoe in 2000 to 2.8 Mtoe in 2020. But the power sector's share of gas demand would drop sharply from 63 percent to 38 percent with the introduction of gas for industry and gas liquefaction.
- Industrial use of gas, which was nil in 2000, is projected to grow to 1.2 Mtoe by 2020, accounting for a 17 percent share of the gas market.

142 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Use of gas for non-electric energy transformation is projected to grow from 0.4 Mtoe in 2000 to 3.2 Mtoe in 2020, so that "other" use (including some for transport) grows from 36 percent to 44 percent of the market.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Several different private companies are involved in the production of gas in Peru. However, they are organised into two consortia, each of which has sole rights to produce gas from a particular field for 40 years. The Aguaytia field began commercial operation in 1998 at 55 million cubic feet (1.56 Mcm) per day. The Camisea field should operate by 2004 at some 6.5 Mcm per day.

PRINCIPAL PLAYERS IN PERU'S GAS MARKET

Gas Producers in Peru

Aguaytia field: Consortium of Duke Energy International, El Paso Energy International, Illinova Generating Company, Maple Gas Company, Power Markets Development Company, and Scudder Latin America Power Fund

Camisea field: Transportadora de Gas del Peru (joint venture between Hunt Oil Corporation of the US, Pluspetrol of Argentina, and SK Corporation of Korea)

Owners and Operators of Gas Transmission and Distribution Pipelines in Peru

Aguaytia field: Consortium of Duke Energy International, El Paso Energy International, Illinova Generating Company, Maple Gas Company, Power Markets Development Company, and Scudder Latin America Power Fund

Camisea field: Consortium of Hunt Oil Corporation of the US, Pluspetrol and Tecgas of Argentina, SK Corporation of Korea, Sonatrach of Algeria, and Grana y Montero of Peru

Source: Ministry of Energy and Mining

Gas transmission and distribution of gas in Peru is also performed by two consortia, each of which has been granted rights to transmit and distribute gas from a given field for 33 years. In each case, the transmission and distribution consortium for a field includes the same participants as the production consortium, though it also includes additional participants in the Camisea case.[143]

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in Peru are not effectively unbundled. While the consortia for gas production are distinct from the consortia for gas transmission and distribution, they have many of the same participants. There are no legal requirements for information firewalls between them, so they are not functionally separate in any true sense.

In theory, gas concessions provide for open access to transmission and distribution grids. However, it does not appear that a regulatory apparatus has been put in place to ensure such access in view of the fact that transmission and distribution consortia have a business incentive to discriminate in favour of the associated production consortia which have many of the same owners.

[143] Ministry of Energy and Mining (2003).

MARKET MODEL AND COMPETITION

Peru's gas market would seem most closely to resemble the vertically integrated monopoly model. In each production area, there is just one producing consortium and one transmission and distribution consortium, and controlling shares in each consortium are held by the same companies. Since the production areas are geographically quite distinct, the market effectively functions like two vertically integrated monopolies working side by side. Aguaytia, northeast of Lima, delivers gas to an electric power station. Camisea, southeast of Lima, will deliver gas to the capital city.

Since the gas and electric components of the Aguaytia project were developed in parallel, and since Aguaytia gas is the only source of fuel for the associated gas-fired power plants, the gas and electricity markets are vertically integrated in the Aguaytia area. But there is no integration of gas and electricity markets in the rest of Peru, where gas is not used for power production at all. Gas accounted for just 4 percent of Peru's electricity generation in 2000, all of it from Aguaytia.

State utility ElectroLima and most of state utility Electro Peru were privatised in 1992, while a competition law passed in 1997 prohibits control of more than 15 percent of power generation, transportation or distribution by any one firm. As a result, competing private firms control about 65 percent of Peru's electric generating capacity.[144] If power producers outside of Aguaytia should decide to build gas-fired plants in the future, they would retain a great deal of flexibility to switch back to other fuels if gas prices rose too high. This would probably limit the extent to which the Camisea consortium or other gas suppliers were able to raise prices above competitive levels.

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Peru currently has just 280 km of natural gas transmission pipelines, all linking gas fields with gas fired-power plants in the integrated Aguaytia project. Another 697 km of transmission pipelines are under construction from the Camisea gas field to Lima and Callao. As part of the Camisea project, gas distribution networks are also to be built in those two cities. The transportation elements of the Camisea project are estimated to require investment of US$700 million exclusive of financing or US$800 million including financing.[145]

INFRASTRUCTURE INVESTMENT INCENTIVES

Concessions for the production, transmission and distribution of gas are granted by the state oil company, Perupetro. Regulation and licensing of gas concessions, as well as negotiation of contract terms for these concessions, are all within Perupetro's remit. The 1999 Law for the Promotion for the Natural Gas Industry allows Perupetro to grant a contractor rights to exploit proven gas reserves for a given period of time, in return for the contractor's guarantee to supply gas to the national market. Gas is to be sold to all clients under similar conditions.[146]

Investment incentives for construction of the transmission and distribution infrastructure required to deliver the output of particular gas fields in Peru appear to be adequate. Contracts for the main pipeline networks provide an assured minimum annual capacity payment. On the other hand, there does not appear to be a generalised system in place for encouraging construction of transportation infrastructure that is not associated with pre-identified gas production projects. The lack of general rules could slow the development of Peru's gas market over the longer term.

144 APERC (2002b), page 87.

145 Ministry of Energy and Mines (2002b). Inter American Development Bank (2003).

146 Government of Peru (1999).

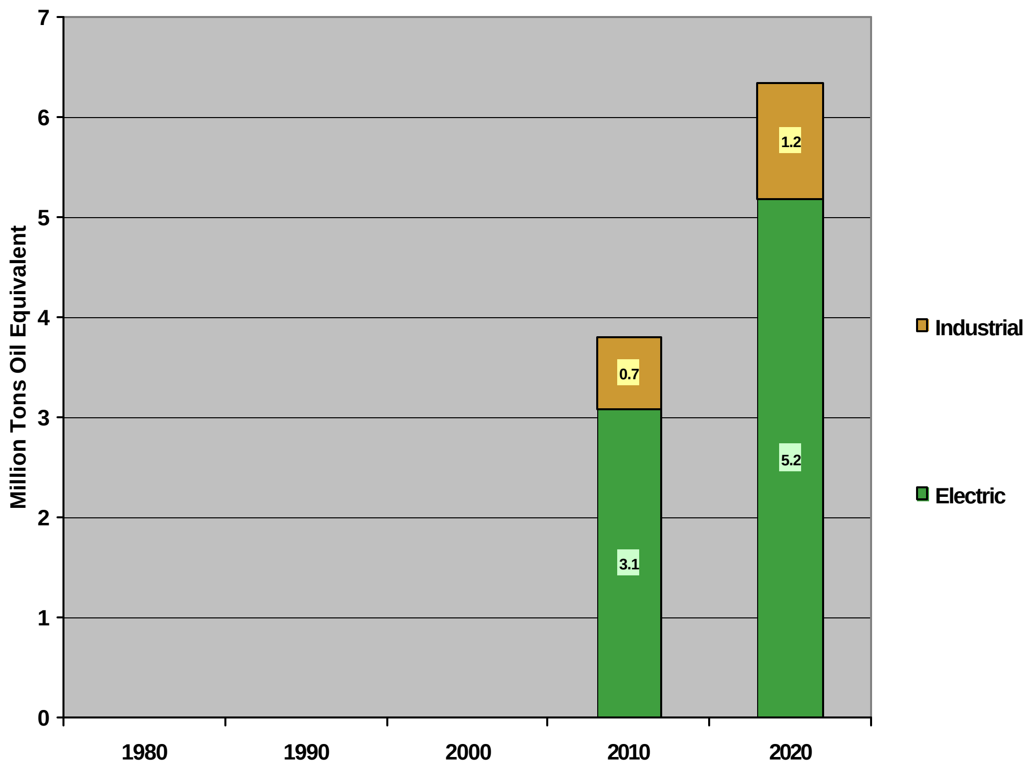
PHILIPPINES

GAS MARKET SETTING[147]

The Philippines began to consume significant amounts of gas in 2002 and are currently self-sufficient in gas production but are not expected to remain so as demand expands.

- Gas production is projected to grow to some 4.1 Mtoe in 2020, at which time demand is projected to exceed production by about 56 percent.
- Imports of gas, mostly through LNG facilities, are projected at 2.3 Mtoe in 2020.
- Primary supply of gas to the domestic economy is projected to increase rapidly from a very small base to about 6.4 Mtoe in 2020, with average annual growth rates of 85.2 percent from 2000 to 2010 and 5.3 percent from 2010 to 2020.

Figure 57 Evolution of Natural Gas Use in the Philippines, 2000-2020



Natural gas use in the Philippines will initially take place almost entirely in the electric power sector. Substantial gas use is also anticipated in the industrial sector.

- Use of gas for electric power generation is projected to grow rapidly to 5.2 Mtoe by 2020, at which time it would account for 82 percent of overall gas demand.
- Industrial use of gas, meanwhile, is projected to grow to 1.2 Mtoe by 2020, making up 18 percent of the overall gas market.

---

147 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC. There are plans, as well, not reflected here, for use of gas in vehicle fleets for public transportation in major cities.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

While three different private companies are involved in Philippines gas production, they form a single consortium called SPEX which has a 25-year concession to produce gas from the Malampaya field. Output from the field reached 401 million cubic feet (11.4 million cubic metres) per day in 2002 and is expected to rise somewhat further as production experience is gained. As the market develops, there could also be imports of liquefied natural gas (LNG) from Brunei Darussalam, Indonesia or Malaysia.[148]

PRINCIPAL PLAYERS IN THE PHILIPPINES GAS MARKET

Gas Producers in the Philippines

Malampaya field: SPEX Consortium (owned 45 percent by Shell Philippines Exploration,
45 percent by ChevronTexaco,
10 percent Philippine National Oil Co-Exploration Corporation)

Owners and Operators of Gas Transmission Pipelines in the Philippines

SPEX Consortium

Source: Philippine Department of Energy

The gas that is currently produced from Malampaya is dedicated to 2,700 megawatts of gas-fired power plants, which are owned by two different power-producing consortia, under long-term contracts that extend through 2021 and 2023, respectively. When they are all in operation, these plants will require about 434 Mcf of gas per day. A single offshore transmission pipeline, owned by SPEX, links Malampaya with the power plants. This pipeline has a capacity of 650 Mcf per day, about two-thirds of which is needed to serve the power plants. There is at present no distribution grid for use of gas by industrial, residential or commercial customers.[149]

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in the Philippines are not effectively unbundled. The consortium that owns and operates the high-pressure gas transmission pipeline is the same as the consortium that produces the gas it carries. In any event, there are no competing sources of gas at present.

MARKET MODEL AND COMPETITION

The natural gas market in the Philippines most closely conforms to the vertically integrated monopoly model at its current early stage of development. Initial development of the Malampaya field, together with the pipeline linking it with the main island of Luzon, was completed only in late 2002. Most of the gas from the field is dedicated to specific gas-fired electric power plants, which have take-or-pay contracts for the gas. The field was developed with contractual assurances that the gas would be used by the power plants, and the power plants were built with contractual assurances that the field and offshore pipeline would be developed. Thus, the market consists of bilateral contracts integrating gas production and transmission with power sector customers.

---

[148] Department of Energy (2002b and 2003).

[149] IEEJ (2002a), pages 402-7. Platts (2003). Department of Energy (2002a). Two of the plants, Santa Rita (1,000 MW) and San Lorenzo (500 MW) are owned by First Gas Power Company, a consortium formed by First Gas Holdings Corporation (51 percent), Meralco (the Manila power distribution company, 9 percent) and British Gas (40 percent). A third plant, Ilijian (1,200 MW), is owned by a consortium formed by the Korean Electric Power Corporation (KEPCO, 51 percent), Mitsubishi (21 percent), Kyushu Electric Power (8 percent), and Southern Energy Philippines (20 percent).

Looking forward, however, the Philippine gas market may come to more closely resemble the wholesale competition model. The Department of Energy (DOE) and Energy Regulatory Commission (ERC) are actively planning for a more open gas marketplace in which additional sources of domestic gas are developed, along with pipelines and LNG facilities for gas imports, and wholesale business customers can choose freely among available sources of supply. As the new sources have not yet been developed, this planning is still at a fairly conceptual stage. However, a natural gas circular that DOE issued in 2002 envisions a marketplace in which access to gas pipelines is provided to all suppliers on a non-discriminatory basis, to the extent that capacity of these facilities is not required by the owner or operator to serve its own customers or to honour third-party contracts for gas transportation. Transmission and distribution utilities are to inform DOE of "the technical and economic feasibility of transporting Natural Gas for third parties by using spare capacity, if any, or expanding the rated capacity of the Pipeline" in question.[150]

In this model, gas and electric distribution companies would buy gas, through pipelines and LNG terminals owned by other companies, from the least-cost gas supplier. While competition would initially be limited to spare capacity on existing pipelines, the scope for competition would expand as new pipelines and LNG facilities are built. Key issues, in this context, are the period allowed for transition from the limited vertically-integrated market now in place and financial terms under which currently dedicated pipeline facilities would be unbundled from production and use.

There is a significant degree of integration between gas and electricity markets in the Philippines, though it may well diminish over time. For the 16 percent of the economy's electricity that was generated from gas in 2002, there was only a single gas supplier, engaged under long-term contract. But if indigenous gas production expands and LNG facilities are built as anticipated, multiple suppliers of gas should evolve. The Electric Industry Reform Act of 2001 provides for separation of electricity transmission and distribution from generation and retail supply.[151] Thus, competing gas-fired generators may eventually arise, obtaining gas from alternative sources.

GAS MARKET REGULATIO N AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

The Philippines have 526 km of gas transmission pipelines linking the offshore Malampaya gas field with the Ilijan, Santa Rita and San Lorenzo electric power plants. There is also an 8 km distribution pipeline system in Fort Bonifacio Global City in metropolitan Manila.[152]

INFRASTRUCTURE INVESTMENT INCENTIVES

The DOE Circular on Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas, issued in 2002, provides economic and technical guidelines for construction and operation of transmission and distribution pipelines and related facilities. The Circular states that prices of transmission and distribution and supply shall continue to be regulated until such time as the Secretary of Energy determines that markets are effectively competitive. But there are few specifics on pricing other than that rates should be "just and reasonable." [153]

Investment incentives for construction of the transmission infrastructure required to deliver gas from the Malampaya gas field were apparently adequate. The situation is less clear for pipelines that have not yet been built. As nearly all output from Malampaya so far is dedicated to power production, there is currently almost no gas distribution grid. Thus, it is difficult to assess whether

150 Department of Energy (2002a), Rule 11 and Annex II.

151 APERC (2002b), pages 92-93. IEEJ (2002a), pages 399 and 402.

152 Department of Energy (2002d).

153 Department of Energy (2002a), Rule 15.

investment incentives for construction of a distribution grid will be adequate at such time as gas supplies may expand to support additional demand in the residential or commercial sector.

Figure 58 Existing and Planned Gas Pipeline Infrastructure in the Philippines

Sources: APERC (2000c), Department of Energy (2002d).

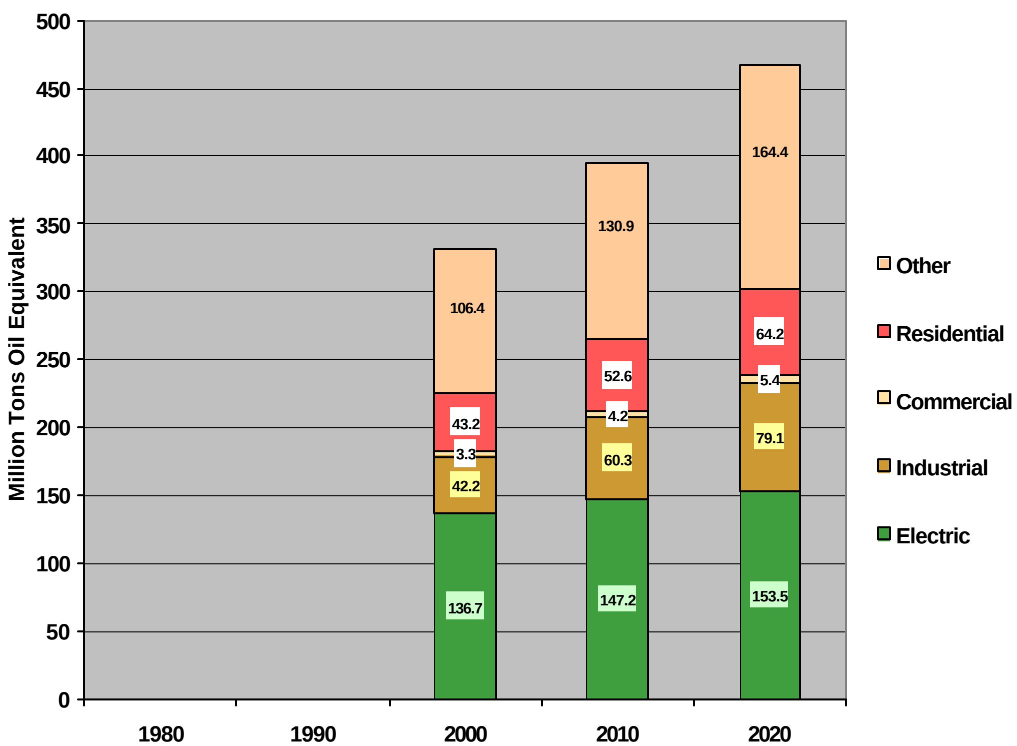
RUSSIA

GAS MARKET SETTING[154]

Russia is the world's largest gas producer and exporter, with gas supplied to the economy almost entirely from domestic production.

- Gas production is projected to increase very substantially from 507 Mtoe in 2000 to 678 Mtoe in 2020, but the net exports as a share of production are projected to decline from 35 percent to 31 percent due to growing domestic demand.
- Primary supply of gas to the domestic economy is projected to grow markedly in absolute terms from 332 Mtoe in 2000 to 466 Mtoe in 2020, despite modest growth rates averaging 1.8 percent per annum in the decade from 2000 to 2010 and 1.7 percent per annum in the decade from 2010 to 2020.

Figure 59 Evolution of Natural Gas Use in Russia, 2000-2020



Russia's natural gas use is somewhat diversified. Nearly three-quarters of gas use is currently devoted to energy transformation, with a fairly even split between power production, on the one hand, and production of oil, gas and heat on the other. Most of the remaining quarter of gas demand occurs in the industrial and residential sectors, which are expected to grow in relative importance over time.

- Use of gas for electric power generation is expected to increase very slowly from 137 Mtoe in 2000 to 154 Mtoe in 2020, with the power sector's share of gas use declining sharply from 41 percent to 33 percent as other sectors grow faster.

154 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Use of gas for oil and gas production is projected to grow modestly between 2000 and 2020, while the use of gas for heat generation nearly doubles, so that "other" use grows from 106 Mtoe to 164 Mtoe and its share of overall gas use increases from 32 percent to 35 percent.
- Industrial gas use is projected nearly to double from 42.2 Mtoe in 2000 to 79.1 Mtoe in 2020, with its share of total gas demand increasing from 13 to 17 percent.
- Residential gas demand is projected to grow by half from 43.2 Mtoe in 2000 to 64.2 Mtoe in 2020, with its share of overall demand increasing slightly from 13 percent to 14 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

The gas industry in Russia is dominated by state-controlled Gazprom, which accounted for 88 percent of the economy's gas production in 2002. Gazprom has more than 40 subsidiaries and partners covering all phases of the gas industry from extraction to transportation to distribution to processing, as well as some power generating units that are fuelled by gas. It is also the sole exporter of gas from Russia, through its Gazexport arm. Gazprom was initially established in 1989 within the Ministry of the Gas Industry of the Union of Soviet Socialist Republics. It was privatised as a joint-stock company in 1993, and the Russian federal government holds 35.7 percent of its shares. Gazprom plays a prominent role in the Russian economy, contributing 8 percent of GDP and about one quarter of all federal tax revenues or one-fifth of the federal budget.

PRINCIPAL PLAYERS IN RUSSIA'S GAS MARKET

Gas Producers in Russia

Gazprom (88 percent share), Itera (5 percent share),
Lukoil, Rosneft, Surgutneftegaz, TNK, YUKOS

Owners and Operators of Gas Transmission Pipelines in Russia

Gazprom

Owners and Operators of Gas Distribution Pipelines in Russia

Gazprom (controlling about 10 percent of distribution pipeline)
Many small local distribution companies (378 of them in 2000)

Source: International Energy Agency

Of the gas in Russia that is not produced by Gazprom, about half is produced by Itera, an independent trading and production company, and half by oil companies extracting associated gas. Independent producers have acquired about one-third of gas field licenses, as measured by volume of deposits, so their share of production appears likely to increase over time.[155]

Most gas distribution grids in Russia are owned and operated by independent private companies. These companies were privatised in the late 1990s. However, due to financial problems stemming from the failure of many customers to pay for gas that was delivered, many distribution companies soon became insolvent, and more than 50 of them were acquired by Gazprom. In 1999, Gazprom distributed about 17 Bcm of gas to households, industrial firms, combined heat and power systems and cities, accounting for roughly 5 percent of gas consumed.

[155] International Energy Agency (2002f), pages 110, 112, 136.

As of 2000, Gazprom owned about 10 percent of the economy's distribution network. Nonetheless, there remained about 378 distribution companies, about half as many as had existed in the early 1990s but still dominating the gas distribution function in the most of the economy.[156]

UNBUNDLING AND THIRD PARTY ACCESS

The production and transmission of gas in Russia are unbundled only to a limited extent. Gazprom accounts for 88 percent of gas production and controls the entire network of high-pressure gas transmission pipelines. However, a significant and growing share of gas production is undertaken by competitors under a system of negotiated third-party access. In 1997, the government reserved 15 percent of the transmission system's capacity for independent suppliers. In 2001, the government allowed independent suppliers to negotiate for use of any pipeline network capacity not being used by Gazprom. Bids for spare pipeline capacity are fulfilled by Gazprom in proportion to the claimed transportation volumes. A federal antimonopoly committee supervises Gazprom to see that it awards spare pipeline capacity on a non-discriminatory basis. Transmission tariffs, which are regulated by the Federal Energy Commission (FEC), are based on volume and distance but may be two to three times Gazprom's internal transmission costs.

On the other hand, the distribution function is substantially unbundled from production and transmission, with about 90 percent of distribution pipeline owned by independent companies. Also, looking forward, there may be movement toward unbundling of production and transmission. A government resolution on prices and tariffs for gas transportation, issued in December 2000, calls for accounting separation between the different market functions, state regulation of wholesale prices, and organisation of one or more independent gas transmission companies. But it is not clear at what point Gazprom and its competitors might actually face identical transmission charges.[157]

MARKET MODEL AND COMPETITION

The Russian gas market today most closely resembles the vertically integrated monopoly model. While Gazprom does not have a legal monopoly on gas production and controls only a small portion of distribution grids, it clearly remains the predominant gas producer and retains control over the entire high-pressure gas transmission network. Competing producers account for a significant and growing share of the market, but they can only compete on unfavourable terms. Since transmission tariffs for competitors are substantially higher than Gazprom's cost of providing transmission service, Gazprom is often able to deliver gas at a lower cost than competitors even where competitors' gas is less expensive to produce. Moreover, competing producers can only use the transmission grid to the extent that pipeline capacity is available after Gazprom's needs are met.

Looking forward, however, there appears to be potential for the Russian gas market to evolve toward the wholesale competition model. By 2010, independent firms may well account for something like one-fifth of all gas production. Itera projects that it will produce some 80 Bcm per annum by then, accounting for around 14 percent of projected production, and there is little reason to suppose that the current 6 percent share of other independents will significantly shrink. If functionally or operationally separate transmission companies were formed, with information firewalls between them, and if there were improved legal provisions for non-discriminatory access to transmission pipelines, effective wholesale competition could well emerge.

Russia's gas market is vertically integrated with its electricity market to a great extent. Well over half of Russia's electricity generation in 2002 came from gas. The state-owned electric utility, United Energy System of Russia, generated 80 percent of the economy's electricity in 2000 and retains a monopoly on electricity transmission, distribution and retailing, except for the 5 percent of electricity that is self-generated by industry or produced by municipal utilities. The only major competing power producer is the state-owned nuclear power company, Minatom. United Energy System is obliged to purchase its gas through Gazprom, and almost all of its gas is actually

---

156 International Energy Agency (2002f), page 119.

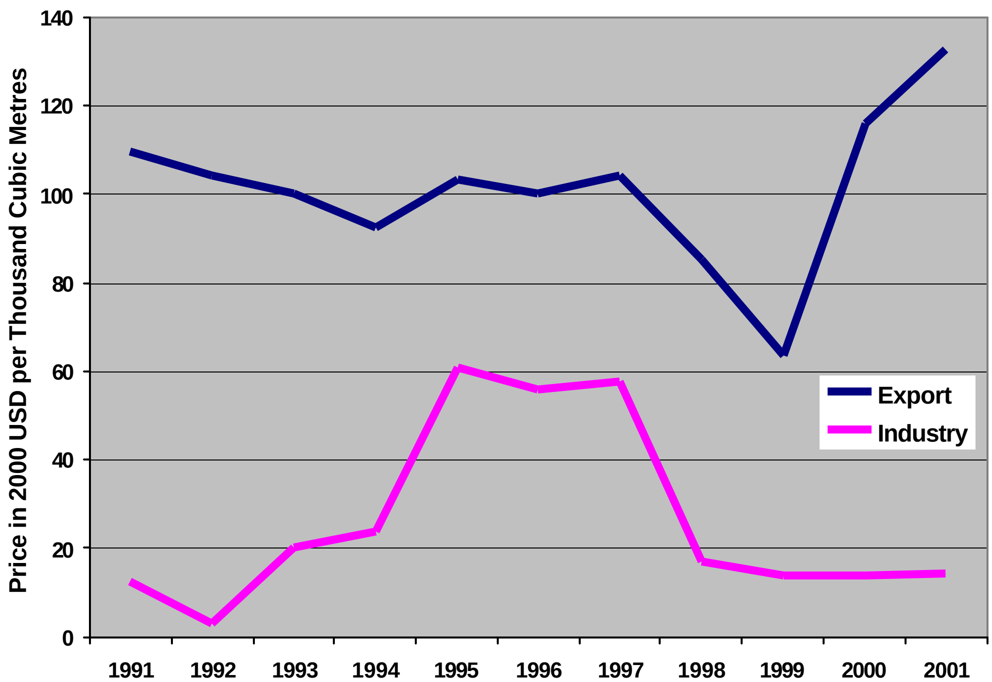
157 *Ibid.*, pages 121-24. Regulated transmission tariffs on different portions of the pipeline network, which are identical for all of Gazprom's competitors, currently vary from US$0.60 to $1.00 per thousand cubic metres per 100 km.

produced by Gazprom since competing gas production is almost entirely destined for export markets or self-use in the petroleum industry. Since United Energy System generates 70 percent of its power from gas, it has limited flexibility to alter its fuel mix in response to prices.[158] Hence, if Gazprom raises its prices to cover inefficiencies, United Energy System will have to pay the higher prices for most of its fuel. United Energy System can then pass on the higher gas prices in electricity rates to its customers, who generally have no alternative source of power. Even if wholesale competition evolved in the gas market, it would remain integrated with the power market since gas from competing producers would still have to be purchased through Gazprom.

PRICE TRENDS

Gas prices in Russia have consistently remained below those that would prevail in a properly functioning marketplace. This can be seen by comparing the market-determined prices for exportation of gas to Europe with the regulated domestic prices paid by Russian industry. The domestic prices have rarely been as high as 60 percent of the export prices and have often been far lower. The low domestic gas prices tend to promote inefficient gas consumption and to curb the incentives for investment in infrastructure for gas production and transportation.

Figure 60 Comparison of Export and Industry Gas Prices in Russia, 1991-2001



Source: International Energy Agency and US Department of Commerce

In its energy strategy, the Russian government foresees raising domestic gas prices to international levels over the next several years. Domestic prices are to be increased by 250 percent from 2000 levels in 2003 and by 350 percent from 2000 levels in 2005, reaching about $50 to $55 per thousand cubic metres. By 2007, domestic and European gas prices are to be equivalent. If such price adjustments can be made, they should go a long way to improving the availability of capital for infrastructure investments to meet domestic gas needs and increase gas exports.[159]

---

158 Minenergo (2001b), pages 116-17. APERC (2002b), page 99. Of 876 TWh generated in 2000, 699 TWh or 80 percent were generated by United Energy System, 131 TWh or 15 percent by Minatom, and 46 TWh or 5 percent by others.

159 International Energy Agency (2002f), pages 126-27, 132-33. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

GAS MARKET REGULATIO N AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Russia faces substantial needs for new gas transmission and distribution lines. According to the International Energy Agency, 70 percent of the 150,000 km of transmission lines in service were commissioned before 1985, and 13 percent are beyond their design life and need replacement. Many existing distribution grids, which serve over 400 localities with some 540,000 km of pipelines, are also in need of substantial upgrades. The government's energy strategy envisions the need for 23,000 km of new transmission lines, including replacements for existing capacity, through 2020, as well as 80,000 km of new distribution lines just through 2005. As much as US$80 billion of investment in transmission and distribution infrastructure will be needed through 2020.[160]

INFRASTRUCTURE INVESTMENT INCENTIVES

The incentives for investment in long-distance transmission infrastructure for delivery of gas to Europe and prospectively to Asia appear to be adequate. Since prices for gas delivered to Europe are market-determined, facilities for the production and transmission of such gas will presumably be built whenever economical. Gazprom does not anticipate additional contracts for exporting gas to Europe before 2008, given the costs of new gas production and pipeline capacity. Exports of gas to Japan, China and Korea from the Kovykta gas field or Sakhalin Island could begin as early as 2010 if new pipelines or LNG facilities are seen as cost-effective and built rapidly.[161]

By contrast, the incentives for investment in transmission and distribution infrastructure for delivery of gas to domestic markets are extremely poor. The prices paid by industrial and residential customers alike are far below market levels. On the one hand, this may mean that existing infrastructure is congested by demand that would disappear if customers were paying a price based on cost, so distribution grids may be more than adequate for some time where they are already in place. On the other hand, artificially low prices mean that funds will generally be unavailable for building new distribution grids and extending the transmission grid to meet them. If prices are raised toward market levels as the government intends, the investment incentives for extending the domestic gas delivery infrastructure should improve significantly.

According to a resolution on gas supply which the government promulgated in late 2000, the state would move from control of wholesale gas prices to control of gas transmission tariffs, presumably allowing commodity prices to fluctuate with market conditions. In the new regime, the Federal Energy Commission would regulate gas production, transportation, storage, delivery and sale. The FEC would develop methodologies for setting gas transportation and storage tariffs. Actual tariff setting according to these methodologies might then be delegated to regional energy commissions (RECs), which would set retail prices for gas use by residential customers and district cooperatives, as well as tariffs for distribution and retail supply services.[162] If the commodity component of the final tariff is indeed allowed to fluctuate with market conditions, the disparity between domestic and export prices should narrow and the associated problems should diminish.

160 *Ibid*., pages 118-20. MinEnergo (2001).

161 International Energy Agency (2002f), pages 136, 142.

162 Ibid., pages 121-23.

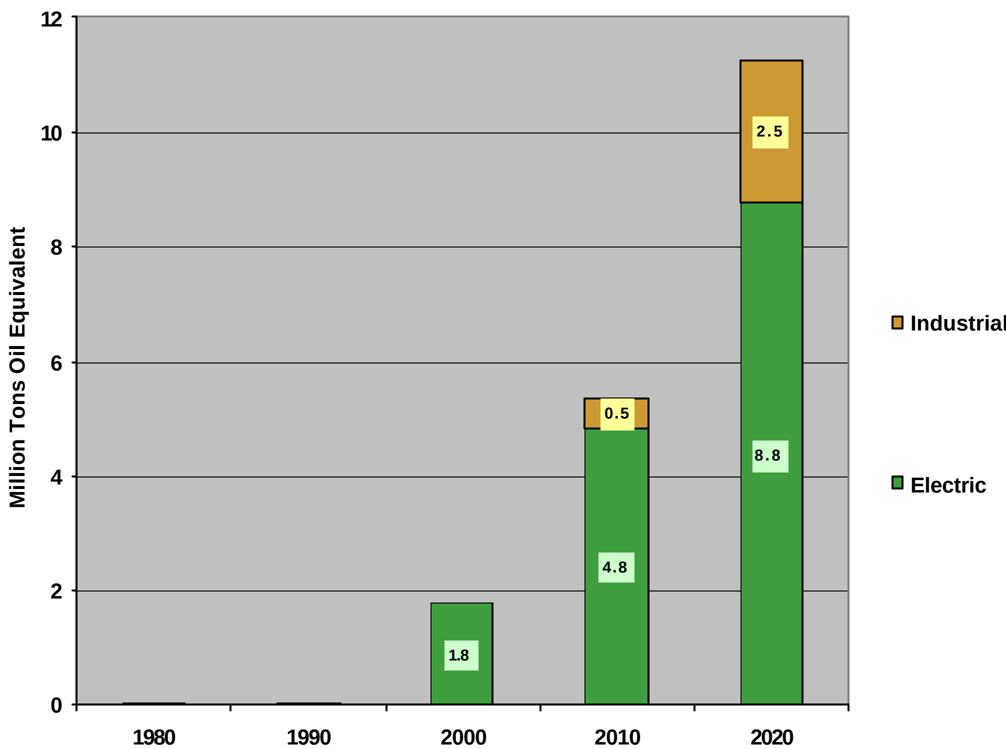
SINGAPORE

GAS MARKET SETTING[163]

Singapore relies on imports for all of its natural gas requirements.

- Gas supply and imports are projected to expand more than six-fold from 1.8 Mtoe in 2000 to 11.3 Mtoe in 2020 due to steady demand growth averaging 5.2 percent per annum from 2000 to 2010 and 3.5 percent per annum from 2010 to 2020.

Figure 61 Evolution of Natural Gas Use in Singapore, 1980-2020



Almost all of Singapore's natural gas use is devoted to electric power generation. Substantial natural gas use is anticipated in the industrial sector. Natural gas use in the commercial and residential sectors, which is not reflected in the projections above, could materialise to some extent with the expected conversion of the existing town gas network to allow distribution of natural gas.

- Use of gas for electric power generation is projected to grow rapidly, increasing nearly five-fold from 1.8 Mtoe in 2000 to 8.8 Mtoe in 2020. But the power sector's share of natural gas demand would drop sharply from 100 percent to 78 percent with the introduction of gas for industry.
- Industrial use of gas, which was nil in 2000, is projected to grow to 2.5 Mtoe by 2020, accounting for a 22 percent share of the gas market.

[163] Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Singapore's natural gas is all imported by pipeline from neighbouring Malaysia and Indonesia, though further imports through LNG terminals are foreseen. A pipeline from Malaysia, of which the portion in Singapore is owned by Senoko Power and the Malaysian portion is held by Petronas, provides gas to Senoko Power's electric generating plants. A pipeline from the West Natuna field of Indonesia provides gas to power stations and large industrial customers on Jurong Island and in the Jurong/Tuas area. The portion of the pipeline in Singapore waters is owned by SembCorp Gas, while Indonesia's portion is held by the West Natuna Transportation System, a joint venture of Pertamina, ConocoPhillips, Premier Oil and others. A third pipeline will be used by Gas Supply Pte Ltd to import gas from Sumatra. The portion in Singapore waters will be owned by PowerGas, while the Indonesian portion will be held by Perusahaan Gas Negara (PGN).[164]

Natural gas transportation in Singapore, including both high-pressure transmission pipelines and local distribution pipelines, is to be carried out solely by a regulated monopoly, PowerGas. The existing system for distribution of town gas, which serves over 500,000 customers and is available to four-fifths of Singapore's households, will be converted to allow the distribution of natural gas.

PRINCIPAL PLAYERS IN SINGAPORE'S GAS MARKET

External Producers from which Singapore Imports Gas
Pertamina (Indonesia), Petronas (Malaysia)

Owners of Transmission Pipelines for Gas Imports into Singapore
Senoko Power Ltd, SembCorp Gas Pte Ltd, PowerGas Ltd

Owner and Operator of Gas Transmission and Distribution Pipelines in Singapore
PowerGas Ltd

Gas Retailers in Singapore
Natural Gas: Gas Supply Pte Ltd, SembCorp Gas Pte Ltd, City Gas Pte Ltd
Town Gas: City Gas Pte Ltd

Source: Energy Market Authority

Natural gas is retailed to large industrial customers and power producers by SembCorp in the Jurong/Tuas Industrial Area and on Jurong Island. Gas Supply Pte Ltd and City Gas Pte Ltd will also be supplying natural gas. Town gas manufactured from naphtha is retailed by City Gas, and bottled liquefied petroleum gas (LPG) is marketed by oil companies.

UNBUNDLING AND THIRD PARTY ACCESS

Under the Gas Act of 2001, transportation and other functions in Singapore's gas market are in principle to be unbundled at the ownership level. PowerGas, as gas transporter, is specifically barred from competitive portions of the industry, including gas importation, trading and retailing. Thus, PowerGas divested the City Gas and Gas Supply retail companies in January 2002. Once conversion of the town gas system is complete, the market will be open to these and other competing retailers, who will be prohibited from engaging in the business of gas transportation. Yet at least for now, some integration of functions in the gas market remains. For example,

164 Energy Market Authority (2002), (2003b). Trade Partners UK (2002).

SembCorp Gas both transports and retails gas. In addition, Malaysia's Petronas and Indonesia's Pertamina are each involved in both production and transportation of gas for Singapore.[165]

Still, the Gas Act clearly provides for non-discriminatory access to transportation services. A gas transporter shall "comply, so far as it is economical to do so, with any reasonable request to connect" with the pipeline network and "convey gas" to "any premises," the Act declares. "It shall also be the duty of a gas transporter to avoid undue preference or undue discrimination in the terms on which it undertakes the conveyance of gas" or "in the connection of premises." Further, the Act provides that "in establishing prices…a gas transporter shall not show undue preference or exercise undue discrimination as between shippers similarly situated." If a person is not able to negotiate access, there are rights of appeal to the Energy Market Authority (EMA). These provisions for non-discriminatory access to transportation facilities apply not only to pipelines and associated processing facilities, but also to such LNG facilities as the Authority may designate.[166]

MARKET MODEL AND COMPETITION

Singapore's gas market combines elements of the wholesale competition and customer choice models, but actual competition appears quite limited. Smaller customers have had little access to natural gas but are able to choose between town gas from City Gas and liquefied petroleum gas (LPG) from oil companies. Senoko Power, a large electric power producer, imports gas directly, but it does so under a long-term take-or-pay contract with just a single foreign producer (a 15-year contract expiring in 2007). SembCorp Gas, the predominant retailer of natural gas to Tuas Power and other large customers in the Jurong/Tuas industrial area and on Jurong Island, effectively serves as a single buyer for such customers and also imports gas under a long-term take-or-pay contract with a single foreign producer (a 22-year contract running from 2001 through 2023). There are just two competing foreign producers, each of which functions as a vertically integrated monopoly. And since current import contracts with both producers are on a long-term, take-or-pay basis, there would appear to be limited scope for competition from other producers for the time being.[167]

However, as Singapore's gas market expands, it may allow greater competition and customer choice. As gas demand continues to grow, the market should accommodate imports from additional producers. Open access to pipelines and LNG terminals, as provided for in the Gas Act, should allow effective competition for large and small customers alike. Gas Supply Pte Ltd should make more gas available to small consumers through its contract with Indonesia. With most of the populace served by the gas distribution network, several competing retailers may well emerge.

Singapore's gas and power markets have become vertically integrated to a significant degree. The share of gas in power production has been rising, competition in the power market is limited, and some companies own assets in both gas and electricity markets. Just a fifth of the economy's electricity was generated from gas in 1998, but the gas share grew in 2001 with the opening of new gas pipeline links with Indonesia and should grow further as gas imports increase.[168] In 2000, about 79 percent of all electric generating capacity was held by Singapore Power through two subsidiaries, Power Senoko and Power Seraya, while another 17 percent was held by Tuas Power.[169] Although Singapore Power divested its generating assets in 2001, Power Senoko retains a large share of generating capacity and obtains its own gas through a long-term contract with Malaysia. Both Tuas Power and a cogeneration plant owned by SembCorp Gas (which produces both industrial steam and power) obtain gas supplied by SembCorp Gas under a long-term contract with Indonesia. On the purchasing side, with gas volumes fixed by contract and growing reliance on gas-fired turbines,

---

165 Energy Market Authority (2003a), (2003b).

166 Republic of Singapore (2001), sections 9, 21, 25, 38. There are no LNG facilities at present.

167 Energy Market Authority (2003a). Trade Partners UK (2002).

168 APEC Energy Working Group (2002), pages 230-31. APERC (2002b), page 104. In 1998, 1,132 ktoe of gas and 4,535 ktoe of petroleum were used for power generation, totalling 5,687 ktoe of which the gas share was 20 percent.

169 Trade Partners UK (2002).

the power companies have little flexibility to shift to other fuels if gas prices rise under the contract formulas. On the customer side, with competition limited, the power companies may still have some market power to pass on resulting cost increases to their customers.

However, the vertical integration of gas and power markets may soon weaken due to gas market reforms and growing competition in the power sector. Four different companies compete to generate power, and large customers have a choice of power suppliers. More power companies may enter the market over time, and small customers may be given a choice of power suppliers. The electric transmission and distribution systems are owned by PowerGrid Ltd, while the wholesale power market is run by the Energy Market Company, a joint venture of EMA and M-Co of New Zealand.[170] Since PowerGas has no power business, it should be willing to transport gas to all competing electricity generators on a non-discriminatory basis. Hence, the benefits of price competition in the gas sector should be passed on to generators in the power sector and thence to electricity consumers. On the other hand, a failure to diversify gas supplies could keep the gas and power sectors integrated in that if competing generators must obtain gas from similar sources, the effective scope for competition among them will remain limited to capital and operating costs.

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Singapore's gas transmission network is designed to transport natural gas from neighbouring economies. There is a 730 km pipeline for imports from Malaysia, through which Senoko Power imports 155 million cubic feet (4.4 Mcm) per day from Petronas. There is also a 640 km subsea pipeline link with Indonesia, with a capacity of 700 Mcf (19.8 Mcm) per day, through which SembCorp Gas imports 325 Mcf (9.2 Mcm) per day from Pertamina. A new subsea link with Indonesia will deliver 350 Mcf (9.9 Mcm) per day by 2009 under a 20-year contract between Pertamina and Gas Supply. There are also 70 km of domestic town gas transmission pipeline.[171]

The gas distribution network in Singapore is well developed, with 2,600 km of local town gas pipelines that are being converted to accommodate natural gas. About 80 percent of households have access to the network, and the Gas Act requires connection of all parties that desire access on reasonable terms. For customers within 20 metres of a distribution main, the transporter is to provide and lay the pipe required for the connection; other customers must provide and lay the pipe themselves. Costs of connection may only be recovered from new customers to the extent that they have not been previously recovered from others.[172]

INFRASTRUCTURE INVESTMENT INCENTIVES

Singapore's incentives for investment in transmission and distribution infrastructure appear to be adequate, in view of the infrastructure that has been built to date. In the restructured gas industry, the Energy Market Authority will regulate transmission and distribution charges of the monopoly gas transporter, PowerGas. EMA will presumably allow a market-based rate of return on portions of the PowerGas network expansion plan that it approves as being needed by gas users.

---

170 APERC (2002b), pages 101-3. Energy Market Authority (2003a). On 1 April 2001, Singapore Power divested two generating companies, PowerSenoko and PowerSeraya, to Temasek Holdings, while retaining both its Power Supply Ltd arm, which provides market support services like billing and metering, and its Power Grid arm, which owns the electric transmission and distribution network. A third generating company, Tuas Power, operates the 1,935 MW Tuas power station, while a fourth, SembCorp Cogen, operates a 650 MW cogeneration plant. Large consumers can buy electricity from any of six competing retailers. Small consumers will continue to be supplied at regulated tariffs by Power Supply's successor company, SP Services, until they become eligible to choose among retail suppliers. With the competitive businesses of generation and retail power supply separated from the monopoly functions of power transmission and distribution, non-discriminatory access to the electric power grid is assured.

171 Energy Market Authority (2003a), EIA (2002e).

172 Republic of Singapore (2001), section 22.

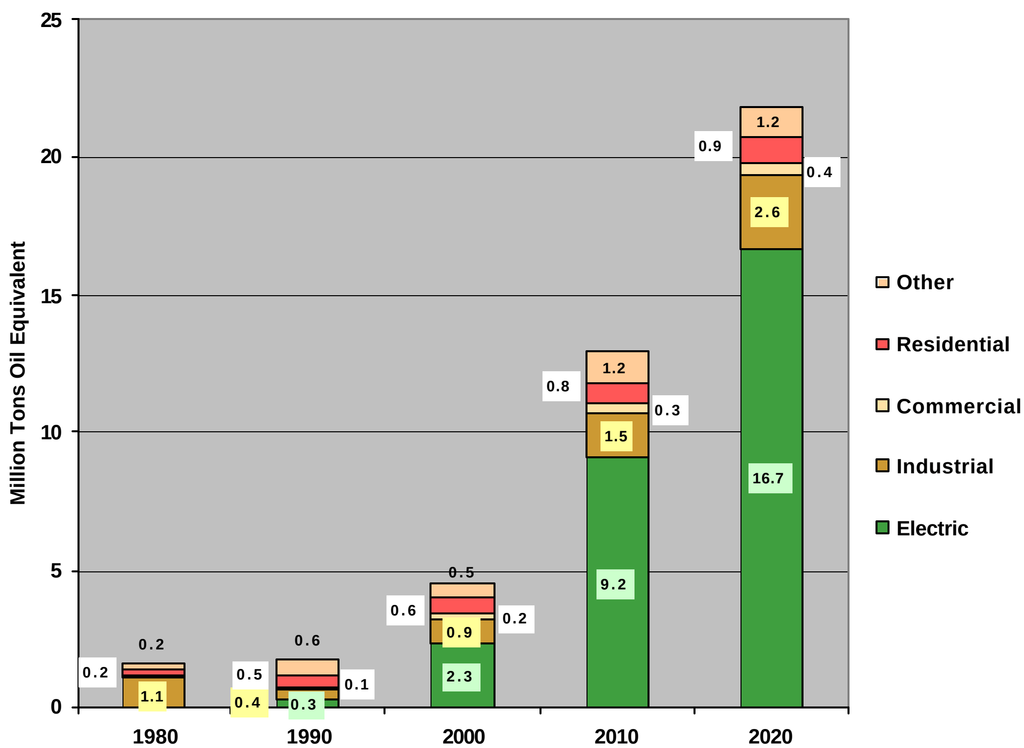
CHINESE TAIPEI

GAS MARKET SETTING[173]

Chinese Taipei imports most of its gas, though it produces a small amount indigenously.

- Gas production, which was small in 2000, is projected to reach roughly 1.2 Mtoe in 2020, at which time it would satisfy about 5 percent of domestic gas requirements.
- Imports of gas, which currently come from Indonesia and Malaysia, are projected to more than quadruple from 4.5 Mtoe in 2000 to 20.7 Mtoe in 2020.
- Primary supply of gas to the economy is projected to increase nearly five-fold from 4.5 Mtoe in 2000 to 21.9 Mtoe in 2020, owing to very rapid growth of 11.1 percent per annum from 2000 to 2010 declining to 5.4 percent yearly from 2010 to 2020.

Figure 62 Evolution of Natural Gas Use in Chinese Taipei, 1980-2020



Chinese Taipei's natural gas use is fairly diversified but becoming less so over time. More than half of all gas demand emanates from the electric power sector, and the share is trending upward rapidly. Roughly one-fifth of demand occurs in the industrial sector, while another fifth is divided between the commercial and residential sectors, but the relative importance of these sectors is fast declining as the power sector market for gas expands.

173 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

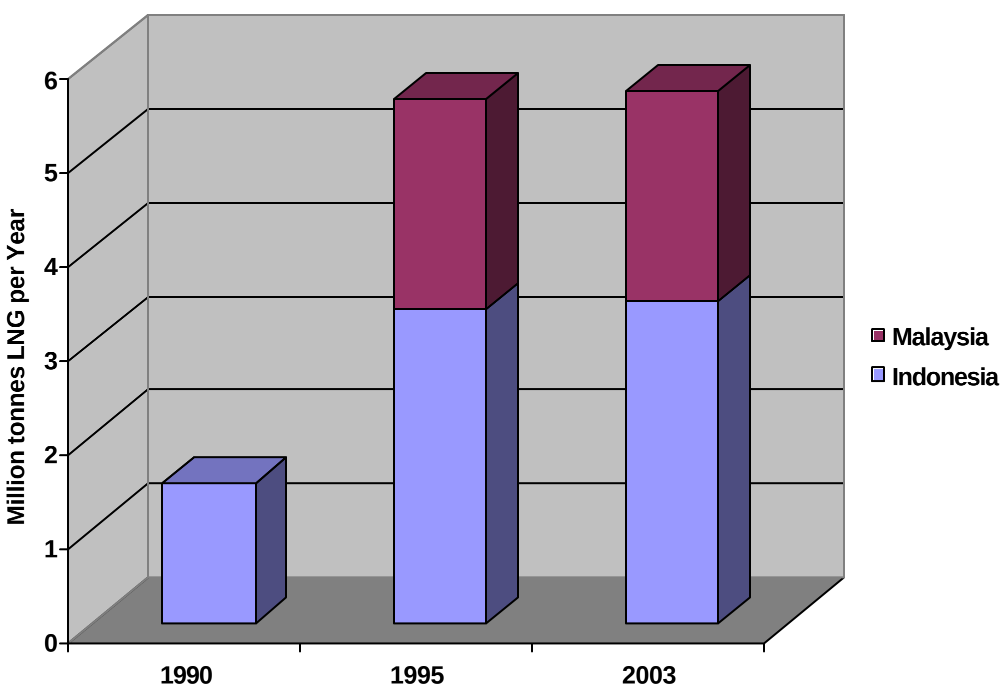
- Rapid growth is anticipated in use of gas for electric power generation, with demand increasing seven-fold from 2.3 Mtoe in 2000 to 16.7 Mtoe in 2020, so that the power sector's share of gas use jumps by half, from 51 percent to 76 percent.
- Industrial gas use is also projected to grow substantially in absolute terms, nearly tripling from 0.9 Mtoe in 2000 to 2.6 Mtoe in 2020, but its share of overall gas demand is projected to fall sharply from 20 percent to 12 percent.
- Commercial and residential gas use will likely grow more modestly, with the commercial share of gas demand projected to fall by more than half from 5 percent in 2000 to 2 percent in 2020 and the residential share to fall by more than a factor of three from 14 percent to 4 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Chinese Taipei has modest indigenous gas production, some of which comes from wells on land and some of which occurs offshore. All domestic gas production is controlled by the publicly-owned Chinese Petroleum Corporation (CPC). Most of the economy's gas is imported through LNG terminals, which are a key element of gas transportation infrastructure along with gas pipelines. All gas imports come from Indonesia and Malaysia, with a fairly even split between the two.[174] Imports began in 1990 with the completion of LNG facilities at Yung-an and the signature of a 20-year contract with Indonesia for 1.5 million tons of LNG (about 1.9 Mtoe) per year. With expansion of these LNG facilities, import capacity reached 4.5 million tons (5.8 Mtoe) in the mid-1990s and 7.87 million tons (10.17 Mtoe) in 2002, substantially in excess of current import levels.[175]

Figure 63 Evolution of Chinese Taipei's LNG Sources under Long-Term Contracts



Source: Cedigaz

[174] Cedigaz (1999), pages 71-2.

[175] Wang (1994), page 295. APERC (2002c), page 36.

Transmission of gas in Chinese Taipei, like production, is controlled by the Chinese Petroleum Corporation. CPC supplies gas to electricity generators and large industrial firms directly through its LNG facilities and high-pressure pipeline grid. Distribution of gas to smaller users is performed by 26 different companies, one of which is operated by CPC. Each distribution company has its own franchised distribution area, to which gas is delivered through CPC's transmission grid.

PRINCIPAL PLAYERS IN CHINESE TAIPEI'S GAS MARKET

External Producers from which Chinese Taipei Imports Gas
Pertamina (Indonesia), Petronas (Malaysia)

Gas Producers in Chinese Taipei
Chinese Petroleum Corporation (CPC)

Owner and Operator of LNG Terminals and Gas Transmission Pipelines in Chinese Taipei
Chinese Petroleum Corporation (CPC)

Owners and Operators of Gas Distribution Pipelines in Chinese Taipei
The Great Taipei Gas, Hsin Hsin Gas, Hsin Chung Gas, Shin Hai Gas, Hsin Chu Gas, Chinese Petroleum Corporation (Hsin-Chu and Miao Li District Office), 20 other distribution companies

Sources: Energy Commission, Ministry of Economic Affairs, Wang

As Chinese Taipei's gas requirements grow, there may be opportunities to diversify the sources from which gas is imported and to obtain gas from competing producers. While CPC operates all LNG facilities today, a competing company will build a second LNG receiving terminal which will start supplying gas in 2008 and reach a yearly capacity of 1.68 Mt (2.17 Mtoe) by 2011. [176]

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in Chinese Taipei are substantially unbundled. The Chinese Petroleum Corporation is an integrated producer, transporter and distributor of gas. However, CPC's share of production and distribution is small; in 2001, it accounted for just 11 percent of production and 7 percent of distribution by volume. While CPC dominates transport, production comes mainly from abroad and most distribution is performed by 25 other companies.

There is currently no third-party access to gas transportation facilities in Chinese Taipei. CPC controls all domestic production and imports, so it provides access to transmission pipelines and LNG facilities only to itself. Local utilities in turn, provide access to distribution pipelines only for gas supplied by CPC. Even if competing LNG facilities are built, there is nothing in the current system that would require CPC to give competing importers access to its pipelines.

MARKET MODEL AND COMPETITION

The gas market in Chinese Taipei would seem in principle to resemble the wholesale competition model, though in practice there is little competition. In theory, there could be substantial wholesale competition, since most of the economy's gas is imported and CPC can purchase gas from the least-cost foreign producer. But in practice, CPC obtains all of its imports, which constitute roughly nine-tenths of overall domestic supply, from just two outside economies. Those two economies, Indonesia and Malaysia, operate their own gas markets as vertically integrated monopolies. Since import contracts with both economies are on a long-term, take-or-pay basis, there seems to be limited scope for competition from other producers in the near future.

176 Energy Commission (2003).

But looking forward, the number of competing gas producers may expand, and wholesale competition may become more of an operative reality. Retail competition might also evolve, at least for large industrial firms and electricity generators with direct access to the transmission grid. Private enterprises are expected to enter the gas import and wholesale businesses in the foreseeable future, and the government is preparing a new natural gas business law to deal with this prospect. To promote competition, negotiated third party access to transmission pipelines may be allowed.

Chinese Taipei's gas and electricity markets are vertically integrated to a significant degree, even though there is no cross-ownership between the two markets and the wholesale power market is quite competitive. Natural gas accounted for 13 percent of electricity generated in Chinese Taipei in 2000.[177] While most electric generating capacity is owned and operated by the Taiwan Power Company (Taipower), independent power producers (IPPs) that sell to Taipower in the wholesale electricity market owned 15 percent of generating capacity by the end of 2002.[178] However, since all power producers must obtain gas through CPC, their gas costs are similar and the scope for competition among their gas-fired power plants is limited to capital and operating costs. Moreover, with the large share of gas-fired generating capacity, power producers have limited flexibility to shift to other fuels. Thus, CPC has considerable market power to pass on the costs of inefficiencies that might arise in gas procurement, shipping, and processing, as well as in the construction and operation of LNG facilities and pipelines, in higher gas prices to power producers. Finally, as the sole supplier of electricity at retail, Taipower can pass on to electricity customers the higher costs of generating or buying electricity that may result from higher gas prices.

Over time, if there come to be more competing gas producers with a larger share of a growing gas market, and if new gas retailers also appear, the integration of gas and electricity markets could weaken. The government is considering a new electricity law that would allow IPPs to offer electricity to any utility (not just Taipower) in the wholesale power market or to sell directly to customers in the retail power market and would gradually allow consumers to buy electricity from any supplier.[179] With such a law enhancing competition among electricity generators, the benefits of greater price competition in the gas sector would likely be passed on to electricity users.

PRICE TRENDS

Natural gas prices in Chinese Taipei declined quite steadily in all end-use sectors during the 1990s. For industrial customers, the real price in 2000 US$ declined by 23 percent from US$387 per tonne of oil equivalent in 1990 to US$298 per toe in 2000. The real price for electric power producers dropped 30 percent from US$352 to US$246 per toe over the decade. Gas prices for households meanwhile declined by 27 percent in real terms from US$543 to US$398 per toe.[180] These price trends would appear mainly to reflect a softening of international LNG prices in accordance with the long-term import contracts that CPC has negotiated.

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Chinese Taipei's gas transportation infrastructure appears to be keeping pace with rapidly growing demand. The LNG terminal capacity available at the end of 2002, some 10.2 Mtoe per

177 APEC Energy Working Group (2002), pages 240-41. Of 22,218 ktoe of public electricity production and industrial electricity autoproduction, 2,827 ktoe or 13 percent was fuelled by gas. Considering the 20,035 ktoe of public electricity production only, 2,766 ktoe or 14 percent came from gas.

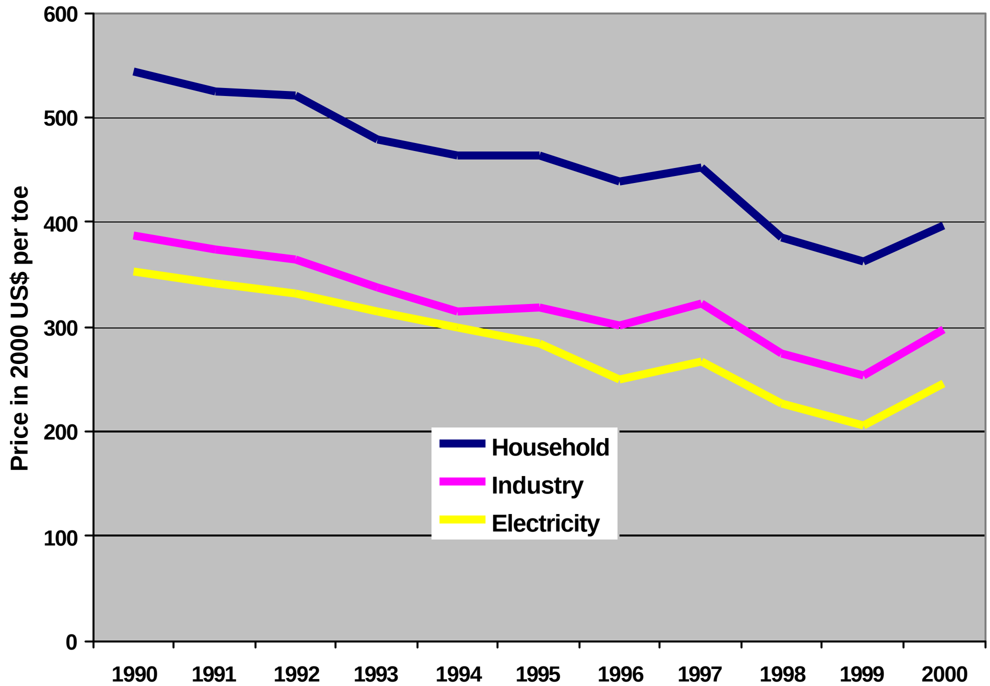
178 Taiwan Power Company (2002), pages 8-9. Net summer peaking capability in 2002 is reported at 31,449 MW. IPP capacity in mid-2002 included 1,800 MW at Mialiao (3x600 MW), 900 MW at Everpower (2x450 MW), 1,297 MW at Hoping (2x648.5 MW), 600 MW at Hsintao and 9 MW at Wusantou, totalling 4,606 MW or 15 percent of the capability.

179 APERC (2002b), page 107.

180 International Energy Agency (2002b), page 469-71. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

annum, was already adequate to meet the gas demand that IEEJ projects for 2008 (interpolating between projections for 2000 and 2010). The second LNG terminal, to begin operation in 2008, would bring total capacity to 12.3 Mtoe per annum by 2011, just shy of projected needs that year.

Figure 64 Natural Gas Prices in Chinese Taipei, 1990-2000



Source: International Energy Agency, US Department of Commerce

The gas distribution network in Chinese Taipei is well developed. The service areas of the 26 distribution companies cover almost all the island except for a few sparsely populated rural areas (the eastern districts of Yilan, Hualien and Taitung) to which CPC has not laid pipelines.

INFRASTRUCTURE INVESTMENT INCENTIVES

Investment incentives for enhancement of gas transmission and distribution pipelines appear to be reasonable and adequate, to judge by the gradual expansion of gas transportation grids. For any planned investment in the gas transmission network, CPC is required to submit an evaluation report for review by the Ministry of Economic Affairs. The evaluation includes a cost-benefit analysis, as well as estimates of future cash flows, capital costs, and internal rate of return.

Investments in distribution infrastructure are recovered through a standard rate of return on costs incurred. Local distribution companies submit rate adjustment plans to the Ministry of Economic Affairs and to a local municipal or county government for approval. A standard rate of return of not less than 6 percent per annum is allowed, with a risk premium of up to 3.7 percent per annum added to the basic rate charged for borrowing money from commercial banks.

LNG facilities have so far been built entirely by CPC, under procedures imposed by the Ministry of Economic Affairs for the regulation of public enterprises. With respect to future LNG facilities, to be built by private companies, it is anticipated that investments will be market-based. The rate of return on privately built LNG facilities will not be regulated, so the incentives for building them should be in proportion to the tightness of gas supplies as measured by price.[181]

181 Ministry of Economic Affairs (2003).

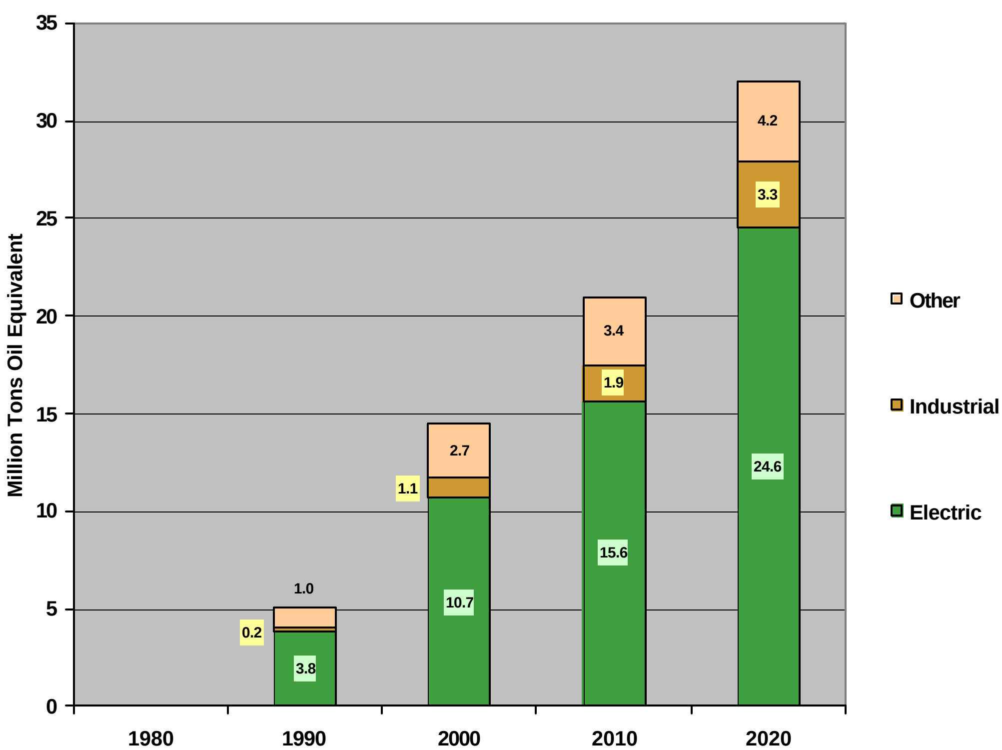
THAILAND

GAS MARKET SETTING[182]

Thailand both produces and consumes a substantial amount of gas, with production not entirely sufficient to meet domestic demand.

- Gas production is projected to more than double from 11.6 Mtoe in 2000 to 24.1 Mtoe in 2020, but the gap between demand and production is projected to widen slightly from 24 percent to 33 percent of production over the same period.
- Net imports of gas, from Myanmar and elsewhere in Asia, are projected to increase roughly from 2 Mtoe in 2000 to 8 Mtoe in 2020.
- Primary supply of gas to the domestic economy is projected to more than double from about 14.5 Mtoe in 2000 to 32.0 Mtoe in 2020, with annual growth rates averaging 3.8 percent from 2000 to 2010 and 4.4 percent from 2010 to 2020.

Figure 65 Evolution of Natural Gas Use in Thailand, 1990-2020



Very nearly all of Thailand's natural gas use is devoted to energy transformation and industry. About three-quarters of the economy's gas is used for electric power generation. The remainder of gas use is mainly divided between natural gas processing and assorted industrial applications.

182 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Use of gas for electric power generation is projected to more than double from 10.7 Mtoe in 2000 to 24.6 Mtoe in 2000, so that its share of overall gas demand increases slightly from 74 percent to 77 percent.
- Industrial use of gas is expected to triple from 1.1 Mtoe in 2000 to 3.3 Mtoe in 2020, while its market share grows from 7 percent to 10 percent.
- "Other" gas use, primarily for natural gas processing, is projected to grow from 2.7 Mtoe in 2000 to 4.2 Mtoe in 2020, but its share of the gas market is projected to fall from 19 percent to 13 percent due to much faster growth in other sectors.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Thailand has several competing gas producers. There are two dominant producers, three other significant producers, and a number of minor producers. One of the dominant producers is PTT-Exploration and Production, a subsidiary of the state-owned Petroleum Authority of Thailand (PTT), which accounted for 39 percent of domestic gas output in 2000. The other dominant producer is Unocal, which accounted for 55 percent of production. Other producers including Total, Thai Shell Exploration and Production (Royal Dutch Shell), and Esso Exploration and Production (Exxon Mobil) accounted for the remaining 6 percent of domestic gas output.[183] All gas in Thailand is transported by pipeline; there are no LNG facilities existing or planned.

Transportation and distribution of gas in Thailand is controlled by the Petroleum Authority of Thailand (PTT), which is a publicly-owned corporation. After transporting its own gas production, PTT transports the output of competing gas producers on a negotiated basis.[184]

PRINCIPAL PLAYERS IN THAILAND'S GAS MARKET

External Producers from which Thailand Imports Gas
Myanma Oil and Gas Enterprise (MOGE)(Myanmar)

Gas Producers in Thailand
Petroleum Authority of Thailand – Exploration and Production (PTTEP)
Unocal, Total, Thai Shell Exploration and Production
Esso Exploration and Production, several smaller producers

Owner and Operator of Gas Transmission Pipelines in Thailand
Petroleum Authority of Thailand (PTT)

Owner and Operator of Gas Distribution Pipelines in Thailand
Petroleum Authority of Thailand (PTT)

Source: Energy Policy and Planning Office

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in Thailand are substantially unbundled. The Petroleum Authority of Thailand (PTT) is an integrated producer, transporter and distributor of gas. However, there are

183 Energy Policy and Planning Office (2002).

184 *Ibid.* US Department of Energy, Office of Fossil Energy (2003).

several competing gas producers without pipeline assets. Third-party access to gas transportation and distribution grids is provided on a negotiated basis. PTT first uses pipeline capacity to ship its own gas, then allows competing producers to use remaining pipeline capacity to ship their gas.[185]

Looking forward, the government intends for PTT to serve as a common carrier, with third-party access to its pipelines provided on a regulated basis.[186] As of 2006, an independent regulatory agency is to be charged with ensuring non-discriminatory access to pipelines.[187] If the government's intentions are realised, then as the gas market continues to grow, an increasing share of gas demand should be satisfied on a non-discriminatory basis by competing gas producers.

MARKET MODEL AND COMPETITION

Thailand's gas market would seem to fit most closely the wholesale competition model, although elements of vertically integrated monopoly remain. PTT serves as a single gas transportation and distribution company for the entire economy and also produces a significant share of the economy's gas. PTT's transportation arm gives preference to its production arm in purchasing gas at wholesale; in this sense, PTT behaves like a vertically-integrated monopoly. But there is also substantial wholesale competition, as PTT buys and transports gas from several competing producers in addition to itself; its own production meets only about two-fifths of total demand. As the share of imports in Thailand's gas supply increases, so may the number of competing producers that supply the market. On the other hand, there is no retail competition, since all gas customers must obtain their gas from PTT.

Thailand's gas and electricity markets are vertically integrated to a great extent, even though there is no cross-ownership between the two markets and the wholesale power market is quite competitive. About two-thirds of the economy's electricity is generated from gas by various players including the Electricity Generating Authority of Thailand (EGAT), the Electricity Generating Company (EGCO), independent power producers (IPPs) and small power producers (SPPs). Together, the IPPs and SPPs owned 36 percent of all generating capacity as of the end of 2002. But since all power industry competitors must buy gas from PTT, their gas prices are similar and the scope for competition among their gas-fired plants is limited to capital and non-fuel operating costs.[188] Moreover, with the very high share of gas-fired generating capacity, power producers have little flexibility to shift to other fuels. As a result, PTT has substantial market power to pass on costs of inefficiencies that may arise in gas procurement, shipping, processing and transportation by charging power producers higher gas prices.

Looking forward, the government foresees an expansion of business-to-business competition in the gas market. In this vision, independent power producers, industrial firms, small commercial businesses and transportation providers would be able to choose among competing gas suppliers. If such a vision could be realised, in view of the substantial competition that exists in the power market, lower prices from gas market competition would likely be passed on to electricity users.

PRICE TRENDS

Real natural gas prices in Thailand declined markedly in the mid-1990s but have been on a modest upward trend since then. For industrial customers, the real price in 2000 US$ declined by nearly a third from US$200 per tonne of oil equivalent in 1995 to US$137 per toe in 1998. For the Electricity Generation Authority of Thailand (EGAT), the real price declined by almost a fifth from

185 Energy Policy and Planning Office (2002).

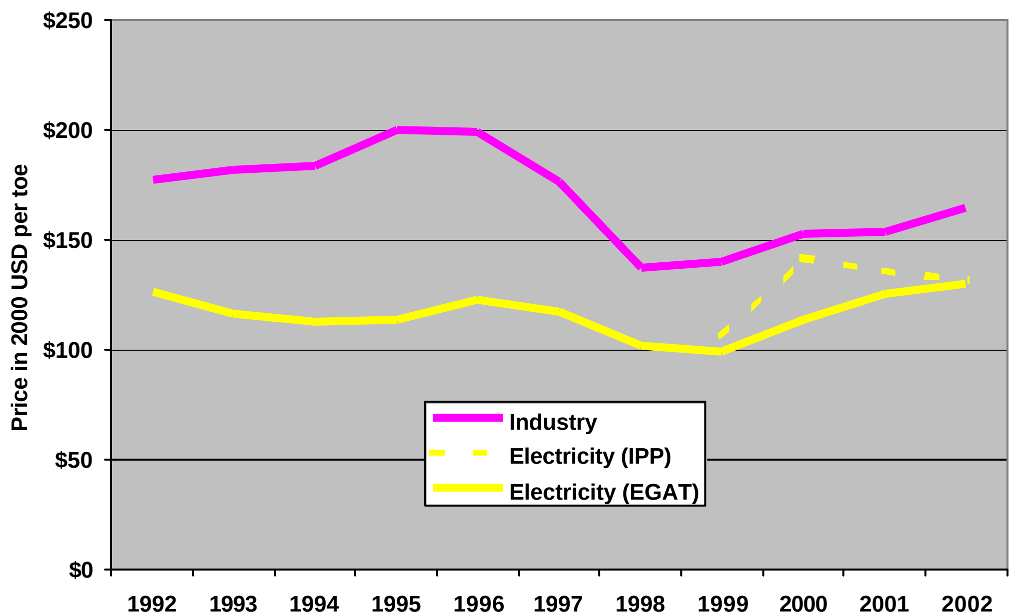
186 National Economic and Social Development Board (1996), Part I (Energy Development), section 3.3.1(2).

187 Energy Policy and Planning Office (2002).

188 *Ibid.* PTT has been selling gas to EGAT and IPPs at cost plus margins of 1 percent to 1.5 percent while charging small power producers a margin of 9 percent. However, gas prices charged to all power producers are to be equalised as of 2003 when an electric power pool is scheduled to be introduced in Thailand. Of the 24,479 megawatts of generating capacity in service in December 2002, EGAT held 15,000 MW (61 percent), IPPs owned 7,071 MW (29 percent), SPPs owned 1,768 MW (7 percent), and 640 MW (3 percent) was imported.

US$122 to US$99 per toe between 1996 and 1999. However, the price declines seem to have been mainly due to devaluation of the baht, which slid in value by 39 percent against the US dollar between 1996 and 1998. Absent that devaluation, industrial gas prices would have increased slightly and electric utility gas prices would have increased markedly in the late 1990s. Gas prices for independent power producers were initially set several percent higher than those for EGAT, but the prices for IPPs and EGAT were approximately equalised by 2002.[189]

Figure 66 Natural Gas Prices in Thailand, 1992-2002



Sources: Energy Policy and Planning Office (EPPO) and US Department of Commerce

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

As of the end of 2002, Thailand had some 2,337 km of gas transmission pipelines that connect major gas fields to major consumption centres, as well as 277 km of gas distribution pipelines.[190] The gas distribution network does not extend to small residential and commercial customers, and there are no plans to extend the network to such customers. Because of the tropical climate, there is little or no prospective demand by households and small businesses to use natural gas for heating. There is also little prospective natural gas demand for cooking, which is primarily performed today with liquefied petroleum gas (LPG).[191]

INFRASTRUCTURE INVESTMENT INCENTIVES

Incentives for investment in Thailand's gas transportation network appear to be very strong. The regulated rate of return (ROR) on gas pipelines is set by the Energy Policy and Planning Office

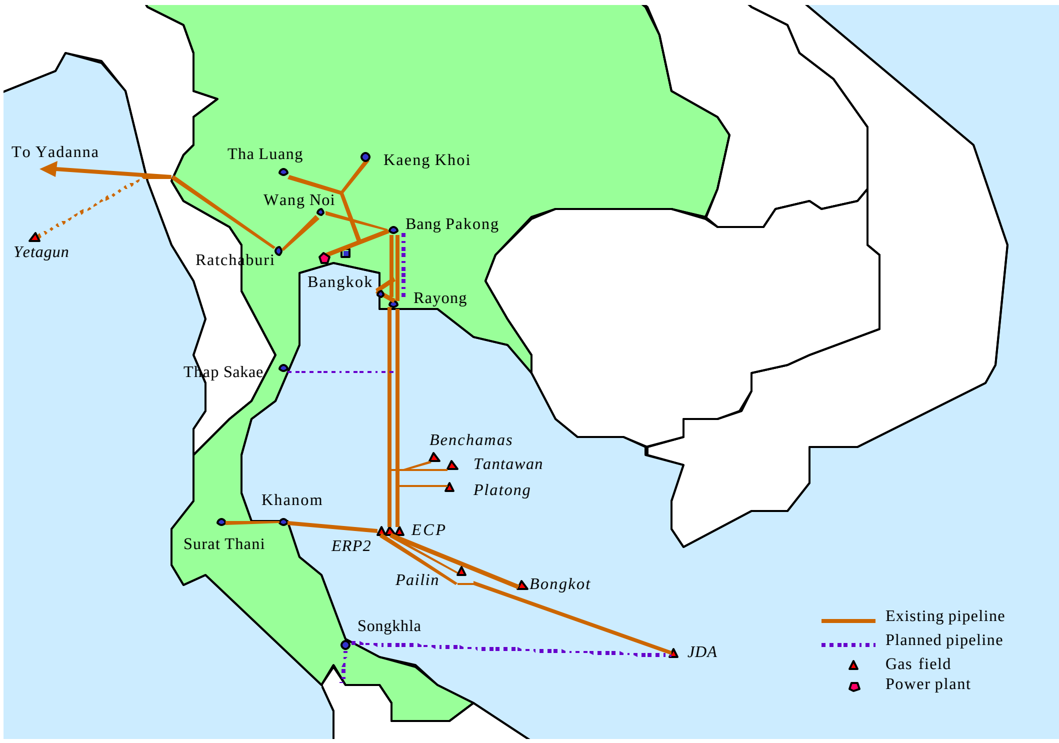
189 Energy Policy and Planning Office (2003). Nominal prices in US$ per toe calculated by multiplying prices in baht per million Btu by 39.68 MBtu per toe and dividing the product by prevailing exchange rates of baht per US$ from the Bank of Thailand (2003). Real prices in US$ calculated by dividing nominal prices in US$ by implicit GDP deflators from US Department of Commerce.

190 PTT (2003). PTT map indicates 1,372 km of offshore transmission lines and 965 km of onshore transmission lines.

191 Energy Policy and Planning Office (2002).

(EPPO) in the Ministry of Energy. EPPO generally allows an ROR of 18 percent on approved gas pipeline projects. This is usually well above the risk-adjusted interest rate for borrowing capital on the marketplace, so that building new or enhanced gas transportation links can be quite profitable.[192]

Figure 67 Existing and Planned Gas Pipeline Infrastructure in Thailand



Sources: APERC (2000c), Petroleum Authority of Thailand (2003).

192 *Ibid.*

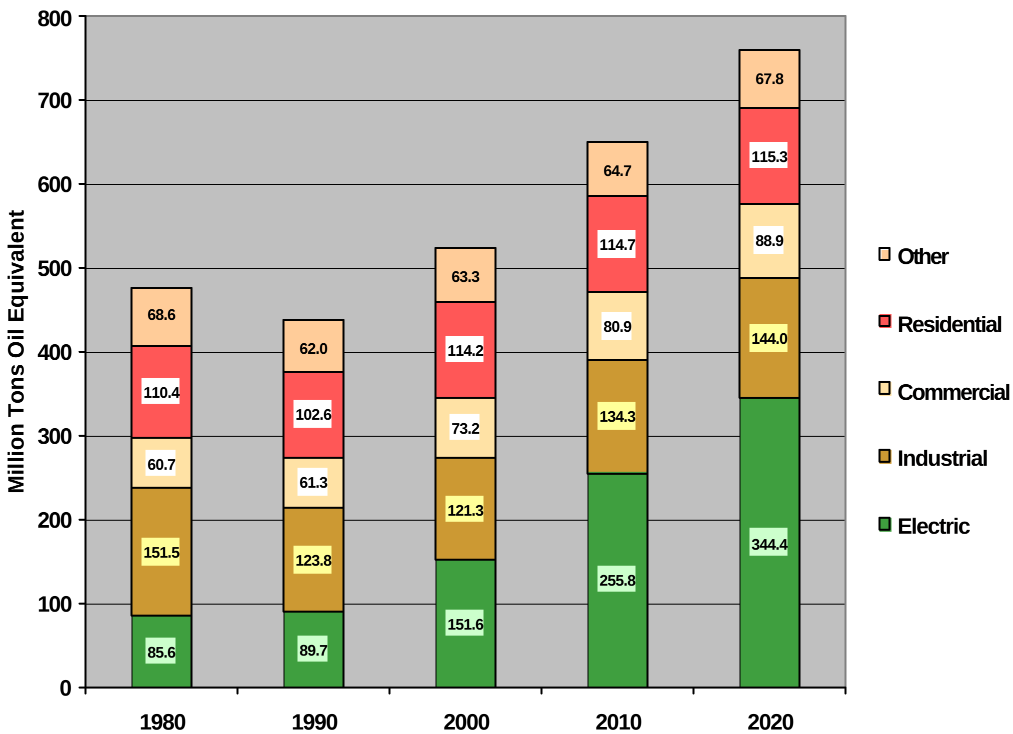
UNITED STATES

GAS MARKET SETTING[193]

The United States is the world's largest gas consumer and second-largest gas producer, with production not entirely sufficient to meet domestic demand.

- Gas production is projected to increase very substantially from 445 Mtoe in 2000 to 691 Mtoe in 2020, as a result of which the gap between demand and production is projected to narrow from 18 percent to 10 percent of production.
- Net imports of gas, with major inflows from Canada and less substantial exports to Mexico, are currently the largest for any APEC economy but are projected to decline roughly from 79 Mtoe in 2000 to 69 Mtoe in 2020.
- Primary supply of gas to the domestic economy is projected to grow markedly in absolute terms from 524 Mtoe in 2000 to 760 Mtoe, despite modest annual growth rates averaging 2.2 percent from 2000 to 2010 and 1.6 percent from 2010 to 2020.

Figure 68 Evolution of Natural Gas Use in the United States, 1980-2020



Natural gas use in the United States is well diversified, with about a third of gas demand in the commercial and residential sectors, nearly a quarter used in the industrial sector, and about two-fifths consumed in production of oil, gas and electricity.

- The fastest growth in gas use is projected to occur in the electric power sector, with demand more than doubling from 152 Mtoe in 2000 to 344 Mtoe in 2020, boosting the sector's share of gas use by half, from 29 percent to 45 percent.

193 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were compiled by the International Energy Agency (IEA). Projections for 2000, 2010 and 2020 were made by APERC.

- Industrial gas use is projected to grow very slowly, from 121 Mtoe in 2000 to 144 Mtoe in 2020, with its share of total gas demand declining from 23 to 19 percent.
- Commercial gas use is also projected to grow very slowly, from 73.2 Mtoe in 2000 to 88.9 Mtoe in 2020, with its share declining from 14 percent to 12 percent.
- Residential gas use is expected to stagnate near current levels, so that its share of total gas demand declines sharply from 22 to 15 percent between 2000 and 2020.[194]

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

There are many competing gas producers in the United States, as shown in the table below. They provide gas through the transmission network to local distribution companies, retail marketers, and large end-users. Numerous retail gas marketers compete for the business of end-use customers in the growing number of states that allow supplier choice. Most end-users retain the option to purchase gas from their local distribution company as well. Moreover, a great number of electric utilities and large industrial firms obtain gas for their own use directly from producers, without a marketer as intermediary, making their own arrangements for gas transmission to do so.[195]

The gas transmission function is shared by a fair number of different pipeline companies in each region.[196] For the most part, economic regulation of transmission pipelines is performed by the Federal Energy Regulatory Commission (FERC), which has jurisdiction over all pipelines that are involved in interstate commerce. In Texas and California, where many pipelines are entirely within the state due to its large geographic expanse, there is also substantial regulation by the Texas Railroad Commission and the California Energy Commission, respectively. Gas distribution grids are regulated primarily by the states. However, a substantial number of rural and municipal gas grids are managed by local or city governments and are thus largely exempted from state rate regulation.

With respect to gas transmission, there are significant players not only in the United States but also in Canada. Because a substantial portion of gas supply is imported from Canada, there are major pipelines linking Canadian producers with markets in the West and Midwest. There is also a major pipeline through which gas is transported from western Canada via the Midwest to the Canadian province of Ontario. Since gas markets in the US and Canada are closely linked, changes in gas supply or price in either economy are likely to result in similar changes across the border.

UNBUNDLING AND THIRD PARTY ACCESS

In the US gas market, transmission is entirely unbundled from production and retail supply. All interstate natural gas pipelines were required to unbundle their supply and transportation functions in 1992, pursuant to Order 636 of the Federal Energy Regulatory Commission. Pipelines may not act as gas merchants, except through functionally separate affiliates. In addition, the transmission function, performed by pipeline companies, is effectively unbundled from the distribution function, performed by local distribution companies.

FERC Order 436, issued in 1985, requires regulated third-party open access to the high-pressure gas transmission network. Order 636, by unbundling transportation from supply, provides further assurance that pipelines will transport third-party gas on a non-discriminatory basis. Pipeline companies must provide access to storage and transportation facilities to all parties on a

194 Energy Information Administration (2003a) projects less dramatic growth in the electric power share of gas demand, from 22 to 29 percent (instead of from 29 to 45 percent) and a much smaller decline in the residential share, from 21 to 19 percent (instead of from 22 to 15 percent). EIA projects similar changes in the industrial share, from 35 to 31 percent (instead of from 23 to 19 percent) and commercial share, from 14 to 13 percent (instead of from 14 to 12 percent). APERC has higher electric and lower industrial shares since it counts industrial cogeneration as electric.

195 Energy Information Administration (1999) pages 194-7, EIA (2000a), EIA (2000c).

196 Energy Information Administration (1999) pages 198-200.

non-discriminatory basis. They must also make accurate and timely information on the availability of these facilities available to all parties. With unhindered access to unbundled supply, transport, storage and backup services, large electricity generators and industrial firms as well as local distribution companies can contract for each service separately from the least-cost supplier.[197]

PRINCIPAL PLAYERS IN THE UNITED STATES GAS MARKET

Gas Producers in the United States

Note: There are 24 major gas producers and some 8,000 independent producers in all.
Amerada Hess, BP Amoco, Anadarko Petroleum, Atlantic Richfield, BP America, Burlington Resources, Chevron, Clark Refining and Marketing, The Coastal Corporation, Conoco, El Paso Energy, Equilon Enterprises, Exxon Mobil, Fina, Kerr-McGee, Lyondell-Citgo Refining, Motiva Enterprises, Occidental Petroleum, Phillips Petroleum, Shell Oil, Sun Company, Tesoro Petroleum, Texaco, Tosco, Ultramar Diamond Shamrock, Union Pacific Resources Group, Unocal, USX, Valero Energy, The Williams Companies

Owners and Operators of Gas Transmission Pipelines in the United States

Note: Pipelines with firm capacity of at least 1 Trillion Btu per day are listed; there are some 140 companies in all.
Central: Williams Natural Gas, Colorado Interstate Gas, Northern Border Pipeline, Mississippi River Transmission, Questar Pipeline
Midwest: Natural Gas Pipeline Company of America, ANR Pipeline, Great Lakes Gas Transmission, Panhandle Eastern Pipe Line, Trunkline Gas
Northeast: Transcontinental Gas Pipe Line, Columbia Gas Transmission, Tennessee Gas Pipeline, CNG Transmission, Texas Eastern Transmission, Algonquin Gas Transmission, National Fuel Gas Supply, Iroquois Gas Transmission System
Southeast: Columbia Gulf Transmission, Southern Natural Gas, Florida Gas Transmission, Texas Gas Transmission
Southwest: Noram Gas Transmission, Koch Gateway Pipeline, eight others
West: El Paso Natural Gas, Northwest Pipeline, Pacific Gas Transmission, Transwestern Pipeline
Others: Northern Natural Gas

Owners and Operators of Gas Distribution Systems in the United States

Note: Only the few largest distribution companies in each region are listed; there are many more in each.
Central: Public Service of Colorado, Montana-Dakota, KN Energy, Colorado Springs Utilities
Midwest: Peoples' Gas Light & Coke, Illinois Power, Indiana Gas, Utilicorp, East Ohio Gas
Northeast: Boston Gas, Equitable Gas, National Fuel Gas Distribution, UGI Utilities, NJ Natural Gas, Public Service Company of North Carolina
Southeast: Columbia Gas of Ohio, Dayton Power & Light, Commonwealth Gas, Columbia Gas of PA, Louisville Gas & Electric, Columbia Gas of Kentucky
Southwest: Texas Gas Transmission Corporation
West: PG&E, BC Gas

Retail Gas Marketers in the United States

Note: Only a few of the largest gas marketers are listed for each region; there are some 260 in all.
Central: Anthem Energy, Questar Energy Trading
Midwest: Midcon Gas, Texaco Natural Gas, Energy Source, Proliance Energy
Northeast: Con Edison Solutions, Columbia Energy Services, Niagara Mohawk Energy Marketing, North Atlantic Energy, North Atlantic Utilities, NYSEG Solutions, Texaco Natural Gas
Southeast: Exxon, Texaco Natural Gas, Columbia Energy Services
Southwest: FINA Natural Gas, Pennunion Energy Service, Natural Gas Clearinghouse, Noram Energy, Duke Energy
West: Southern Company Energy Marketing, Coastal Gas Marketing

Source: Energy Information Administration (1999). Some company names may have changed.

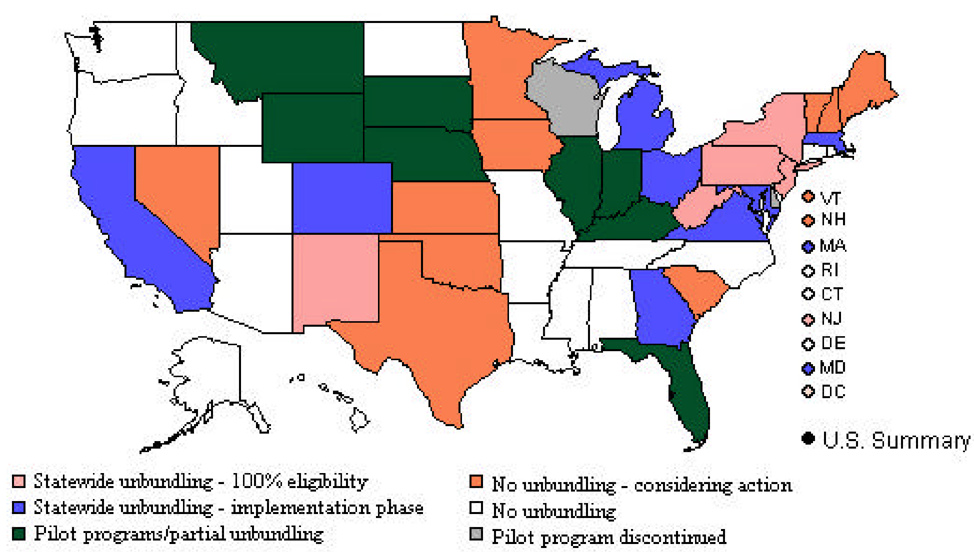
197 International Energy Agency (2002g) page 107.

Access to gas distribution services, which smaller customers require if they are to have a choice of suppliers, is also increasingly widespread. With approval of state regulatory commissions, most local distribution companies have offered unbundled transportation and storage services to industrial customers and larger commercial customers, allowing shopping for such services by firms that are not large enough to access the transmission pipeline grid directly. As of 2001, about 81 percent of sales to industrial customers and 34 percent of sales to commercial customers in the US were made on such an unbundled basis.[198] For residential customers, a much smaller percentage of sales are so far made on such a basis, but a growing number of states allow the purchase gas from retail marketers as well as the traditional gas utility. By the end of 2002, residential access to unbundled gas services was offered in six states, was being implemented in another eight states, was offered through a pilot programme in eight states, and was being considered by ten states.[199]

MARKET MODEL AND COMPETITION

The United States would seem most closely to fit the retail competition model. Almost all electric power producers, as well as firms representing three-quarters of all industrial gas demand and one-quarter of commercial gas demand, are shopping around for the least-cost gas. Roughly half the states provide retail choice for residential customers as well, or are in the process of doing so. Consequently, as of the end of 2001, there were over 150 retail gas marketers in all, and competition among them is apparently vigorous. Among states with full retail unbundling or in the process of implementing it, New York had 50 competing suppliers, Maryland 12, Pennsylvania 10, Georgia and Ohio 8 each, Virginia 4, and New Jersey and the District of Columbia 3 each. On the other hand, California, Colorado, Massachusetts, New Mexico and West Virginia had none so far, perhaps because retailers were awaiting implementation or considered the market too small. Also, not all marketers survive; in New York, the number had declined to 44 by the end of 2002.[200]

Figure 69 Retail Supplier Choice for Residential Gas Customers in the US in 2002



Source: Energy Information Administration

198 Energy Information Administration (2003c), tables 17 and 18.

199 Energy Information Administration (2003d).

200 Energy Information Administration (2002a, 2003e).

Retail competition has evolved upon a base of wholesale competition that was put in place earlier. A series of legislative measures deregulated the wellhead prices of natural gas production in the US between 1978 and 1989. The Natural Gas Policy Act of 1978 ended wellhead price controls for "new" gas as of 1985, and the Natural Gas Wellhead Decontrol Act of 1989 lifted all remaining wellhead price controls. With these measures in place, retail gas suppliers and large gas users can buy their gas from the most cost-competitive source. There are several competing producers of gas in the United States, as well as several competing producers in Canada from which gas is imported

New York is the largest state market for natural gas in which retail choice of suppliers has been fully implemented. The state is highly diversified in its gas consumption, with 32 percent of gas demand occurring in the residential sector and 30 percent in the commercial sector in 2001. The New York State Public Service Commission issued a Gas Policy Statement in November 1998 which directed local distribution companies (LDCs) to cooperate with retail gas marketers to increase the number of customers buying gas from such marketers. The Statement envisioned that LDCs should exit the retail supply business over a three-to-seven-year transition period, though a subsequent study concluded that the market was not yet sufficiently competitive for this to happen. By October 2002, 7.5 percent of residential customers in New York had switched gas suppliers.[201]

There is little vertical integration between gas and electricity markets in the United States with respect to production and transmission functions. There are many competing power generators in the electricity market, each of which has a choice among many competing gas producers. Few companies engaged in the production or transmission of gas are also engaged in the generation of electricity. Thus, there is generally no incentive for a gas company to provide gas on a preferential basis to any electricity generator, and it will sell to the generator willing to pay the most. Conversely, there is generally no reason why any electricity generator would wish to obtain gas from any but the least-cost source of supply. Moreover, under FERC Order 636, gas production, transportation and retail supply must be conducted by functionally separate businesses, with information firewalls between them. So even if a gas producer or transporter wished to direct cheap gas toward an affiliated electricity generator, it would find it difficult to do so.

On the other hand, there is a growing convergence of United States gas and electricity markets at the level of distribution and retail supply. In many population centres, gas and electric distribution facilities are owned by the same gas and electric company. Local gas and electric companies usually have strong retail arms as well, not only in states that have not yet opened their local markets to retail competition (where they retain retail monopolies) but also in states that have. There are probably real efficiencies from the consolidation of retail functions like billing and metering for both kinds of energy in the same firm. If functional separation of distribution and retail arms can be effectively enforced, so that local distribution monopolies do not provide gas or power on a preferential basis to their retail affiliates, and so that competing retailers can obtain through local distribution companies the gas and power they need to serve customers, such consolidation should not have adverse consequences for the efficiency of gas or electricity supply.[202]

PRICE TRENDS

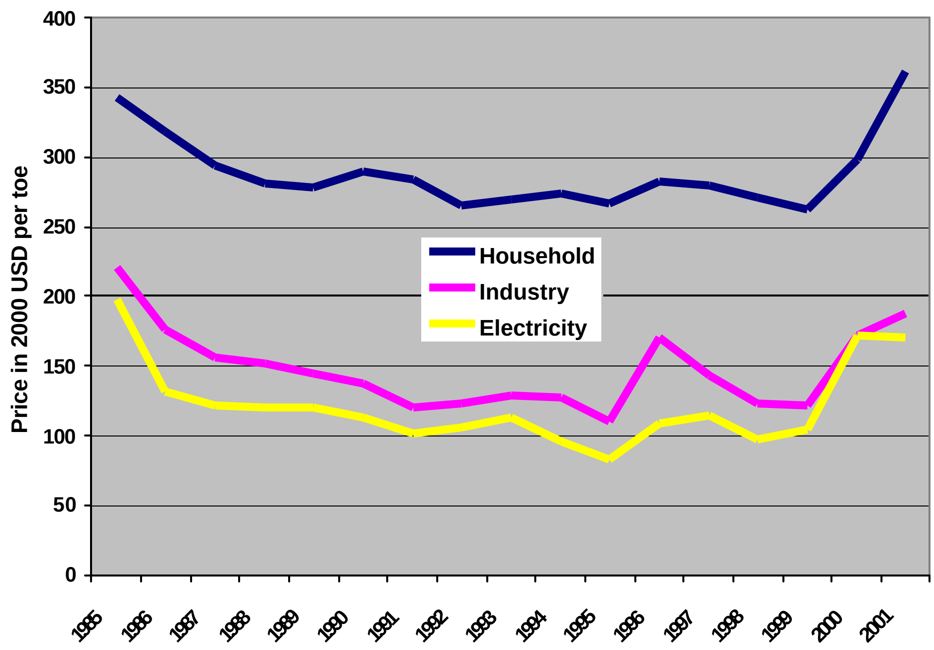
Deregulation of wellhead natural gas prices between 1978 and 1989, together with open access to competing gas supplies through Order 436 in 1985 and Order 636 in 1992, permitted a steep decline in delivered gas prices. For industrial customers, the real price in 2000 US$ was halved from over US$6 per thousand cubic feet in 1985 to about US$3 in 1995 (from US$221 to US$110 per tonne oil equivalent). The real price for electric power producers was more than halved from over US$5 to about US$2.50 over the same period (from US$197 to US$84 per toe). Meanwhile, residential and commercial gas prices declined in real terms by about one-third (residential prices from US$342 to US$266 per toe). In response to lower prices, together with a lifting of moratoria on new gas-fired power plants, the availability of highly-efficient combined cycle gas turbines, and

[201] Energy Information Administration (2003e).

[202] See EIA (1999), pages 147-67, for an interesting discussion of corporate combinations in the gas industry.

growing restrictions on emissions of air pollutants which favoured low-emitting gas-fuelled facilities, gas demand grew from 16 trillion cubic feet in 1984 to 23 trillion cubic feet in 1999. [203]

Figure 70 Natural Gas Prices in the United States, 1985-2001



Source: International Energy Agency and US Department of Commerce

Natural gas prices spiked during the winter of 2000-2001, with average wellhead prices nearly triple those of the previous winter, but prices later subsided. The price spikes were largely due to strong demand in the power sector, where most new generating capacity in recent years has been gas-fired, as well as declining production in the late 1990s, high heating demand and temporarily low levels of gas in storage. Gas demand jumped by 4.8 percent in 2000 after increasing an average of 1.7 percent per year between 1996 and 1999. Demand for gas in the electric power sector grew at a searing pace of nearly 11 percent per year between 1996 and 2000, as 21 gigawatts of gas-fired generating capacity was built between 1995 and 1999 and another 22 gigawatts came on line in 2000. In this context, spot prices at Louisiana's Henry Hub, upon which many gas contract prices are based, remained above US$5 per million Btu from September 2000 through February 2001.

The subsequent decline in prices, with spot prices at the Henry Hub reference point falling by August 2001 to half the winter's levels, can be attributed to faltering demand in the industrial sector, increased production in response to higher prices, and more normal storage levels. In response to higher prices, the number of gas drilling rigs in operation more than doubled from 392 in April 1999 to 636 in December 1999 to 854 in December 2000. An average of 720 gas rigs were in operation in 2000, up 45 percent from 1999. With a rise in gas well completions, production increased by 0.7 trillion cubic feet, from 18.62 Tcf in 1999 to 19.32 Tcf in 2000. More than 60 pipeline construction projects were completed in 1999 and 2000, providing 12.3 billion cubic feet per day of new capacity, or a 15 percent increase over the total capacity available in 1998. By the summer of 2001, the Henry Hub spot price had subsided to just around US$2.50 per million Btu. [204]

[203] International Energy Agency (2002g) page 71, IEA (1997) pages II.19-21, IEA (2002a) pages III.30-32. Real prices calculated by dividing prices in current US$ from IEA by implicit GDP deflators from US Department of Commerce.

[204] US Department of Energy (2001).

This recent experience with price spikes in the US natural gas market provides an interesting illustration of how market reforms may enhance security of supply. A large and sudden increase in demand produced a temporary imbalance between supply and demand which in turn produced a sharp increase in gas prices. The higher gas prices then provided a powerful incentive to conserve, explore for new gas supplies, produce extra gas, and build new pipelines to bring gas to customers. As a result, prices subsided to a level that was only about 30 percent higher than that which had prevailed prior to the crunch, and a major increase in demand was fully met by increased supply.

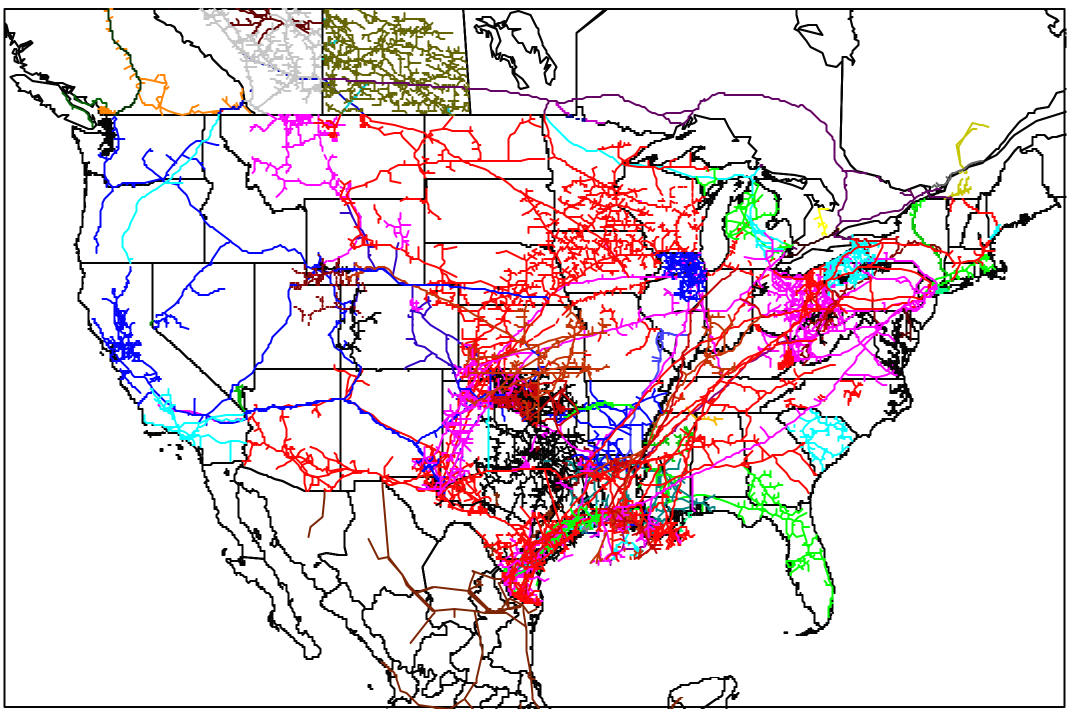
GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

The United States had some 474,000 km of gas transmission pipeline and 1,458,000 km of gas distribution pipeline as of June 2002.[205] About 74 percent of the transmission pipeline belonged to the interstate grid, with the capacity to move over 94.0 Bcf (2.66 Bcm) per day between regions at the end of 2000.[206] There are well-developed gas distribution networks in most urban areas, so that 73 percent of households had access to gas and 62 percent were purchasing gas as of July 2001.[207]

The network of transmission pipelines is most extensive in the key gas-producing states of Texas, Louisiana and Oklahoma and in major gas consuming states like New York, Ohio and Pennsylvania, but it reaches all states on the US mainland. There are also many pipeline linkages with Canada, which serve mainly for gas imports from the Canadian West but also for some gas exports via the US Midwest, including re-exports of Canadian gas that has moved along US pipelines. Almost all gas is moved by pipeline, but 1 percent of gas supply is imported as LNG.

Figure 71 United States Natural Gas Transmission Network



Source: U.S. Department of Transportation, Office of Pipeline Safety

[205] EIA (2002b). EIA data indicate 294,405 miles of transmission pipeline and 906,000 miles of distribution pipeline.

[206] EIA (2001a), pages 1, 2. For details, see EIAGIS-NG Natural Gas Pipeline State Border Capacity Database.

[207] EIA (2001b).

Some 38,000 miles (61,000 km) of new transmission lines and 263,000 miles (421,000 km) of new distribution lines will be needed to accommodate what is projected to be a 50 percent increase in demand for gas through 2020. New transmission lines are needed not only to accommodate growth in demand, but also to adjust for the fact that demand centres have shifted from the Midwest toward the South and West, while production has shifted in part from the Southwest to the Gulf of Mexico and Canada.[208] About a third of the new transmission lines will be needed in just the three years from 2003 through 2005, when it is anticipated that some 12,700 miles (20,300 km) of new lines with a capacity of 35.9 Bcf (1.02 Bcm) per day will be built at an estimated cost of $36.7 billion.[209] Extrapolating from these figures, the investment required for new gas transmission lines through 2020 could exceed $100 billion.

INFRASTRUCTURE INVESTMENT INCENTIVES

The gas industry in the United States is regulated at federal and state levels by independent agencies. The Federal Energy Regulatory Commission (FERC) regulates the routes and tariffs of interstate gas pipelines. Its approval is required for construction of new pipelines and expansion of existing ones, as well as for rate-setting methods used by pipeline companies. In general, FERC seeks to ensure that proposed pipelines will be used and thus paid for if built. The US Department of Energy regulates pipelines for natural gas imports and exports. The US Department of Transportation, through its Office of Pipeline Safety, sets safety standards and procedures for pipelines, and it must certify each pipeline segment as safe before it can begin operation. The US Environmental Protection Agency determines whether pipelines meet environmental guidelines. State bodies regulate the rates and pipelines of local distribution companies.[210]

With respect to the gas transportation network of high-pressure pipelines, investment incentives for grid enhancement appear to be adequate. Both federal and state governments generally allow a return on approved grid expansions that is based on the weighted cost of borrowing capital. The Energy Information Administration (EIA) reports that over the four-year period from 1997 through 2000, pipeline capacity grew more than 5 Bcf per day each year, or a total of more than 20 Bcf per day, at a cost of more than $2 billion annually or $8 billion in total. During that period, "expenditures on new pipeline development and major new extensions and laterals form existing systems accounted for more than 70 percent of total expenditures, while expansions to existing systems accounted for the rest." Overall, the interstate pipeline grid's capacity increased by 27 percent between 1990 and 2000. The EIA concludes that "to date, the U.S. natural gas pipeline industry has been able to finance and install the additional infrastructure needed to accommodate the decade-long demand growth on the network" and that "barring any major disruption of financial markets, [it] should be able to continue doing so."[211]

However, the National Energy Policy has noted that infrastructure expansion may be impeded by regulatory factors: "Several factors complicate efforts to meet the need for increased pipeline capacity, including encroachment on existing rights-of-way and heightened community resistance to pipeline construction. Currently it takes an average of four years to obtain approvals to construct a new natural gas pipeline. In some cases it can take much longer. The projected growth in energy demand has called into question whether regulatory actions and permitting processes can keep pace with the necessary construction of new facilities for storage and delivery. Consistent federal, state and local government policies, and faster, more predictable regulatory decisions on permitting for oil and natural gas pipelines are needed to enable timely and cost-effective infrastructure development."[212] Largely because of regulatory factors, the bulk of pipeline capacity enhancements in recent years have focused on increasing the capacity of existing lines through new compressor stations, as well as looping with parallel lines that do not require new rights-of-way.

---

208 National Energy Policy Development Group (2001), pages 7-12, 7-13.

209 EIA (2003b)

210 EIA (2001a), page 3.

211 EIA (2001a), pages 2, 5, 6, 16.

212 National Energy Policy Development Group (2001), pages 7-12.

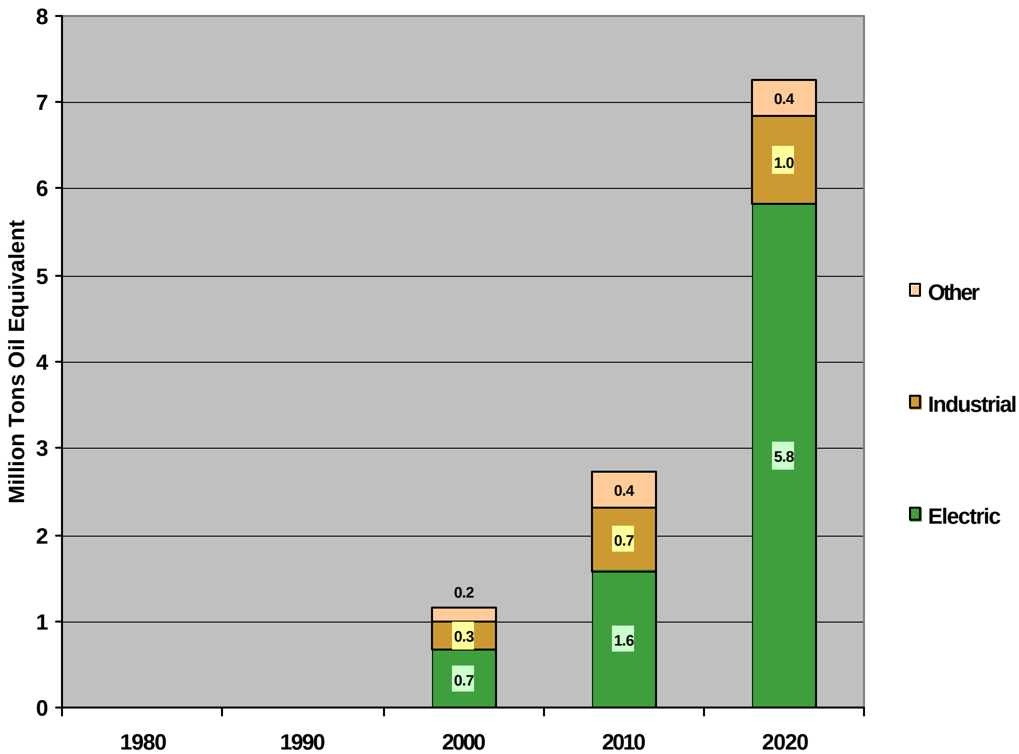
VIET NAM

GAS MARKET SETTING[213]

Viet Nam produces a small but rapidly growing amount of natural gas that makes the economy to be entirely self-sufficient in domestic gas supply.

- Production and primary supply of gas are projected to increase from 1.2 Mtoe in 2000 to 7.3 Mtoe in 2020, with rapid demand growth averaging 8.9 percent per annum from 2000 to 2010 and 10.3 percent per annum from 2010 to 2020.

Figure 72 Evolution of Natural Gas Use in Viet Nam, 2000-2020



Viet Nam's natural gas use is entirely devoted to energy transformation and industry. Nearly three-fifths of the economy's gas is used for electric power generation, and the share is trending upward. The other two fifths are divided between oil liquefaction and various industrial applications. There is no current or anticipated use of gas in the commercial or residential sector.

- Rapid growth is anticipated in use of gas for electric power generation, with demand jumping eight-fold from 0.7 Mtoe in 2000 to 5.8 Mtoe in 2020, so that the power sector's share of gas use increases from 58 percent to 80 percent.
- Industrial gas use is projected to triple from a small base of 0.3 Mtoe in 2000 to 1.0 Mtoe in 2020, but its share of the gas market is projected to fall by nearly half, from 27 percent to 14 percent, due to much faster growth in power sector use.

213 Data from APERC (2002a) and more detailed internal energy balance tables. Historical data for 1980 and 1990 were not available in the case of Viet Nam. Projections for 2000, 2010 and 2020 were made by APERC.

- Other gas uses, including oil liquefaction and refining, should roughly double between 2000 and 2020, their share of gas demand falling from 15 to 6 percent.

GAS MARKET STRUCTURE AND OPERATION

GAS MARKET PLAYERS

Viet Nam's gas is produced entirely by the state-owned monopoly, Petrovietnam, in partnership with various international oil companies. Production is carried out mainly through joint operating company contracts, which are like extended production sharing contracts. According to the Petroleum Law amendments of 2000, such contracts may be granted for gas production for up to 30 years, and the extent of Petrovietnam's participation is negotiable.[214]

PRINCIPAL PLAYERS IN VIET NAM'S GAS MARKET

Gas Producers in Viet Nam
Petrovietnam

Owners and Operators of Gas Transmission and Distribution Pipelines in Viet Nam
Petrovietnam Gas Company

Source: Petrovietnam

The transmission of gas from production fields to large customers and distribution points is carried out entirely by Petrovietnam Gas Company (PVGC), a subsidiary of Petrovietnam. Private firms often participate in the construction and operation of high-pressure pipelines through joint ventures in which PVGC retains a majority share.[215]

Typically, when Petrovietnam develops and transports gas from a particular field, it has customers for most of the gas guaranteed in advance. The gas is used mainly for power and fertiliser production, although a distribution centre is being built to expand gas use to a broader range of industrial, commercial and residential users in the Mekong Delta and Ho Chi Minh City area. Demand for gas from powerplants is typically guaranteed through long-term take-or-pay contracts with the powerplants' owners, who in turn obtain guarantees for their output from the state-owned power utility, Electricity of Vietnam (EVN). Demand for gas from fertiliser plants is typically guaranteed because Petrovietnam owns them, essentially supplying its own gas needs.[216]

---

214 Petrovietnam (2002).

215 *Ibid*. For example, the pipeline from Nam Con Son basin to Phu My power complex, including a 365 km offshore segment to Dinh Co terminal and a 38 km land segment thence to Phu My, was completed in 2002 by a joint venture of Petrovietnam (with a 51 percent share) and BP (with 49 percent). It is Viet Nam's most important pipeline to date, with an initial transport volume of 2.7 Bcm per year, scheduled to grow to 7 Bcm per year.

216 *Ibid*, IEEJ (2002a), pages 427-8. For example, consider the Phu My complex, which is the main destination for gas from the Nam Con Son Basin. The 715 MW Phu My 2.2 plant, to enter service in 2004, is being built under a Build-Operate-Transfer (BOT) contract with EVN by the Mekong Energy Corporation, a consortium of Electricité de France (with a 56 percent share), Sumitomo (28 percent), and Tokyo Electric Power Company (16 percent). Similarly, the 717 MW Phu My 3 plant, to be finished in 2003, is being built by Phu My 3 BOT Power Company, a consortium with even shares held by BP, Semb Corporation of Singapore, and a joint corporation formed by the Kyushu Electric Power Company and Nisho Iway Corporation of Japan. In each case, the consortium purchases gas from PVGC under a 20-year take-or-pay contract and sells the electricity it produces to EVN under another 20-year take-or pay contract. PVGC is the sole owner of the Phu My Urea Project which will use gas to produce 740 kilotons per year of urea for fertiliser starting in 2003. Perhaps half of the gas may ultimately go, at a later stage, to buyers that have not been lined up in advance. The distribution centre at Phu My, being built by VNGC in a joint venture with Korea's Daewoo and others, is to supply as much as 10 Mcm per day (3.6 Bcm per year) to customers in Ho Chi Minh City and Dong Nai and Ba Ria-Vung Tao provinces when completed in 2006, about half the current pipeline's capacity.

UNBUNDLING AND THIRD PARTY ACCESS

The gas market functions in Viet Nam are not effectively unbundled. Gas production, high-pressure transmission pipelines, and distribution systems are all controlled by Petrovietnam. In any case, there are no competing gas producers to whom access might be granted.

Viet Nam's natural gas market is not formally regulated. While the Ministry of Planning and Investment and the Ministry of Industry formulate energy policy and oversee the gas market's development, Petrovietnam is in practice allowed a high degree of autonomy in its operations.

MARKET MODEL AND COMPETITION

The natural gas market in Viet Nam most closely conforms to the vertically integrated monopoly model. Most of the gas from fields developed so far has been dedicated to specific gas-fired power plants which have signed take-or-pay contracts for gas and to fertiliser plants which Petrovietnam owns. The fields were developed with contractual assurances that the gas would be used by the power and fertiliser plants, which in turn were built with contractual assurances that the field and pipeline would be developed. So the market consists primarily of bilateral contracts and self-supply that integrate gas production and transmission with power sector customers.

There is thus a high degree of integration between gas and electricity markets in Viet Nam. For the 18 percent of the economy's electricity that was generated from gas in 2001, there was only a single gas supplier, from which gas was obtained under long-term take-or-pay contracts. Even if a measure of wholesale competition is introduced in the electric power sector, with the state utility EVN buying power from independent power producers, the impact of such competition is apt to be substantially diminished by the fact that all competitors must obtain gas from the same source.

GAS MARKET REGULATION AND INFRASTRUCTURE POLICY

GAS TRANSPORTATION INFRASTRUCTURE

Viet Nam currently has some 500 km of gas transmission pipelines, including a 100 km line from the Bach Ho field and a 400 km line from the Lan Tay and Lan Do gas reserves to the Phu My power and fertiliser complex. Feasibility studies are underway regarding a 332 km pipeline from offshore to Ca Mau province and a 150 km pipeline between Phu My and Ho Chi Minh City.[217]

INFRASTRUCTURE INVESTMENT INCENTIVES

Investment incentives for construction of the transmission infrastructure required to deliver gas from the Nam Con Son and Cuu Long gas basins have apparently been adequate. Since a large share of the gas has guaranteed customers, the returns on investment can be predicted with a high degree of confidence. On the other hand, since infrastructure is built under very long-term contracts, by consortia that face little competition once the contracts are signed, the construction may well be less efficient and more costly than it would be in a more competitive environment.

217 EIA (2003b).

NATURAL GAS PRICE DATA

PRICE DATA SOURCES AND CALCULATIONS

The natural gas price data that are illustrated in this report and presented in this note were obtained from published sources as follows:

- *For most APEC economies in the Organisation for Economic Cooperation and Development (Australia, Canada, Japan, Mexico, New Zealand, United States):* Data on sectoral gas prices in current US dollars per tonne oil equivalent (toe) were taken directly from IEA (1997) *Natural Gas Information 1996* and (2002a) *Natural Gas Information 2002.*
- *For Indonesia:* Data on domestic gas prices in current US dollars per million Btu were taken from APERC (2001a) *APEC Energy Pricing Practices: Natural Gas End-use Prices.* Data on export gas prices in current US dollars per million Btu were taken from Ministry of Energy and Mineral Resources (2002) *Handbook of Indonesia's Energy Economy Statistics 2002.* Prices in current US dollars per toe were then obtained assuming a heat content of 39.68 million Btu per toe from IEA (2002a) *Natural Gas Information 2002*.
- *For Korea:* Data on sectoral gas prices in current won per cubic metre were taken from Korea Energy Economics Institute (2002) *Korea Energy Review Monthly*. These were converted to current won per toe assuming heat contents of 10,500 kilocalories per cubic metre and 10 million kilocalories per toe. Prices in current US$ per toe were then obtained using won-to-dollar exchange rates from IEA (2002b) *Energy Prices and Taxes Quarterly Statistics* for 1993-2001 and International Monetary Fund (2002) *International Financial Statistics Yearbook* for 1987-92.
- *For Russia:* Data on gas prices in current US dollars per thousand cubic metres were taken from IEA (2002f) *Russia Energy Survey 2002*. These were converted to current US$ per toe assuming heat contents of 37,579 kilojoules per cubic metre (or 0.037579 terajoules per thousand cubic metres) and 0.00002388 million toe per terajoule (23.88 toe per terajoule) from IEA (2002a) *Natural Gas Information 2002*.
- *For Chinese Taipei:* Data on sectoral gas prices in current US dollars per toe were taken directly from IEA (2002b) *Energy Prices and Taxes Quarterly Statistics.*
- *For Thailand:* Data on sectoral gas prices in current baht per million Btu were obtained from the Energy Policy and Planning Office. These were converted to current baht per toe assuming a heat content of 39.68 million Btu per toe from IEA (2002a) *Natural Gas Information 2002.* Prices in current US dollars per toe were then obtained using baht-to-dollar exchange rates form the Bank of Thailand.
- *Comparative oil prices* were obtained in current dollars per barrel from IEA (2002) *Oil Information 2002* and (1993) *Oil and Gas Information 1992.* They were converted to current dollars per toe using data on barrels of crude per tonne from IEA (2002).
- *In all cases*, prices in current US dollars per toe were converted to constant year 2000 US dollars per toe using gross domestic product (GDP) price deflators from the United States Department of Commerce, Bureau of Economic Analysis.

PRICE DATA FOR SELECTED APEC ECONOMIES

Natural gas and oil price data are presented in the tables below. The first table shows gas prices in current US dollars per toe. The second shows gas prices in constant 2000 US dollars per toe. The third table shows comparative oil prices in current and constant 2000 US dollars per toe.

NOMINAL NATURAL GAS PRICE TRENDS IN SELECTED APEC ECONOMIES (Current US Dollars per Tonne Oil Equivalent at Prevailing Exchange Rates)

HOUSEHOLD GAS PRICES (Nominal US Dollars per toe)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$160.91	$149.62	$161.49	$170.67	$175.34	$185.48	$181.59	$184.44	$176.91	$175.58	$162.16	$169.66	$170.61	$169.84	$212.37	$199.43	
USA	$235.79	$224.61	$213.44	$210.74	$216.91	$233.77	$237.81	$227.31	$237.21	$246.48	$244.32	$264.32	$266.82	$262.19	$257.17	$298.42	$369.46
Chile																$611.38	$621.65
Japan	$631.81	$832.28	$902.56	$977.69	$989.49	$945.99	$1,016.43	$1,072.45	$1,204.14	$1,307.93	$1,410.72	$1,294.12	$1,287.77	$1,068.45	$1,196.43	$1,294.07	
Korea			$447.80	$467.33	$449.18	$421.71	$406.99	$389.71	$386.00	$385.04	$403.83	$393.38	$365.18	$325.88	$356.65	$427.29	$398.66
Chinese Taipei						$439.35	$440.68	$446.76	$421.94	$416.37	$425.86	$410.97	$431.18	$372.21	$354.59	$397.68	
Australia	$186.24	$187.51	$205.97	$247.74	$264.12	$268.78	$287.60	$283.42	$276.56	$312.25	$317.89	$332.81	$332.34				
New Zealand	$115.60	$142.83	$197.52	$232.31	$223.00	$231.34	$254.58	$238.22	$254.15	$297.20	$363.38	$415.93	$437.70	$380.18	$379.28	$322.47	$296.56

ELECTRICITY GENERATION GAS PRICES (Nominal US Dollars per toe)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$69.20	$59.12	$55.20	$71.13	$58.67	$62.87	$68.33	$56.62									
USA	$136.15	$93.02	$88.69	$89.89	$93.64	$92.11	$84.94	$91.40	$99.18	$86.37	$76.82	$102.28	$109.48	$94.33	$102.09	$171.98	$175.11
Mexico	$83.13	$77.65	$70.90	$94.85	$100.11	$87.92	$70.45	$76.28	$90.85	$79.67	$61.57	$89.27	$99.34	$81.38	$88.27	$150.03	$168.85
Japan	$193.21	$148.96	$136.24	$139.70	$147.61	$167.13	$167.88	$158.41	$153.60	$145.66	$157.53	$165.67	$211.70				
Chinese Taipei						$284.87	$285.73	$285.01	$276.47	$268.17	$260.06	$234.03	$255.23	$218.90	$201.67	$246.17	
Thailand								$108.10	$102.33	$100.97	$104.30	$114.31	$112.07	$98.41	$97.31	$113.43	$128.55
Indonesia (Java)			$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39	$100.39

INDUSTRY GAS PRICES (Nominal US Dollars per toe)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$103.59	$97.70	$93.14	$92.21	$83.42	$83.69	$87.03	$83.71	$74.67	$78.47	$69.82	$71.14	$72.51	$70.55	$79.43	$89.80	
USA	$152.18	$124.44	$113.27	$114.04	$112.50	$111.44	$101.04	$106.34	$113.80	$113.80	$100.80	$159.15	$136.18	$119.03	$118.71	$171.33	$192.62
Mexico	$83.15	$77.65	$70.90	$94.85	$100.11	$87.92	$70.45	$76.28	$90.95	$79.67	$61.57	$89.27	$99.34	$81.38	$88.27	$150.03	$168.85
Japan	$418.36	$504.00	$495.71	$478.24	$449.71	$412.57	$424.68	$436.15	$464.93	$466.24	$490.44	$423.12	$463.31	$355.97	$385.82	$452.69	
Korea			$385.32	$381.10	$321.97	$269.80	$246.75	$231.55	$230.38	$230.40	$242.97	$233.00	$209.10	$194.97	$199.14	$245.72	$272.57
Chinese Taipei						$312.92	$313.86	$313.07	$296.77	$282.16	$291.81	$281.60	$307.46	$264.54	$248.30	$297.81	
Thailand								$152.16	$159.69	$164.56	$183.75	$186.34	$168.23	$132.36	$136.95	$152.65	$157.19
Australia	$95.02	$95.43	$98.45	$115.70	$115.84	$123.12	$135.97	$126.95	$121.37	$127.22	$132.43	$144.87	$135.76				
New Zealand	$95.61	$113.20	$150.56	$195.88	$169.87	$170.83	$176.67	$164.39	$163.62	$180.41	$202.99	$217.24	$221.98	$209.33	$217.42	$176.21	$162.68
Russia							$11.59	$3.01	$19.61	$24.07	$62.07	$58.17	$61.18	$18.28	$15.27	$15.27	$16.16
Indonesia (Java)	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36	$79.36			

EXPORT GAS PRICES (Nominal US Dollars per toe)

Russia							$102.30	$99.96	$98.40	$92.49	$105.86	$104.19	$110.88	$91.60	$69.20	$129.26	$151.55
Indonesia						$149.99	$138.09	$133.72	$124.20	$111.50	$119.04	$136.90	$135.31	$96.42	$118.64	$192.84	

REAL NATURAL GAS PRICE TRENDS IN SELECTED APEC ECONOMIES (Constant Year 2000 US Dollars per Tonne Oil Equivalent)

GDP PRICE DEFLATORS (US Department of Commerce, Bureau of Economic Analysis)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Base 1996	73.69	75.31	77.58	80.21	83.27	86.51	89.66	91.84	94.05	96.01	98.1	100	101.95	103.2	104.69	106.89	109.42
Base 2000	0.6894	0.7046	0.7258	0.7504	0.7790	0.8093	0.8388	0.8592	0.8799	0.8982	0.9178	0.9355	0.9538	0.9655	0.9794	1.0000	1.0237

HOUSEHOLD GAS PRICES (Year 2000 US Dollars per Tonne Oil Equivalent)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$233.41	$212.36	$222.50	$227.44	$225.08	$229.18	$216.49	$214.66	$201.06	$195.48	$176.69	$181.35	$178.88	$175.91	$216.83	$199.43	
USA	$342.02	$318.80	$294.08	$280.84	$278.44	$288.84	$283.51	$264.56	$269.59	$274.41	$266.21	$282.53	$279.75	$271.56	$262.57	$298.42	$360.92
Chile																$611.38	$607.28
Japan	$916.46	$1,181.28	$1,243.55	$1,302.90	$1,270.16	$1,168.85	$1,211.76	$1,248.19	$1,368.53	$1,456.15	$1,537.12	$1,383.28	$1,350.17	$1,106.65	$1,221.57	$1,294.07	
Korea			$616.97	$622.78	$576.60	$521.05	$485.20	$453.57	$438.70	$428.67	$440.01	$420.48	$382.87	$337.54	$364.14	$427.29	$389.45
Chinese Taipei						$542.85	$525.37	$519.97	$479.54	$463.55	$464.02	$439.29	$452.07	$385.52	$362.04	$397.68	
Australia	$270.15	$266.14	$283.79	$330.14	$339.04	$332.10	$342.87	$329.86	$314.32	$347.63	$346.37	$355.74	$348.44				
New Zealand	$167.68	$202.72	$272.14	$309.58	$286.26	$285.84	$303.50	$277.26	$288.85	$330.88	$395.94	$444.59	$458.91	$393.77	$387.25	$322.47	$289.70

ELECTRICITY GENERATION GAS PRICES (Year 2000 US Dollars per Tonne Oil Equivalent)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$100.38	$83.91	$76.05	$94.79	$75.31	$77.68	$81.46	$65.90									
USA	$197.49	$132.03	$122.20	$119.79	$120.20	$113.81	$101.26	$106.38	$112.72	$96.16	$83.70	$109.33	$114.78	$97.70	$104.24	$171.98	$171.06
Mexico	$120.58	$110.21	$97.69	$126.40	$128.51	$108.63	$83.99	$88.78	$103.25	$88.70	$67.09	$95.42	$104.15	$84.29	$90.12	$150.03	$164.95
Japan	$280.26	$211.42	$187.71	$186.17	$189.48	$206.50	$200.14	$184.37	$174.57	$162.17	$171.65	$177.08	$221.96				
Chinese Taipei						$351.98	$340.64	$331.72	$314.21	$298.56	$283.36	$250.15	$267.60	$226.73	$205.91	$246.17	
Thailand								$125.82	$116.31	$112.42	$113.64	$122.19	$117.50	$101.93	$99.36	$113.43	$125.58
Indonesia (Java)			$138.32	$133.78	$128.87	$124.04	$119.68	$116.84	$114.10	$111.77	$109.39	$107.31	$105.25	$103.98	$102.50	$100.39	$98.07

INDUSTRY GAS PRICES (Year 2000 US Dollars per Tonne Oil Equivalent)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$150.26	$138.67	$128.33	$122.88	$107.08	$103.41	$103.75	$97.43	$84.86	$87.36	$76.08	$76.04	$76.02	$73.07	$81.10	$89.80	
USA	$220.74	$176.62	$156.06	$151.97	$144.41	$137.69	$120.46	$123.77	$129.34	$126.70	$109.83	$170.12	$142.78	$123.29	$121.20	$171.33	$188.17
Mexico	$120.61	$110.21	$97.69	$126.40	$128.51	$108.63	$83.99	$88.78	$103.37	$88.70	$67.09	$95.42	$104.15	$84.29	$90.12	$150.03	$164.95
Japan	$606.85	$715.34	$682.99	$637.32	$577.27	$509.76	$506.29	$507.62	$528.40	$519.08	$534.38	$452.27	$485.76	$368.70	$393.93	$452.69	
Korea			$530.89	$507.86	$413.30	$333.36	$294.17	$269.50	$261.83	$256.50	$264.75	$249.06	$219.24	$201.94	$203.33	$245.72	$266.27
Chinese Taipei						$386.64	$374.17	$364.37	$337.29	$314.13	$317.96	$301.00	$322.36	$274.00	$253.52	$297.81	
Thailand								$177.09	$181.49	$183.21	$200.22	$199.18	$176.38	$137.10	$139.83	$152.65	$153.55
Australia	$137.83	$135.45	$135.64	$154.18	$148.70	$152.12	$162.10	$147.75	$137.94	$141.64	$144.30	$154.85	$142.34				
New Zealand	$138.69	$160.67	$207.44	$261.03	$218.05	$211.07	$210.62	$191.33	$185.96	$200.85	$221.18	$232.21	$232.74	$216.81	$221.99	$176.21	$158.92
Russia							$13.82	$3.50	$22.29	$26.80	$67.63	$62.18	$64.14	$18.93	$15.59	$15.27	$15.78
Indonesia (Java)	$115.11	$112.64	$109.34	$105.76	$101.87	$98.06	$94.61	$92.36	$90.19	$88.35	$86.47	$84.83	$83.21	$82.20			

EXPORT GAS PRICES (Year 2000 US Dollars per Tonne Oil Equivalent)

Russia							$121.96	$116.34	$111.83	$102.97	$115.35	$111.37	$116.25	$94.87	$70.66	$129.26	$148.05
Indonesia						185.32509	$164.62	$155.63	$141.15	$124.14	$129.71	$146.33	$141.87	$99.87	$121.14	$192.84	

OIL PRICE TRENDS IN SELECTED APEC ECONOMIES

NOMINAL OIL PRICES IN CURRENT US DOLLARS PER BARREL

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$27.85	$16.00	$18.59	$15.48	$18.56	$24.15	$20.83	$19.46	$17.19	$16.30	$17.76	$21.26	$20.59	$13.15	$17.85	$29.10	$24.87
USA	$26.78	$14.71	$17.73	$14.33	$17.50	$21.07	$18.23	$17.73	$15.87	$15.06	$16.74	$20.16	$18.34	$12.02	$17.06	$27.54	$22.07
Japan	$27.90	$16.08	$17.99	$15.47	$16.91	$22.64	$20.14	$19.30	$17.47	$16.48	$18.02	$20.55	$20.55	$13.68	$17.38	$28.72	$25.01
Australia	$28.17	$14.49	$19.00	$15.93	$17.63	$24.21	$20.70	$20.16	$17.91	$16.76	$18.53	$21.81	$21.78	$14.60	$18.38	$30.79	$26.61
New Zealand	$27.66	$16.94	$17.91	$15.25	$17.29	$21.97	$20.57	$19.41	$17.32	$16.93	$18.73	$21.86	$21.65	$14.63	$18.16	$29.95	$26.14

NOMINAL OIL PRICES IN CURRENT US DOLLARS PER TONNE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$200.13	$114.98	$133.59	$111.24	$133.37	$173.54	$149.68	$139.84	$123.53	$117.13	$127.62	$152.77	$147.96	$94.50	$128.27	$209.11	$178.72
USA	$198.17	$108.85	$131.20	$106.04	$129.50	$155.92	$134.90	$131.20	$117.44	$111.44	$123.88	$149.18	$135.72	$88.95	$126.24	$203.80	$163.32
Japan	$205.26	$118.30	$132.35	$113.81	$124.41	$166.56	$148.17	$141.99	$128.53	$121.24	$132.57	$151.19	$151.19	$100.64	$127.86	$211.29	$184.00
Australia	$221.64	$114.01	$149.49	$125.34	$138.71	$190.48	$162.87	$158.62	$140.92	$131.87	$145.79	$171.60	$171.37	$114.87	$144.61	$242.26	$209.37
New Zealand	$202.50	$124.02	$131.12	$111.65	$126.58	$160.84	$150.59	$142.10	$126.80	$123.94	$137.12	$160.04	$158.50	$107.11	$132.95	$219.26	$191.37

GDP PRICE DEFLATORS (US Department of Commerce, Bureau of Economic Analysis)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Base 1996	73.69	75.31	77.58	80.21	83.27	86.51	89.66	91.84	94.05	96.01	98.1	100	101.95	103.2	104.69	106.89	109.42
Base 2000	0.6894	0.7046	0.7258	0.7504	0.7790	0.8093	0.8388	0.8592	0.8799	0.8982	0.9178	0.9355	0.9538	0.9655	0.9794	1.0000	1.0237

REAL OIL PRICES IN YEAR 2000 US DOLLARS PER TONNE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Canada	$290.30	$163.19	$184.06	$148.24	$171.20	$214.42	$178.45	$162.76	$140.39	$130.41	$139.06	$163.30	$155.13	$97.87	$130.97	$209.11	$174.58
USA	$287.46	$154.50	$180.77	$141.31	$166.23	$192.65	$160.83	$152.70	$133.47	$124.07	$134.98	$159.46	$142.29	$92.13	$128.90	$203.80	$159.54
Japan	$297.74	$167.91	$182.36	$151.67	$159.70	$205.80	$176.64	$165.26	$146.07	$134.98	$144.45	$161.60	$158.51	$104.24	$130.55	$211.29	$179.74
Australia	$321.50	$161.81	$205.97	$167.03	$178.06	$235.36	$194.17	$184.61	$160.15	$146.81	$158.86	$183.42	$179.67	$118.98	$147.65	$242.26	$204.53
New Zealand	$293.73	$176.02	$180.66	$148.78	$162.49	$198.73	$179.53	$165.39	$144.11	$137.99	$149.41	$171.06	$166.18	$110.94	$135.74	$219.26	$186.95

REFERENCES

GENERAL REFERENCES

APEC Energy Working Group (2002). *APEC Energy Statistics 2000.* Singapore.

APEC Energy Working Group and Abareconomics (2002). *Deregulating energy markets in APEC: Economic and sectoral impacts.* Australian Bureau of Agricultural and Resource Economics, Canberra.

APERC (2000a). *Electricity Sector Deregulation in the APEC Region.* Tokyo.

APERC (2000b). *Natural Gas Infrastructure Development in Northeast Asia.* Tokyo.

APERC (2000c). *Natural Gas Infrastructure Development in Southeast Asia.* Tokyo.

APERC (2001a). *APEC Energy Pricing Practices: Natural Gas End-use Prices.* Tokyo.

APERC (2001b). *Energy Supply Infrastructure Development in the APEC Region.* Tokyo.

APERC (2002a). *APEC Energy Demand and Supply Outlook 2002.* Tokyo.

APERC (2002b). *APEC Energy Overview 2002.* Tokyo.

APERC (2002c). *Gas Storage in the APEC Region.* Tokyo.

Cedigaz – Centre International d'Information sur le Gaz Naturel et tous Hydrocarbures Gazeux (1999). *World LNG Outlook 99 Edition.* Guy Maisonnier, Rueil Malmaison, France.

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

IEA – International Energy Agency (1993). *Oil and Gas Information 1992.* Paris.

IEA – International Energy Agency (1994). *Natural Gas Transportation: Organisation and Regulation.* Paris.

IEA – International Energy Agency (1996). *Asia Gas Study.* Paris.

IEA – International Energy Agency (1997). *Natural Gas Information 1996.* Paris.

IEA – International Energy Agency (1998). *Natural Gas Pricing in Competitive Markets.* Paris.

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

IEA – International Energy Agency (2002). *Oil Information 2002.* Paris.

IEA – International Energy Agency (2002a). *Natural Gas Information 2002.* Paris.

IEA – International Energy Agency (2002b). *Energy Prices and Taxes Quarterly Statistics.* Paris.

IEA – International Energy Agency (2002c). *Flexibility in Natural Gas Supply and Demand.* Paris.

IEEJ – The Institute of Energy Economics, Japan (2002a). *Natural Gas Demand and Supply in the World.* Tokyo.

IMF – International Monetary Fund (2002). *International Financial Statistics Yearbook*.

Stern, Jonathan (2002). "Russian and Central Asian Gas Supply for Asia" in Oxford Institute for Energy Studies, *Natural Gas in Asia: The Challenges of Growth in China, India, Japan and Korea* (Stern, J. and Wybrew-Bond, I., editors). Oxford University Press.

US Department of Commerce, Bureau of Economic Analysis. GDP Price Deflators.

Williams, Michael F. (2003). *Implementing Gas Projects in Greater China.* APERC Annual Conference, Tokyo, 26-27 February 2003.

Wybrew-Bond, Ian (2002). "Middle East and South East Asia: Gas Exporting Regions to Asian Markets" in Oxford Institute for Energy Studies, *Natural Gas in Asia: The Challenges of Growth in China, India, Japan and Korea* (Stern, J. and Wybrew-Bond, I., editors). Oxford University Press.

AUSTRALIA

ActewAGL (2002). Website: www.actewagl.com.au

AlintaGas (2002). Website: www.alintagas.com

Australian Bureau of Agricultural and Resource Economics – ABARE (2002). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Australian Gas Association (2001). *Gas Statistics Australia 2001*. Canberra.

Australian Gas Association (2002). *Australia's Gas Industry in Brief.* Canberra.

Country Energy (2002). Website: www.countryenergy.com.au

Department of Industry, Tourism and Resources (2002). Response to Gas Market Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Dimasi, Joe, Executive General Manager, Regulatory Affairs Division, Australian Competition and Consumer Commission (2003). *Impacts of Gas Market Reform in Australia.* APERC Annual Conference, Tokyo, 26-27 February 2003.

Duke Energy (2003). Website: www.duke-energy.com.au

Energex (2002). Website: www.energex.com.au

EnergyAustralia (2002). Website: www.energy.com.au

Envestra (2002). Website: www.envestra.com.au

Epic Energy (2000). "MPF Status for Epic's Timor Sea Project." Media release, 8 November 2000.

Gas Reform Implementation Group (2002). *National Third Party Access Code for Natural Gas Pipelines as at 27 June 2002.*

Government of Australia (1997). *Gas Pipelines Access (South Australia) Act 1997.*

Government of Western Australia (2003). *Gas Tal*. Issue 7, page 2 (January 2003).

Independent Pricing and Regulatory Tribunal of New South Wales (2003). Website: www.ipart.nsw.gov.au

New South Wales Treasury (1998). *Great Southern Energy*. Website: www.treasury.new.gov.au/pubs/trp98_1/greatshth.htm

NUS International (1999). *Australia Now Among Cheapest Countries for Gas* (11 January 1999).

Office of the Regulator General, Victoria (2001). *Gas Industry Comparative Performance Report 2000*.

Origin Energy (2002). Website: www.originenergy.com.au

Productivity Commission (1998). *Performance of Government Trading Enterprises 1991-92 to 1996-97*.

SEA Gas (2002). Website: www.seagas.com.au. Media release, 29 May 2002.

TXU (2002). Website: www.txucorp.com

Victoria Essential Services Commission – Victoria ESC (2003). Website: www.esc.vic.gov.au

BRUNEI DARUSSALAM

Asia Trade Hub (2003). *Brunei Oil & Gas*. Website: www.asiatradehub.com/brunei/oil.asp.

National Chamber of Commerce (2002). "Aggressive Business Moves Expected from PetroleumBrunei." *National Chamber of Commerce International Business Daily* (14 February, 2002).

Petroleum Unit (2002a). Response to Gas Market Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Petroleum Unit (2002b). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

CANADA

Booth, Glenn, Chief Economist, National Energy Board (2003). *Natural Gas Market Reform: The Canadian Experience*. APERC Annual Conference, Tokyo, 26-27 February 2003.

Canadian Gas Association (2002). Measurement Canada Natural Gas Trade Sector Review.

National Energy Board (1996). *Natural Gas Market Assessment: Canadian Natural Gas Ten Years After Deregulation*. Calgary.

National Energy Board (2002). *Canadian Natural Gas Market Dynamics and Pricing: An Update*. Ottawa.

Natural Resources Canada (2000). *Energy in Canada 2000*. Ottawa.

Natural Resources Canada (2001). Website: www2.nrcan.gc.ca/es/erb/CMFiles/2001MarketReview

Natural Resources Canada (2002). *Canadian Natural Gas: 2001 Market Review and Outlook*. Ottawa.

Ontario Ministry of Energy (2003). Website: www.energy.gov.on.ca

Statistics Canada (2003a). Canadian Total Exports of Natural Gas in Gaseous State (HS 271121).

Statistics Canada (2003b). Consumer Price Index (CANSIM II).

CHILE

AESGener (2003). Website: www.aesgener.cl

Banco Central de Chile (2003). Website: www.bcentral.cl

Colbun (2003). Website: www.colbun.cl

Comisión Nacional de Energía (2002a). *Balance Nacional de Energía 1982-2001 Chile.* Santiago.

Comisión Nacional de Energía (2002b). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Comisión Nacional de Energía (2003). Website: www.cne.cl

Edelnor (2003). Website: www.edelnor.cl

Endesa (2003). Website: www.endesa.cl

Superintendencia de Electricidad y Combustibles (2003). Website: www.sec.cl

TGN – Transportadora de Gas del Norte (2003). Website: www.tgn.com.ar

TGS – Transportadora de Gas del Sur (2003). Website: www.tgs.com.ar

CHINA

China Energy Information Network (2003). Website: www.energy-china.com

China Energy Network (2003). Website: www.china5e.com

CNOOC – China National Offshore Oil Corporation (2003a). Website: www.cnooc.com.cn

CNOOC – China National Offshore Oil Corporation (2003b). Website: www.cnoocltd.com.cn

CNPC – China National Petroleum Corporation (2003). Website: www.cnpc.com.cn

Fridley, David (2002). "Natural Gas in China" in Oxford Institute for Energy Studies, *Natural Gas in Asia: The Challenges of Growth in China, India, Japan and Korea* (Stern, J. and Wybrew-Bond, I., editors). Oxford University Press.

IEA – International Energy Agency (2002d). *Developing China's Natural Gas Market.* Paris.

Lu, Wei, Deputy Director General, Development Research Center, State Council of the People's Republic of China (2003). *The Reform of Gas Market in China.* APERC Annual Conference, Tokyo, 26-27 February 2003.

National Bureau of Statistics (2001). *China Statistical Year Book 2001.* China Statistics Press, Beijing.

Paik, K-W. and Quan, L. (1998). *China Natural Gas Report.* Royal Institute for International Affairs and Xinhua News Agency.

PETEC Software and Services (2003). Website: www.worldoilweb.com/asp/info/chinaoil.asp

PetroChina (2003). Website: www.petrochina.com.cn

Roberts, Scott and Gilboy, George (2001). *Betwixt and Between: China's Natural Gas Industry under "Commercial Principles."* Cambridge Energy Research Associates, Cambridge, Massachusetts.

Sinopec – China Petroleum and Chemical Corporation (2003). Website: www.sinopec.com.cn

HONG KONG, CHINA

CLP Power and Exxon Energy Ltd (2001a). *Black Point Power Station.* Website: www.clpgroup.com

CLP Power and Exxon Energy Ltd (2001b). *Castle Peak Power Station.* Website: www.clpgroup.com

EMSD – Electrical and Mechanical Services Department, Hong Kong Special Administrative Region Government (2002a). Website: www.emsd.gov.hk/emsd/eng/pps/gas.shtml.

EMSD – Electrical and Mechanical Services Department, Hong Kong Special Administrative Region Government (2002b). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Hong Kong and China Gas Company (2000). Website: www.towngas.com/en/abouttg.

Information Services Department, Hong Kong Special Administrative Region Government (2002). *Hong Kong: The Facts.* Website: www.info.gov.hk/hkfacts/supplies.pdf

INDONESIA

American Embassy Jakarta (2002). *Petroleum Report Indonesia 2002.*

Jakarta Post (2002). Issue of 4 December 2002.

Ministry of Energy and Mineral Resources, Center for Energy Information (2002). *Handbook of Indonesia's Energy Economy Statistics 2002.* Jakarta.

Patmosukismo, S. (1994). "The Indonesian Gas Utilization and its Future Market Strategies," in *Asian Natural Gas – A Broad Spectrum of Opportunities* (Markuszewski, R., Kagei, K. and Harui, T., editors). Institute of Gas Technology, Chicago, 1995.

Pertamina (2003). Website: www.pertamina.com

PGN (2001). Website: www.pgn.co.id/annual_review and www.pgn.co.id/company_overview

Republic of Indonesia, People's Legislative Assembly (2001a). *Law of the Republic of Indonesia Number 22 Year 2001 Concerning Oil and Natural Gas.* Jakarta, 23 November 2001.

Republic of Indonesia, People's Legislative Assembly (2001b). *Elucidation of the Law of the Republic of Indonesia Number 22 Year 2001 Concerning Oil and Natural Gas. State Gazette of the Republic of Indonesia* Year 2001 Number 136, Jakarta, 23 November 2001.

JAPAN

Government of Japan (2003). "Notable Development: Electricity and Gas Market Reform" (tabled at 25th APEC Energy Working Group meeting, Portland, Oregon, USA, 20 June 2003).

Government of Japan and Government of the United States (2002). *First Report to the Leaders on the U.S.-Japan Regulatory Reform and Competition Policy Initiative* (June 25, 2002)

IEEJ – The Institute of Energy Economics, Japan (2002b). *Present State of Energy Industry in Japan – Focusing Especially on Electric and Gas Utilities.* Slide presentation by Hideo Hasegawa.

IEEJ – The Institute of Energy Economics, Japan (2002c). Response to Gas Market Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

MEES – *Middle East Economic Survey* (2001). Issue of 8 October 2001.

METI – Ministry of Economy, Trade and Industry (2003). Length of Pipelines by Entity.

METI – Ministry of Economy, Trade and Industry, Gas Market Division (2003). Summary of a Gas Regulatory Reform Proposed by the Urban Heat Energy Subcommittee, Advisory Committee for Natural Resources and Energy (March 2003).

METI – Ministry of Economy, Trade and Industry, Urban Heat Energy Subcommittee (2003). Recommended Framework for the Natural Gas Industry in the Future (20 February 2003).

Miyamoto, Akira (2002). "Natural Gas in Japan" in Oxford Institute for Energy Studies, *Natural Gas in Asia: The Challenges of Growth in China, India, Japan and Korea* (Stern, J. and Wybrew-Bond, I., editors). Oxford University Press.

KOREA

IEA – International Energy Agency (2002e). *Energy Policies of the Republic of Korea: 2002 Review.* Paris.

Korea City Gas Association (2002). *Annual Report of City Gas Business 2002.*

Korea Energy Economics Institute (2002). *Korea Energy Review Monthly (July 2002).*

Lee, Dongin, Head, Center for Gas Economics and Management, Korea Gas Corporation (2003). *Gas Market Reform in Korea and its Implications to Asia-Pacific LNG Trade.* APERC Annual Conference, Tokyo, 26-27 February 2003.

Ministry of Commerce, Industry and Energy (2003). Communication with Jaejoon Kim (26 May 2003).

MALAYSIA

Gas Malaysia (2003). Website: www.gasmalaysia.com

Haji Mohammad Nor, I.M.A., Director General, Department of Electricity Supply (1994). "Natural Gas for Power Generation and Energy Supply in Malaysia," in *Asian Natural Gas – A Broad Spectrum of Opportunities* (Markuszewski, R., Kagei, K. and Harui, T., editors). Institute of Gas Technology, Chicago, 1995.

Kim, P. L. (1994). "Natural Gas Distribution System in Malaysia," in *Asian Natural Gas – A Broad Spectrum of Opportunities* (Markuszewski, R., Kagei, K. and Harui, T., editors). Institute of Gas Technology, Chicago, 1995.

Prime Minister's Department (2003). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

MEXICO

Comisión Reguladora de Energía (1996). *Regulación de Gas Natural en México.* Mexico City.

Comisión Reguladora de Energía (2001a). *Características de los Permisos Otorgados en Distribución de Gas Natural.* Website: www.cre.gob.mx/estadisticas/stat98/distri.html

Comisión Reguladora de Energía (2001b). *Permisos de Transporte de Gas Natural Otorgados por la CRE.* Webside: www.cre.gob.mx/estadisticas/stat98/transp.html

Secretaría de Energía (2001). *Prospectiva del Mercado de Gas Natural 2001-2010.* Mexico City.

Secretaría de Energía (2002a). *Prospectiva del Mercado de Gas Natural 2002-2011.* Mexico City.

Secretaría de Energía (2002b). *Prospectiva del Sector Eléctrico 2002-2011.* Mexico City.

Secretaría de Energía (2003). Response to Gas Market Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

NEW ZEALAND

Ministry of Economic Development (2002a). *Draft Government Policy Statement: Development of New Zealand's Gas Industry*. Website: www.med./govt/nz/erc/gas/review/decisions/draft-gps.html

Ministry of Economic Development (2002b). *New Zealand Energy Data File January 2002*. Wellington. Website: www.med.govt.nz/erc/en_states.html.

Ministry of Economic Development (2002c). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Ministry of Economic Development (2003). *New Zealand Energy Data File January 2003*. Wellington. Website: www.med.govt.nz/erc/en_states.html.

PAPUA NEW GUINEA

Dow Jones Business News (2002). "Papua New Guniea Gas Project Adds Momentum, New Sale." Dec. 23, 2002. Website: www.dowjones.com .

High Commission of Papua New Guinea, Canberra (2001). *Electricity Supply*. Website: www.pngcanberra.com.

Oil Search (2002). Website: www.oilsearch.com.au/activities_page/activities_gas.html.

Pipe Line & Gas Industry (2001). 'S. Pacific financial agreements open way for some pipelines." Vol. 84, No. 11 (Nov-Dec 2001). Website: www.pipe-line.com

PNG Gas (2002). Website: www.pnggas.com.

PERU

Government of Peru (1999). *Ley de Promoción del Desarollo de la Industria del Gas Natural*. Lima.

Inter American Development Bank – IADB (2003). *Project Abstract – Peru – Camisea*. Website: www.iadb.org/exr/doc98/pro/ape0222.pdf

Ministry of Energy and Mines (2002a). *Plan Referencial de Energía al 2015*. Lima.

Ministry of Energy and Mines (2002b). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

PHILIPPINES

Department of Energy (2002a) *Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas* (Circular No. 2002-08-005). Manila

Department of Energy (2002b). *Natural Gas Industry*. Website: www.doe.gov.ph.

Department of Energy (2002c), *Philippine Energy Plan 2002-2011*.

Department of Energy (2002d). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Department of Energy (2003). *The Philippine Natural Gas Industry*. Slide presentation by Undersecretary J.V. Emmanuel A. de Dios.

Platts (2003). *Malampaya Gas Project Overview*. Website: www.platts.com/features/malampaya/overview.shtml.

RUSSIA

International Energy Agency (2002f). *Russia Energy Survey 2002*. Paris

MinEnergo (2000). *Main Provisions of the Energy Strategy of the Russian Federation to 2020.* Moscow.

MinEnergo (2001a). *Energy Strategy of the Russian Federation to 2020.* Moscow.

MinEnergo (2001b). *Fuel and Energy in Russia.* Moscow.

SINGAPORE

City Gas Pte Ltd (2002). Website: www.citygas.com.sg.

EIA – US Energy Information Administration (2002e). *Singapore Country Analysis Brief.* Website: www.eia.doe.gov/emeu/cabs/singapore.html.

Energy Market Authority (2002). *Restructuring of the Piped Gas Industry.*

Energy Market Authority (2003a). Response to Gas Market Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Energy Market Authority (2003b). Website: www.ema.gov.sg/Gas.

PowerGas Ltd (2002). Website: www.spower.com.sg.

Republic of Singapore (2001). *Gas Act 2001*. Website: http://statutes.agc.gov.sg.

Trade Partners UK (2002). *Power Market in Singapore.* Website: www.tradepartnersuk.gov.uk.

CHINESE TAIPEI

APERC (November 18, 2002), "Mission Report: Meeting with Taipower," Tokyo.

Energy Commission, Ministry of Economic Affairs (2003). Communication with Cheng-Chung Huang (7 April 2003).

Taiwan Power Company, Power Development Department (2002), "Briefing of Long Range Power Development Program (2002-2013)", Taipei.

Wang, W. (1994). "Expanding Natural Gas Distribution and the Environment in Taiwan," in *Asian Natural Gas – A Broad Spectrum of Opportunities* (Markuszewski, R., Kagei, K. and Harui, T., editors). Institute of Gas Technology, Chicago, 1995.

THAILAND

Bank of Thailand (2003). Website: www.bot.or.th

Energy Policy and Planning Office (2002). Response to Gas Market Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group meeting, Taipei, 8 October 2002).

Energy Policy and Planning Office (2003). Energy Data Base.

National Economic and Social Development Board (1996). *Eighth National Economic and Social Development Plan (1997-2001).* Bangkok.

PTT – Petroleum Authority of Thailand (2003). Website: www.pttplc.com

US Department of Energy, Office of Fossil Energy (2003). *An Energy Overview of the Kingdom of Thailand*. Website: www.fe.doe.gov/international/thaiover/html

UNITED STATES

EIA – Energy Information Administration (1999). *Natural Gas 1998 Issues and Trends.* Washington, DC.

EIA – Energy Information Administration (2001a). *Natural Gas Transportation – Infrastructure Issues and Operational Trends.* By J. Tobin, Natural Gas Division. Washington, DC.

EIA – Energy Information Administration (2001b). *2001 Residential Energy Consumption Survey*. Website: http://www.eia.doe.gov/pub/consumption/residential/2001hc_tables/housingunit_percent.pdf

EIA – Energy Information Administration (2002a). *Marketers Currently Providing Gas Service as of December 2001*. Website: www.eia.doe.gov/oil_gas/natural_gas/restructure/marketer_summary.xls.

EIA – Energy Information Administration (2002b). Response to Infrastructure Investment Questionnaire for APEC Economies (distributed at 24th APEC Energy Working Group, Taipei, 8 October 2002).

EIA – Energy Information Administration (2002c). *The Majors' Shift to Natural Gas.* Website: www.eia.doe.gov/emeu/finance/sptopics/majors/index.html.

EIA – Energy Information Administration (2003a). *Annual Energy Outlook 2003*. Website: http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/ny.html

EIA – Energy Information Administration (2003b). *List of Natural Gas Pipeline New and Expansion Projects.*

EIA – Energy Information Administration (2003c). *Natural Gas Annual 2001.* Washington, DC.

EIA – Energy Information Administration (2003d). *Natural Gas Residential Choice Programs: Status by State as of December 2002.* Website: www.eia.doe.gov/oil_gas/natural_gas/restructure/restructure.html

EIA – Energy Information Administration (2003e). *Retail Unbundling – New York*. Website:

http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/ny.html

IEA – International Energy Agency (2002g). *Energy Policies of the United States: 2002 Review.* Paris.

National Energy Policy Development Group (2001). *National Energy Policy.* Washington, DC.

US Department of Energy (2001). *Update on U.S. Natural Gas Market Trends (October 2001).* Office of Policy and International Affairs. Washington, DC.

VIET NAM

EIA – US Energy Information Administration (2003b). *Vietnam Country Analysis Brief.* Website: www.eia.doe.gov/emeu/cabs/vietnam/html.

Petrovietnam (1997). *Master Plan for Gas Development in Vietnam up to 2010.* Hanoi.

Petrovietnam (2002). Website: www.petrovietnam.com.vn/business/index.htm.