ASIA PACIFIC ENERGY RESEARCH CENTRE

GAS STORAGE IN THE APEC REGION

DEVELOPMENT OF COMMERCIAL STRUCTURE

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FOREWORD

I am pleased to present the final report of the study, Gas Storage in the APEC Region: Development of Commercial Structure. The study is one of the five research projects commenced in 2001.

The objective of the study is to investigate and evaluate where possible the development of a commercial structure in the natural gas storage industry in the context of energy market reforms, and to derive policy implications for the natural gas industry in the APEC region. Due to the differing degrees of market development and to different policy needs across the economies, the degree and scope of commercialisation of gas storage also vary. There is no single model, either in theory or in practice, which can apply to every economy. The report surveys the existing literature and practices as well as new developments in the gas storage business in selected economies. It presents a framework for looking at the commercial business structure around gas storage as a means of enhancing efficiency in the natural gas market. The principal findings of the study are highlighted in the executive summary of this report.

This report is published by APERC as an independent study and does not necessarily reflect the views or policies of the APEC Energy Working Group or of individual member economies. I hope this report will contribute not only to ongoing discussions about the issues explored herein but also to policy formulation for the natural gas sector.

Tatsuo Masuda
President
Asia Pacific Energy Research Centre

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We would like to thank all of those who worked so diligently to produce this report. The development of the study of Gas Storage in the APEC Region could not have been accomplished without the contributions of many individuals and organisations.

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List of Abbreviations

AGA	American Gas Association
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
bcf	billion cubic feet
BOG	boil-off gas
CCGT	combined cycle gas turbine
COS	cost of service
CPC	Chinese Petroleum Corporation (Chinese Taipei)
EDMC	Energy Data and Modelling Centre (Japan)
EEC	European Economic Commission
EGEDA	Expert Group on Energy Data and Analysis
EIA	Energy Information Administration (U.S. Department of Energy)
EU	European Union
EWG	Energy Working Group (APEC)
FERC	Federal Energy Regulatory Commission (US)
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IPP	independent power producer
KEEI	Korea Energy Economics Institute
KEPCO	Korea Electric Power Corporation
KOGAS	Korea Gas Corporation
LDC	local distribution company
LDZ	local distribution zone (UK)
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LRMC	long-run marginal cost
Mcf	million cubic feet
METI	Ministry of Economy, Trade and Industry (Japan)
MMBtu	million British thermal units
MOCIE	Ministry of Commerce, Industry and Energy (Korea)
MOFE	Ministry of Finance and Economy (Korea)
NGTA	New Gas Trading Arrangements (UK)
NTS	National Transmission System (UK)
OCM	On-the-Day Commodity Market (UK)
OECD	Organisation for Economic Co-operation and Development
OMG	Operating Margins Gas (UK)
PGT	Public Gas Transporter (UK)
POSCO	Pohang Steel Company (Korea)
RGTA	Review of Gas Trading Arrangements (UK)
SPA	sales and purchase agreement
SRMC	short-run marginal cost
Taipower	Taiwan Power Company (Chinese Taipei)
tcf	trillion cubic feet
TDR	turn-down ratio
TPA	third-party access
TPES	total primary energy supply
VAT	value-added tax

EXECUTIVE SUMMARY

BACKGROUND AND OBJECTIVES

The natural gas industry has been experiencing large-scale market reforms and has seen a lot of unbundling activities around the world since the 1980s. In addition to the unbundling of gas sales and transport businesses and open access to gas pipelines, the US and the UK have separated gas transport from gas storage, which has traditionally been recognised as part of the gas transport function. One of the most important issues in the course of developing a restructuring plan for the Korean natural gas industry was the ownership and operational structure of LNG storage facilities. This shows that the role of gas storage is changing, and new business opportunities are developing around gas storage under the changing environment of the natural gas industry.

Gas storage has played a traditional role, the so-called utility function, in the gas supply system: seasonal and peak supply-demand matching; optimising transmission network capacity; and providing network security. Particularly in such economies as Japan, Korea, and Chinese Taipei, which depend on imported gas in LNG form, more emphasis has been placed on LNG storage as inventory for feedstock. However, the new commercial role of gas storage is also becoming significant as supply competition is introduced into the gas market. Commercial opportunities in gas storage include gas balancing, gas trading, reducing the burden of take-or-pay; and ensuring security of gas supplies.

Another observation is that a system balancing service is not storable, although gas is storable through diverse plants or technologies such as conventional storage facilities, production swings, the flexibility band of gas pressure in pipes, and interruptible services. System balancing needs change over time and there exists a peak-load pricing problem in the provision of balancing services. Alternatives for system balancing have different cost characteristics. This fact raises the optimal plant mix problem for the system operator, whether it is a public entity or a private one. Enlarging capacity of gas storage facilities and pipelines will make it easier to achieve system balancing, but only at a cost. More interruptible customers may imply low capacity costs to the system operator, but operating costs may be high when consideration is given to costs of fuel switching and possible disruption of operations on the customer's side, meaning outage costs or shortage costs.

In this regard, the study attempts to look at the market for balancing services where gas storage is only one type of technology or plant to produce that service, while it discusses more generally the role of gas storage in the gas supply system and investigates the development of a commercial structure around gas storage services in the context of market reforms. Policy implications will be derived on the gas market in the APEC region.

SCOPE AND STRUCTURE OF THE REPORT

Discussions in the report are based on an overview of the literature on peak-load pricing and optimal plant mix and a survey of the natural gas industry, particularly the gas transport and storage sectors, in selected economies. As it becomes more difficult to collect micro data in an industry becoming more liberalised and operated by private entities, discussions will be more of a descriptive nature rather than providing quantitative analyses.

Policy issues of concern that have been kept in mind in the discussions include, but are not limited to:

- Commercial constraints and resulting commercial incentives
- Implications of interruptible loads for the gas storage industry
- Development of large-volume gas demand and demand-side deregulation
- Supply security and market stability
- Rent sharing and rent dissipation by commercialisation in the gas storage industry

The structure of the report is as follows. Chapter 1 is an introduction to the subject. In Chapter 2, an overview of the physical characteristics and operational roles of gas storage is presented. In Chapter 3, existing business structures for gas storage are discussed. Although the discussion may be focused on those economies that use LNG in their gas systems, there is no good reason why storage business structures should be generically different between gas systems using LNG and those not using LNG. A brief review of the theory of peak-load pricing and optimal plant mix is provided in Chapter 4. Chapter 5 discusses the recent development of more commercialisation in the natural gas storage industry in selected economies. More policy discussions and implications are presented in Chapter 6, and Chapter 7 concludes the report.

MAJOR FINDINGS

THEORETICAL OVERVIEW

Peak-load pricing refers to the pricing of economically non-storable commodities whose demand varies periodically. As such, the literature on peak-load pricing has not paid much attention to the issue of storage.

With storage facilities, less plant, such as fewer pipelines and interruptible loads, will in general be required and peak prices will be lower than otherwise. Consequently, higher welfare benefits can be obtained. In a gas industry with shippers' access to storage and with an established financial market for trading gas, intertemporal optimising behaviour of shippers reduces the volatility of prices and consumption induced by sudden changes in demand and network congestion. It suggests higher welfare through a more competitive and less expensive storage market.

Disregard for the different elements of outage costs can lead to problems, especially since the costs of disruption are known to be considerably higher than the loss in consumer surplus. Hence, ignoring this term would lead to under-investment in capacity.

Transaction costs, notably metering costs, have traditionally been a major concern in the application of peak-load pricing. While metering costs have been reduced significantly, they are still significant for small customers. Thus, some kind of compromise in terms of the number of pricing periods is likely to be inevitable.

FINDINGS FROM EXISTING PRACTICES OF SELECTED ECONOMIES

Deregulation of retail gas markets and customer choice programmes in the US have an impact on the rate at which natural gas storage use becomes more commercialised. The programmes shift some or all of the responsibility for gas supply from the local utility to marketers, sometimes including an unregulated affiliate of the local utility. As the responsibility for supply is shifted, so is the use and control of the assets needed to deliver that supply, including pipeline transport and storage. As a representative case of the bilateral model, where the market is operated on the basis of decentralised bilateral contracts between market participants in every aspect of trading, the US natural gas market has developed a Pareto-improving tool to allow for at least the partial commercialisation of storage assets, the Agency Agreements.

Although not an APEC economy, the UK gas market has had an impact on other gas markets. As a representative case of the poolco model, where a central system/market operator operates the pool of market participants, the UK system relies mainly on the gas supply network of Transco, the largest Public Gas Transporter in the country. Gas storage and other balancing services are traded through the Transco (as system operator) network and the within-day gas commodity is traded through the On-the-Day Commodity Market in which Transco is only one of the gas traders. Unlike most gas systems that do not adopt a market mechanism, in the UK system balancing is required to be consistent with gas trading arrangements so as to support effective competition between gas shippers. There seems to exist a certain merit order of plant dispatch by Transco depending on cost characteristics and market and system conditions, where the same balancing measure is employed differently as market conditions change. LNG and the spot gas market appear to be the most expensive balancing tools.

Japan is considering introducing a third-party access regime to LNG receiving terminals. With a gas system that is regionally divided, dominated by major vertically integrated gas utilities owning pipelines and LNG terminals, and depending heavily on imported LNG, there are many technical issues that need to be resolved. However, more concerns seem to lie in the shift of distribution of rents attached to supply facilities and in changing the balance between supply security and internal market competition.

The history of the Korean gas industry, particularly as seen in the debate between KOGAS and its major customer KEPCO, shows that under-investment in gas supply facilities is likely to occur unless the shortage costs of consumers are appropriately taken into account. As an augmenting device to the required capacity and for the purpose of efficient investment in and operation of a gas supply system, Korea promotes interruptible demands in its new rules of market operation.

Another development in the LNG business in Northeast Asia is that the Chinese Petroleum Corporation of Chinese Taipei diverted nine cargoes to Korea and Japan in the 2000-01 winter season. This raises a question about the possibility of more commercially oriented LNG trade in the region, including the import-export of LNG storage capacity and ship-saving swap deals.

It seems that barriers to commercialisation of gas storage include: the traditional project-business structure of gas development; insufficient commercialisation and competition in the electricity industry; under-development of large interruptible loads, governments' desire to enlarge the market base and to stabilise the market; and governments' concerns about supply security and their desire to maintain influence over the utilities.

POLICY IMPLICATIONS

Policy implications from the study may be summarised as follows:

- Gas storage facilities allow a gas system to function more smoothly with less transport capacity and to moderate peak prices, leading to consumer benefits.

- While large-volume high-load-factor loads should be developed for potential interruptible customers for system security, the interruption costs incurred by them must be properly reflected in the tariff structure.

- Whether a gas market is based on a bilateral or poolco model, more liberalisation of the market seems to facilitate development of a commercial structure of the gas storage industry.

- A commercial business structure implies competition for balancing services between system operators and system users, and competition among diverse balancing tools. Hence, policy-makers need to ensure that the market strikes a balance between costs to the system operator and those to system users and that diverse system balancing tools compete according to their cost characteristics. These cost characteristics are best realised in a market where gas and capacities are traded on a commercial basis.

- There often exist trade-offs between efficiencies in a market and other policy objectives, equity and energy security in particular, that government attempts to achieve through and within the market in question. Achieving energy security through gas stockpiling does not seem to justify costs under current technology unless risk premiums for gas supply disruption are extremely high.

CONCLUSIONS AND FURTHER STUDY

Theory tells us that we should adopt more attributes of peak-load pricing in the industry, whether it is operated by a public entity or by private participants. Practices in some economies indicate that adopting peak-load pricing will lead to reduced storage requirements, that existing storage capacities are utilised more efficiently, and that market participants are finding new ways of sharing rents in storage capacities.

In addition to the discussion of rent dissipation at a fundamental level, there are specific issues that await further study. One concerns possible changes in the role of LNG storage in the context of regional interconnection of gas pipelines in Northeast Asia. Topics that ought to be studied include: the border price of pipeline natural gas, changing inventory turnovers of LNG tanks and cost implications, and resulting load coverage between LNG and pipeline natural gas. Related to this is the effect of the existence of indigenous production on the development of a competitive internal market. As regional energy market integration is being discussed, trading of storage capacity across economies in broader terms, including LNG ship swapping deals and LNG traders' participation, may well have a large impact on the trading arrangements of LNG in the region.

Until now, it has been assumed that, with storage included in peak-load pricing, discussion of it is a bit limited, since storage has been regarded only as part of gas transport. But storage services may be treated in the framework of peak-load pricing, as the gas storage business is now recognised as an independent industry. For example, given the coexistence of market and traditional utilities to match supply and demand for gas and capacities, shippers or system users and a system operator may be regarded as competing for balancing tools. As another example, if an interruptible customer is considered to supply a balancing service to a system operator and if the system operator is to buy the service, the role of storage in gas supply may be analysed from a different perspective. That is, use and expansion of the gas supply system in a liberalised market may be modelled in terms of a competitive market where both traditional utilities and system users are both consumers and suppliers of gas and capacities. It will involve a different look at the same issue and new preference structures for the system operator and the traditional consumer including their risk aversion, but is likely to provide new insights in the discussion of storage and peak-load pricing.

CHAPTER 1

INTRODUCTION

The thrust of energy market reforms is to restructure the trading arrangements of energy commodities and services so that various value-adding components can receive correct prices for their value and cost drivers pay correct prices. By doing so, it is argued, both suppliers and consumers will react to the correct price signal, resulting in efficient production, transport and consumption of energy as well as the market providing energy security. One of the important factors that have made market reforms possible is the technological development in metering and information transfer. This has contributed much in lowering the transaction cost involved in the energy chain, and based on this some developed economies have adopted a strategy of unbundling energy supply functions.

The natural gas industry has been no exception in this regard and it has seen a lot of unbundling activities around the world since the 1980s. In addition to the unbundling of gas sales and transport businesses and open access to gas pipelines, the US and the UK have separated gas transport from gas storage, which has traditionally been recognised as part of the gas transport function. In these economies, a new form of gas storage service is in operation, virtual storage, which does not require physical storage facilities. One of the most important issues in the course of developing a restructuring plan for the Korean natural gas industry was the ownership and operational structure of LNG storage facilities. These facts clearly show that the role of gas storage changes, and new business opportunities are developing around gas storage under the changing environment of the natural gas industry – market reforms and technological progress.

Gas storage has played traditional roles in the gas supply system: seasonal and peak supply-demand matching; optimising transmission network capacity; and providing network security. Particularly in such economies as Japan, Korea and Chinese Taipei, which depend on imported gas in LNG form, more emphasis has been placed on LNG storage as inventory of feedstock. However, the new commercial role of gas storage is also becoming significant as supply competition is introduced in the gas market. Commercial opportunities in gas storage include gas balancing, gas trading, reducing the burden of take-or-pay, and providing security of gas supply.[1]

Examples of the factors that make the roles of gas storage minor in system operation are: high system load factor due to small seasonal consumption variation, consumer composition biased towards power generators using gas as a base load fuel; a large volume of line pack compared with demand or high network security in the absence of gas storage; and underdevelopment of a competitive gas market. But as more low-load factor consumers have access to the network, as demand grows, as more diverse market players participate in the gas market, and as decision-making gets more market-based, gas storage will play a greater role commercially as well as physically.

Another observation about gas storage in the context of system operation and commercial business structure is this: gas is storable, whereas electricity is not. For this reason, most discussions of optimal plant mix have taken place for electricity. It should be noted that system-balancing service is not storable, although gas is storable through diverse plants or technologies such as conventional storage facilities, production swing, flexibility band of gas pressure in pipes, and interruptible services. System balancing needs to change in time and there exists a peak-load

[1] Gas inputs are required to balance with gas outputs within a reasonable bandwidth of pressure for efficiency and safety of any gas transport system. As gas markets become competitive and the burden of periodical gas balancing comes to lie with system users, the value of the flexibility provided by gas storage increases. Similar reasoning applies to other services. See the section below on pages 11 to 14 for the functions of gas storage.

pricing problem in the provision of balancing service. Alternatives for system balancing have different cost characteristics. This raises the optimal plant mix problem to the system operator, whether the operator is a public entity or a private one. Greater capacity of gas storage facilities and pipelines will make it easier to achieve system balancing, but only at a cost. More interruptible customers may imply low capacity costs to the system operator, but operating costs may be high when consideration is given to costs of fuel switching and possible disruption of operation on the customer side, that is, outage costs or shortage costs.

In this regard, the study attempts to look at the market for balancing service where gas storage is only one type of technology or plant to produce that service, while it discusses more generally the role of gas storage in the gas supply system and investigates the development of a commercial structure around gas storage services in the context of market reforms. Policy implications will be derived on the gas market in the APEC region, extending to possible differing types of ownership structure of storage facilities, such as public or private, and regulatory options for the service.

Before proceeding, it may be useful to raise some issues and questions regarding gas storage, and some related to the energy market in general. These particularly concern the world trend of energy market reform. This report cannot answer all of them but will attempt to discuss some of them and leave open the remaining issues to future discussion. They are:

- Commercial constraints that have been and will be effective in inducing market participants to behave efficiently
- Structural barriers that limit the development of a commercial structure of natural gas storage and transport
- Implications of interruptible loads for the gas storage industry
- Development of large-volume gas demands and demand-side deregulation
- Supply security and market stability implications of a commercialised storage industry
- Rent sharing and rent dissipation by commercialisation in the gas storage industry
- Possibility and benefits of regional LNG markets and storage capacity trading
- Changing role and cost implications of LNG storage resulting from the introduction of pipeline natural gas

The structure of the report is as follows: The next chapter looks at what gas storage is, presenting an overview of the physical characteristics and operational roles of gas storage. In Chapter 3, the existing business structures for gas storage are discussed. The discussion may seem focused on those economies that use LNG in their gas system, although there is no reason why storage business structures should be generically different between gas systems using LNG and those not using LNG. The theory of peak-load pricing and optimal plant mix is summarised in Chapter 4. In Chapter 5, diverse market participants in the gas storage industry are discussed, looking at the US, with different system operation practices discussed for the UK and Korea, although the roles of LNG facilities are different between the two economies. Some policy issues on the development of commercial and more efficient business structure for gas storage are presented in Chapter 6. Chapter 7 concludes the report

CHAPTER 2

WHAT IS GAS STORAGE?

INTRODUCTION

What is gas storage and why is it important? One may answer that gas storage means a facility where there is gas and in which gas can be stored. But the correct answer is not so simple as can be expressed in a single sentence, partly because when we talk about gas storage we are normally referring to the storage service that is provided by storage facilities, not the storage facilities themselves. However, things will become clear if we think about the roles, functions or uses of gas storage in a gas supply system and in a gas market. What gas storage does, regardless of its physical characteristics, is to act as a kind of warehouse. Without a warehouse, production must match demand at all times if the price of the commodity in question is to remain constant. In other words, to the extent that production, not supply, does not match demand, prices will fluctuate, other things being equal.

At an extreme, citizens of an economy like Korea, where there is no natural gas production, will be denied access to natural gas without LNG storage facilities, apart from price fluctuations of natural gas. Of course, this argument from the perspective of accessibility is not applicable to all gas systems, since the LNG storage facilities in Korea play more the role of inventory of production feedstock. However, to the extent that natural gas storage functions as a warehouse, an inability to have LNG storage facilities and a denial of access to natural gas could be interpreted as the economic cost of natural gas being prohibitively high for potential customers.

It is well known that electricity is not economically storable, although a negligible amount of total demand can be met by batteries. For this reason, electricity generation plants and transmission and distribution networks must be constructed to meet certain demands at any given point in time. Because of its non-storability and the resultant need to secure sufficient production and transport capacity in both peak and off-peak periods, electricity commands high (average) prices compared with other types of energy, apart from the low thermal efficiency of electricity generation. This is the core of the peak-load pricing problem in electricity.

Unlike electricity, gas is storable to a limited extent. It is a fact that with storage facilities, fewer production and transport plants will in general be used and peak prices will be lower than otherwise, and considerable welfare benefits can be obtained. In this sense, even though natural gas requires huge amounts of capital investment and operating costs to be supplied to customers, the price that customers actually pay may be said to be much lower than if it was not storable.

Natural gas storage is a kind of buffer in a gas supply system. Without a buffer, an energy supply system can easily break down by an internal or external shock, which translates into a vast economic cost. Because electricity is not storable, an electricity supply system should maintain a certain amount of generation reserve margins. However, since natural gas is storable in storage facilities as well as in pipelines, a natural gas supply system is relatively flexible to internal and external shocks. Although a direct comparison of the benefits and costs of flexibility between electricity and natural gas is impossible, it may be argued that the gains from system security obtained from storability are enormous.

As the generic service which natural gas storage facilities provide is flexibility, which is valuable in an expensive gas supply network, more profitable business opportunities are being developed in the gas storage business, as the natural gas market becomes liberalised and gas supply functions are unbundled. More independent storage developers and operators enter the market and the gas storage business becomes an independent segment of the gas supply industry. To reflect this trend, new terms have been forged such as gas storage industry and gas storage market.

PHYSICAL STRUCTURES OF GAS STORAGE

In this section, the physical characteristics of natural gas storage will be briefly described to provide a foundation for a discussion of the natural gas storage business. Principal types of natural gas storage are: depleted oil/gas field reservoirs, salt caverns/cavities, aquifers, and liquefied natural gas storage. Abandoned mines can be reconditioned as gas storage facilities. Each type has its own characteristics, such as porosity, permeability and retention capability, which govern its suitability and economics to particular applications. Also, site preparation costs, deliverability and cycling capability affect the economics of a particular type and site of storage facilities.

DEPLETED FIELD RESERVOIRS

Gas can be stored in depleted gas or oil field reservoirs. Conversion of a field to storage takes advantage of existing wells, gathering systems and pipeline connections, so that it is generally the least expensive type of storage facility to develop per unit of space or working gas.[2] While the working gas capacity of depleted fields tends to be larger than that of other types of storage facilities, injection and deliverability rates are typically low relative to size. For this reason, depleted fields are normally used for seasonal storage rather than peak-shaving storage.

AQUIFER RESERVOIRS

Aquifers are underground water reservoirs situated in similar geological formations to oil and gas fields. An aquifer is suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. Typically, it is more expensive to construct and operate than depleted fields because it requires high-cost drilling, more cushion gas (because it has no original gas), and greater monitoring of injection and withdrawal performance. It is known that the cost of cushion gas amounts to 30-50 percent of the investment cost of underground storage facilities and is higher for aquifer storage facilities.[3] Deliverability can be enhanced by the presence of an active water drive. Due to its low deliverability, aquifer storage is used for seasonal and strategic storage, and is generally developed only in areas where there are few suitable alternatives.

SALT CAVITIES

Salt cavities or salt caverns are developed in underground salt formations by a leaching process. A well is drilled through which water is simultaneously pumped in and out via concentric pipes. The salt dissolves in the water, forming an underground cavity. Salt cavities take advantage of the high volume, although typically smaller than depleted fields, high injection and deliverability, and flexible operations capability. Base gas requirements are relatively low. Development of salt cavities is more costly than depleted field conversions on a unit working gas capacity basis. However, their multi-cycle operations capability reduces per-unit cost of a given volume of gas injected and withdrawn.

As reference, some key parameters are given in the following tables for underground natural gas storage.

[2] See below for the storage measures.

[3] Information Centre for Petroleum Exploration and Production [2001]

Table 1 Economic Characteristics of Underground Storage

	Depleted Field	Aquifer	Salt Cavity
Working Gas (mill m^3)	300~5,000	200~3,000	50~500
Investment Cost per Unit Working Gas (US$/$m^3$)	0.05~0.25	0.3~0.5	0.4~0.7
Operating Cost (US$/MMBtu)	0.3~0.5	0.3~0.5	0.3~2.5[1)]

Note: 1) Depending on working gas turnovers over the year.

Source: CEDIGAZ [1995].

Table 2 Main Parameters of Underground Storage in Europe and Central Asia

	Depleted Fields	Aquifer	Salt Cavity
Total Working Gas Ratio to Total Capacity (%)	16.7~74.6 (57.1)	20.0~57.1 (43.4)	50.0~88.6 (68.7)
Deliverability (10^6 m^3/day)[1)]	0.02~3.90 (0.37)	0.07~1.44 (0.35)	0.53~4.5 (1.58)
Withdrawal Period (days)[2)]	22~185 (132)	23~144 (80)	2~42 (25)

Note: 1) Figures are on a per-well basis for depleted fields and on a per-cavity basis for salt cavities.
2) It refers to the total working gas volume divided by deliverability, namely, the minimum time required to withdraw all working gas. It is also called duration.
3) Figures in parentheses denote averages.

Source: United Nations Economic Commission for Europe [2001].

LNG STORAGE

Natural gas can be liquefied at below minus 160°C and can be stored in a tank specially designed and constructed to tolerate the low and highly variable temperature. If 600m^3 of natural gas is liquefied at atmospheric pressure, it yields 1m^3 of LNG.

If gas storage needs are moderate or if the nature of the subsoil does not allow the building of an underground storage facility in a high-demand area, the solution may lie in constructing an LNG facility. One or more LNG tanks can be coupled with a liquefaction plant that works during periods of low demand and a regasification unit that is used for peak-shaving supply. LNG facilities typically offer the greatest deliverability, relative to size, of any form of gas storage. However, gas liquefaction is expensive and time-consuming, typically leading to it being used for peak-shaving purposes.

Many economies with less indigenous natural gas production employ LNG vessels to meet their gas needs. Examples include Japan, Korea and Chinese Taipei in Northeast Asia, and France, Italy, Portugal and Spain in Europe. At the end of the chain, LNG is regasified and supplied through pipeline systems. LNG receiving terminals include storage tanks and are often on a larger scale than LNG plants in gas-producing areas. The reason for the large scale, apart from the sheer size of demand, is the requirement to satisfy fluctuating demand and to accommodate facilities for regasification and other preparatory work for supply to end-users.

The LNG produced in a peak-shaving unit or stored in an LNG receiving terminal can be used to supply a storage and regasification satellite by tank lorry. The satellite unit can then feed a small isolated network.

ALTERNATIVES TO GAS STORAGE

There are a number of alternatives that perform similar functions to gas storage. One is swing gas, which refers to gas supplied in varying volume in response to requests from purchasers. A swing factor is typically specified in a gas sales-purchase agreement. It serves as an alternative to seasonal storage. Another alternative is spot gas. Shippers can buy this flexibility on the spot market. However, they have to face price risk, since the spot price can fluctuate sharply according to system stress. Interruptible loads, a third alternative to storage, perform two different roles depending on different perspectives. From the system operator's perspective, it plays the role of resolving local transmission constraints by reducing demand in a particular area, which is an alternative to strategic storage facilities at the extremities of the gas system. From the perspective of shippers, interruptible customers can be used as a daily balancing tool or trading tool playing the role of peak-shaving storage and in some cases the role of seasonal storage. Linepack refers to the gas in the pipes, and due to the inherent flexibility of pipe pressure within certain limits it can function as an alternative to storage. The trend in liberalised markets is for linepack to be provided as a separate service, as opposed to the traditional practice of selling it as bundled service as part of transport.

VIRTUAL STORAGE

Virtual storage refers to the provision of a service similar to physical storage but does not require the service provider to keep physical storage capacity. That is, a virtual storage provider offers a storage service and supports this service through swing gas, spot market deals, some physical storage and risk management tools. This type of storage service has become popular in the US and is being developed in the UK gas market.

STORAGE MEASURES

There are several storage measures that are used to describe physical capabilities of storage facilities.[4] Total capacity is the maximum volume of gas that can be stored in an underground storage facility and is determined by the physical characteristics of the reservoir. Base gas refers to the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability throughout withdrawal. It is also called cushion gas. Working gas capacity is defined as total capacity minus base gas. Working gas is the volume of gas in the reservoir above the designed level of the base gas. It is that which is available to the market place. In the UK it is termed space for both underground storage facilities and LNG facilities. Injection refers to the maximum volume of gas that can be injected into storage in one day. Deliverability refers to the maximum volume of gas that can be delivered or withdrawn from storage in one day. It is also called deliverability rate, withdrawal rate, or withdrawal capacity. Turn-around refers to the capability to reverse injection and withdrawal operations at a storage facility. Typical reservoir facilities may require several days to reroute gas flows, while most cavern facilities can reverse flow in 10 to 30 minutes.

The deliverability of a facility is variable depending on such factors as the amount of gas in storage at any particular time, the pressure within the storage, compression capability available to the storage, and the configuration and capabilities of other facilities associated with the storage. In

[4] They are drawn from the Energy Information Administration [2001].

general, a storage facility's deliverability varies with the amount of base gas and working gas in storage: it is at its highest when the storage is most full and declines as working gas is withdrawn.

The commercial success of storage in a deregulated gas market depends on deliverability of gas to the market and turn-around capability rather than on (total) working gas capacity. Storage operators need to be able to inject and withdraw gas quickly to react to highly volatile gas prices. Consequently, salt cavern facilities have become increasingly popular among storage operators in the US. Because there is no resistance in a salt cavern, gas can flow into and out of the cavern readily. It is reported that the operator of an average salt cavern is able to withdraw all its gas in 10 to 11 days and refill it in only 20 days, compared with nearly 60 days to withdraw all gas from traditional depleted gas reservoir facilities.[5]

FUNCTIONS OF GAS STORAGE

TRADITIONAL UTILITY FUNCTIONS

Gas storage has traditionally played three roles in the gas supply system: seasonal and peak supply-demand matching; optimising transport network capacity; and providing network security.[6] These traditional system operation functions of gas storage are sometimes referred to as utility functions.[7] However, as natural gas becomes available in LNG form for transport and storage purposes, particularly in markets where there is no production or insufficient production as in Japan, Korea and Chinese Taipei, the role of inventory of feedstock, which can be compared to production reservoirs, has also been important in those markets.

Gas storage can be used to ensure a match between available supply and demand on cold days. Storage to meet additional demand during cold weather generally takes two forms. One is seasonal storage, which enables delivery of a large volume of gas over an extended period of time to ensure supply-demand matching throughout the winter. The other is peak-shaving storage, which makes it possible to deliver gas over a short period of time to cover needle peaks.

Gas storage can be used as an alternative to investment in transport capacity. In economies where there are only a small number of very cold winter days a year and gas has penetrated the space heating market, a large volume of pipeline capacity is needed to meet demand. However, an alternative to this high volume of pipeline capacity is to locate peak-shaving storage facilities at the extremities of the pipeline system, reducing the required pipeline capacity. Gas may be injected into storage facilities when demand is low and there is spare capacity of pipelines. And gas can be withdrawn from storage when available gas or pipeline capacity cannot meet demand. This kind of storage capacity also allows the pipeline system to operate at a higher load factor. In the US, more storage facilities are being built at such strategic locations as market hubs as well as city gates. It is reported that intelligent use of gas storage can create significant throughput capacity for the transport grid at a capital cost of one to two percent of that of the next-cheapest alternative. Approximately $0.5 billion invested in a system of hubs with high deliverability salt caverns can displace $40-80 billion of incremental expansion in the existing pipeline infrastructure.[8]

As mentioned previously, the basic function of gas storage facilities is to provide flexibility to the gas supply system. As such, another traditional role of gas storage is to provide network security. Gas supply can be adversely affected by a number of factors, including offshore supply failures, onshore supply failures such as pipeline fractures and compression failures, and demand

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[5] See Energy Information Administration [1995].

[6] This categorisation follows Madden and White [1999]. This section also draws on their discussion.

[7] See, for example, American Gas Association [2001].

[8] See, for example, Bickle [1996].

forecast errors. Gas storage can be utilised to manage unanticipated shortages of gas or pipeline capacity. Having enough LNG storage capacity is very important for those economies that import natural gas in LNG form, since a gas system using LNG as feedstock is more rigid than one using pipeline gas in terms of inventory management. In this regard, sizable gas storage facilities provide strategic supply security in the event of an extended supply interruption.

NEWLY DEVELOPING COMMERCIAL FUNCTIONS

The introduction of supply competition along with unbundling of pipeline transport in such economies as the US and the UK has led to the development of a commercial role for gas storage. The unbundling of transport from gas sales has improved price discovery at various points on the pipeline system, as diverse services are provided separately, unlike in the past. In particular, storage facilities have increasingly been used to extract profits by, for example, location- and time-based arbitrage. Storage operators take advantage of swings in spot prices by selling gas at high prices and buying at low prices. These transactions benefit market participants through greater availability and more efficient pricing of natural gas.

In the US, transactions in the wholesale market have gradually moved from wellheads and consumption areas to hubs at major interconnections of interstate and intrastate pipelines. Hubs were formed and are typically operated by one or several interstate pipeline companies that own the pipelines interconnected at the hub. Hubs allow market participants to acquire gas from several independent sources and ship it to several different markets. This eliminates the need to contract natural gas and pipeline capacity all the way from the wellhead to the consumption site. Instead, shippers can combine supply routes across several hubs to diversify supply risks. Hub operators have increased the scope of hub services from the physical transfer of gas to storage, processing, and trading. The variety of services has led even more shippers to use hubs for transport and acquisition of natural gas. The introduction of electronic trading systems has helped the separation of trading from physical infrastructure and led to the development of market centres connected to one or several hubs by electronic networks.

In general, areas where the use of gas storage offers commercial opportunities include gas balancing, gas trading, mitigating take-or-pay constraint, and providing security of gas supplies.

GAS BALANCING

As competitive gas supply markets generally require a certain form of periodical balancing and the gas supply systems in the US and the UK adopt a daily balancing regime, the value of the flexibility provided by gas storage has increased. The imbalance penalties make gas storage a valuable option for gas shippers as it can provide a degree of protection against balancing costs. Typical storage services for this purpose include parking and loaning.

GAS TRADING

Gas storage has become a gas-trading tool as gas commodity markets are developed. Shippers can buy spot gas in summer when it is cheap, inject it into storage, and sell it in winter when it is likely to command a premium. Shippers can lock in this price arbitrage opportunity by combining storage and futures trades. Multi-cycle storage facilities allow shippers the opportunity for daily arbitrage.

MITIGATING TAKE-OR-PAY CONSTRAINT

Gas storage helps to resolve at least temporary oversupply problems from one year to the next. This is especially true for such economies as Korea, Japan and Chinese Taipei that depend on LNG for most of their natural gas needs. If a gas supplier has purchased gas in anticipation of increasing demand under a take-or-pay obligation, but the actual demand has turned out to be less than expected, the surplus can be put into storage in the hope that gas demand may be greater the following year. The volume of injected gas will depend on the non-take penalty and the storage costs. In the long run, these costs affect the expansion of storage capacity.

PROVIDING SECURITY TO INSECURE GAS SUPPLIES

As the gas market expands to the global level, more gas supplies are coming from long-distance sources. As the long distances and routes that the gas travels are sometimes translated into diverse risks, political as well as operational, storage capacity in consuming areas or economies becomes more valuable. On the one hand strategic storage is valuable in this context, and on the other such high-risk gas will sell at a discount in a competitive gas market. A gas marketer with storage capacity in hand may buy cheap gas from a potentially insecure source and sell it at a premium in return for the security that is added. At the national level, consumers of gas-importing economies may consume cheap insecure gas or may pay for higher security by buying secure gas or by installing more storage facilities and storing enough gas.

Some of the terms that are used in the US gas market are presented below (see box).

MARKET CENTRE AND HUB SERVICES

Wheeling: Essentially a transport service. Transfer of gas from one interconnected pipeline to another through a header (hub), by displacement (including exchanges), or by physical transfer over a market centre pipeline.

Parking: A short-term transaction in which the market centre holds the shipper's gas for redelivery at a later date. Often uses storage facilities, but may also use displacement or variations in line pack.

Loaning: A short-term advance of gas to a shipper by a market centre that is repaid in kind by the shipper a short time later. Also referred to as advancing, drafting, reverse parking and imbalance resolution.

Storage: Storage that is longer than parking, such as seasonal storage. Injection and withdrawal operations may be separately charged for.

Peaking: Short-term (usually less than a day and perhaps hourly) sales of gas to meet unanticipated increases in demand or shortages of gas experienced by the buyer.

Balancing: A short-term interruptible arrangement to cover a temporary imbalance. The service is often provided in conjunction with parking and loaning.

Gas Sales: Sales of gas that are used mainly to satisfy the customer's anticipated load requirements or sales obligation to others. Gas sales are also listed as a service for any market centre that is a transaction point for electronic gas trading.

Title Transfer: A service in which changes in ownership of a specific gas package are recorded by the market centre. Title may transfer several times for some gas before it leaves the centre. The service is merely an accounting or documentation of title transfers that may be done electronically, by hard copy, or both.

Electronic Trading: Trading systems that either electronically match buyers with sellers or facilitate direct negotiation for legally binding transactions. A market centre or other transaction point serves as the location where gas is transferred from buyer to seller. Customers may connect with the hub electronically to enter gas nominations, examine their account position, and access e-mail and bulletin board services.

Administration: Assistance to shippers with the administrative aspects of gas transfers, such as nominations and confirmations.

Compression: Provision of compression as a separate service. If compression is bundled with transport, it is not a separate service.

Risk Management: Services that relate to reducing the risk of price changes to gas buyers and sellers, for example exchange of futures for physicals.

Hub-to-Hub Transfers: Arranging simultaneous receipt of a customer's gas into a connection associated with one centre and an instantaneous delivery at a distant connection associated with another centre. It is a form of 'exchange' transaction.

Source: Energy Information Administration, *Natural Gas 1996: Issues and Trends*, p. 71.

Note: Definitions were obtained from the FERC's Office of Economic Policy. Some terms do not apply to the UK market.

CHAPTER 3

NATURAL GAS BUSINESS STRUCTURE IN SELECTED ECONOMIES

THE UNITED STATES

In 2000, the United States was both the biggest consumer and the biggest producer of natural gas. It consumed 22.7 tcf of natural gas, produced 19.1 tcf, and imported (net) around 3.5 tcf. Market reform activity focused on the deregulation of natural gas has made great progress since 1985, formulating a new regime in the natural gas industry.

NATURAL GAS DEMAND AND SUPPLY

The consumption of natural gas in the United States accounted for about 27 percent of total world consumption of natural gas in 2000, and represented 24 percent of the energy consumed in the US. The average winter temperature and natural gas prices are the most important factors affecting the consumption level of natural gas. The residential and commercial sectors are the most sensitive to temperature. About 70 percent of annual residential gas consumption occurs during the winter months, from November to March, which represents 41 percent of the calendar year. In the peak consumption month, typically January, residential consumption typically reaches or exceeds industrial consumption. About 62 percent of total annual consumption in the commercial sector occurs during the winter months. The use of natural gas for electricity generation typically peaks in the summer months, when air conditioning demand is high.

Production of natural gas in the United States in 2000 accounted for 22.9 percent of the world total and represented 27 percent of US energy production. Natural gas prices affect domestic gas production. Recent gas production patterns show the impact of a lengthy period of low gas and oil prices, which had turned around by mid-1999. In response to the relatively low gas and oil prices, gas production in 1999 hit a recent low of 18.6 tcf. Incremental gas consumption requirements that year were satisfied by increased imports and a drawdown from storage. As demand for gas diminished, prices also weakened, leading to a falloff in gas rig activity from a relative peak of 657 rigs drilling gas wells as of December 19, 1997, to 362 as of April 23, 1999.

Despite the recent comeback of gas and oil prices, new production of gas has been meagre. It is reported that while there were 1,065 rigs drilling in 2001, declining gas yields in the fields are not enough to meet demand. Over the past several years, the United States has experienced a widening gap between production and consumption. It consumed 18 percent more than it produced in 2000 with the difference made up with imports largely from Canada through pipelines. Mexico also supplied natural gas to the United States via pipeline, and LNG was imported from Algeria, the United Arab Emirates, Australia, Qatar, Trinidad and Tobago, Malaysia, Nigeria, Oman and Indonesia. Net imports accounted for 16 percent of total consumption in 2000. With tight domestic supplies and growing demand, imports are an important source of supplemental supply.

The United States is a net importer of natural gas from Canada, which provided 94 percent of total US imports in 2000. The weighted average price of gas imports from Canada in 2000 was approximately $3.90 per MMBtu, around 20 percent lower than the average city gate price in the United States. The United States is a net exporter of natural gas to Mexico. While exporting 110 bcf to Mexico through pipelines, it imported approximately 6 bcf of natural gas from Mexico in 2000. To meet the increasing demand for gas in Mexico, investments in infrastructure for export from Texas, California and Arizona have grown rapidly. The majority of new cross-border pipeline projects have been designed to supply natural gas to Mexico's power producers.

LNG imports continued their robust growth in 2000 to a total of 220 bcf. As of September

2001, the continental United States had three operational LNG receiving terminals, at Everett in Massachusetts, Lake Charles in Louisiana, and Elba Island in Georgia. Imports into Everett totalled 99 bcf in 2000. Almost 81 percent of the imports received in Everett came from the Trinidad project, primarily under long-term contracts. The Lake Charles facility received 124 bcf. Many of the shipments to Lake Charles were spot purchases. Algeria delivered to both facilities, primarily under long-term arrangements.

DEREGULATION AND STRUCTURAL CHANGE

In the United States, deregulation of transactions in the gas industry was launched in 1978, when the Natural Gas Policy Act to liberalise the interstate natural gas market was adopted by Congress. After that, Congress approved legislation liberalising wellhead gas prices in 1989 and legislation freeing up interstate natural gas transactions in 1992. In addition to legislation, the Federal Energy Regulatory Commission (FERC) has introduced a set of executive orders over the last 20 years that gradually established a regime for market forces to determine resource allocations in the natural gas industry.

Of all the Orders issued by the FERC, Order No. 636 introduced the most radical regulatory change in the gas industry. It required pipeline companies to use third-party transport activities and to set up separate transport and trading affiliates. This helped the formulation and development of natural gas marketing, and supply competition was introduced in the natural gas industry. The regulation of interstate pipeline transport was reformed to promote fair rates and minimise regulation of natural gas prices. It allowed resale of transport contracts by shippers, and a secondary transport market was created. Shippers can purchase pipeline capacity from other shippers that have spare capacity temporarily or permanently. The secondary transport market promotes efficient allocation of transport contracts among shippers and high utilisation of natural gas pipelines.

Deregulation has changed profoundly the structure of the natural gas industry in the United States, where 1985 was the watershed. Before 1985, the gas industry was vertically separated into production, pipeline transport and distribution. All transactions were strictly regulated and completed under long-term contracts so that the industry was de facto vertically integrated. Distribution companies could not choose a pipeline company freely. There was little competition among gas producers.

After 1985, with the introduction of open access to interstate pipeline transport, local distribution companies and large end-users connect directly with interstate pipelines, and contract natural gas directly from producers. Many large end-users constructed new connecting pipelines to bypass local distribution companies and gain access to the wholesale market. The unbundling of interstate pipeline transport in 1992 completed the transformation of a wholesale market into a fully competitive market.

NATURAL GAS MARKET

The US natural gas market is composed primarily of producers, pipeline companies, storage companies, local distribution companies (LDCs), marketers and end-users. Competitive wholesale gas market trading is implemented through bilateral decentralised transactions among the participants in the natural gas industry, including producers, marketers, LDCs and large end-users. Trading concentrates in spot markets in producing regions and consuming areas. These spot markets generate efficient price signals about the market value of natural gas, instantly reacting to actual and expected changes in supply and demand.

Deregulation of the gas industry has facilitated the separation of physical and financial trading. Gas market participants minimise supply risks by balancing their demand with gas supply contracts. They minimise price risks by taking financial positions on their gas supply contract portfolio. As a result, both a physical gas market and a financial gas market have developed in the wholesale natural gas market

The physical wholesale gas market in the United States is very competitive. Both the supply and demand sides of the market involve participants from all segments of the industry. Producers, pipelines, marketers, LDCs and large end-users both buy and sell positions to minimise the costs and risks of natural gas supply. Transactions are concluded on a bilateral basis between market participants; many of them involve intermediation by gas marketers. Most natural gas trading takes place in spot markets organised by market centres and hubs and facilitated by electronic trading systems.

Natural gas is traded through bilateral gas contracts which specify the conditions of delivery, including volume, price, calorific value, and location, time and duration of delivery. The contracts are divided into three types: long-term, medium-term and short-term. A long-term gas contract for more than 18 months specifies a fixed quantity of gas to be delivered on a monthly basis. A medium-term gas contract covers gas delivery for up to 18 months, but most are for a year or less, specifying the volume of monthly or daily gas deliveries, including allowed variation. A short-term contract is for one month, traded in natural gas spot markets. It specifies a fixed price for natural gas that is equal to the prevailing market price at the time of contract completion.

Traditionally bilateral, transactions now often involve intermediation by natural gas marketers. Marketers aggregate the demand of many end-users and small distribution companies and trade natural gas on their behalf, reducing the cost of transactions in the natural gas market. The concentration of trading in market centres and hubs has led to the development of natural gas spot markets. And the introduction of electronic information systems has promoted electronic trading in the spot markets.

With deregulation of the gas industry, industry participants look for ways to minimise price risk through financial instruments, and markets respond by offering financial gas contracts used for hedging, speculation and arbitrage. Financial gas contracts are used to manage two types of risk in the natural gas market − price and basis risk. Price risk is generated by the volatile spot market prices of natural gas. Basis risk is the risk of change in the price differential between locations, time periods and qualities of gas deliveries and between natural gas and other commodities.

There are seven major types of financial gas contracts in the United States: futures contract, forward contract, swap, hedge, options contract, exchange of futures for physicals, and alternative delivery procedure. Each uses different techniques to manage price and basis risk.

THE NEW ROLE FOR STORAGE

Traditionally, natural gas storage has played an important role in ensuring adequate gas supplies, in particular for seasonal and peak gas demand during heating seasons and to balance pipeline operations on a daily basis.

There are three principal types of underground gas storage facilities in the United States: depleted fields; aquifer reservoirs; and salt caverns (see Table 3). A storage facility's daily deliverability or withdrawal capability is the amount of gas that can be withdrawn from it in a 24-hour period. Gas can also be stored as LNG. LNG storage facilities are usually associated with distribution companies. LNG storage is especially suited for LDC to meet delivery requirements, especially during times of peak demand.

The new role for gas storage is to promote efficient transactions in the deregulated natural gas market. The industry having been deregulated, more attention needs to be paid to cost efficiency. One of the most important outcomes of deregulation has been that the price of natural gas has become more volatile, implying higher price risks for market participants. Storage can take advantage of swings in spot prices by selling natural gas at high prices and buying at low prices in the spot market, and facilitate higher utilisation of pipeline capacity.

The reform of the natural gas market in the United States has achieved much in the past 15 years. Market forces bring competition into the natural gas industry, guide individual transactions and search for the socially optimal outcome. The participants have benefited from the competitive and efficient markets, including both the wholesale natural gas market and the interstate transport market. Most consumers of natural gas are believed to pay less for gas due to deregulation. Table 4 gives a general idea of price reductions following deregulation.

Table 3 Summary of Underground and LNG Storage in the U.S., 2000

	Region	East	West	Producing	Total
Depleted Gas/Oil Fields	Sites	243	31	74	348
	Working Gas Capacity (bcf)	1,690	590	1,089	3,368
	Daily Deliverability (Mcf/d)	31,888	8,620	17,166	57,674
Aquifer Storage	Sites	33	6	1	40
	Working Gas Capacity (bcf)	351	39	1	392
	Daily Deliverability (Mcf/d)	7,457	1,175	12	8,644
Salt Cavern Storage	Sites	4	0	23	27
	Working Gas Capacity (bcf)	4	0	135	139
	Daily Deliverability (Mcf/d)	298	0	11,118	11,416
Total	Sites	280	37	98	415
	Working Gas Capacity (bcf)	2,045	628	1,226	3,899
	Daily Deliverability (Mcf/d)	39,643	9,795	28,296	77,734
LNG Facilities	Sites	83	13	3	99
	Working Gas Capacity (bcf)	73	12	7	92
	Daily Deliverability (Mcf/d)	10,135	1,186	312	11,633

Note: Regions are those established by the American Gas Association.

Source: Reproduced from Tobin and Thompson [2001].

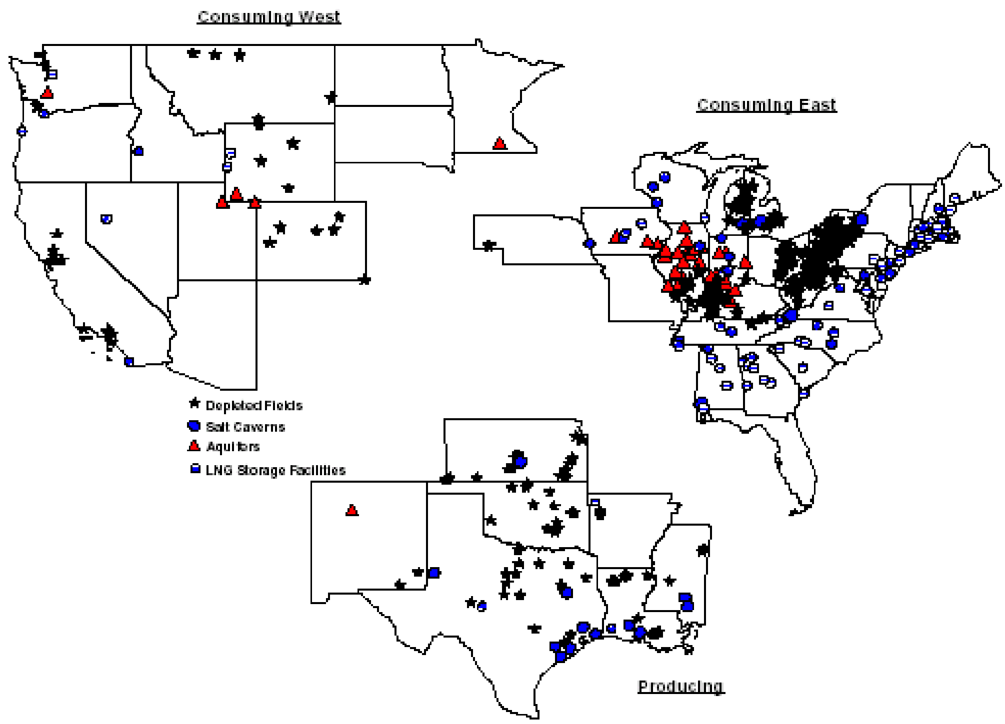
Table 4 Natural Gas Prices in the United States

Dollars per Thousand Cubic Feet

	Nominal Price		Real Price (1999 US$)		Percent Change (Real)
	1985	1999	1985	1999	
Wellhead	2.51	2.07	3.56	2.07	-42
Import	3.17	2.29	4.50	2.29	-49
City gate	3.75	3.11	5.32	3.11	-42
Residential	6.12	6.60	8.69	6.60	-24
Industrial	3.95	3.04	5.61	3.04	-46
Electric Utilities	3.55	2.56	5.04	2.56	-49

Source: Massey [2000a].

Figure 1 Distribution of Storage Sites in the U.S.



Source: Reproduced from Tobin and Thompson [2001].

JAPAN

SUPPLY AND DEMAND AND INDUSTRY STRUCTURE

The Japanese city gas industry has developed mainly in urban areas. Originally, government regulations allowed city gas companies to run their businesses under exclusive supply franchise areas in recognition of the huge initial investment and economies of scale. In turn, they had a supply obligation to their franchise areas after the government's price-setting approval that provided a reasonable price level that protected small consumers from abuse of monopoly power[9].

By taking into account the changing circumstances in the gas industry, the Gas Utility Industry Law, the main legislation governing the gas industries, was revised twice, in 1995 and 1999, for the purpose of lowering the gas price to improve competitiveness. This made gas tariffs to large-volume consumers free of regulation (or approval process) in principle, as long as it involves lowering rates.

As of October 1998, there were 238 gas companies − 68 public corporations and 170 private companies. Four city gas companies, namely Tokyo Gas, Osaka Gas, Toho Gas and Saibu Gas, dominate with a combined 75 percent market share. As Figure 2 shows, most of them are vertically integrated companies to which regional monopoly is permitted.

Feedstock for city gas comprises LNG, indigenous natural gas, coal, LPG and naphtha. In terms of sales volume, 89 percent of total volume relied on natural gas as feedstock. This diversity of feedstock for city gas with different composition and heat content is regarded as an obstacle to an integrated city gas industry. In order to resolve this problem, the Japanese government has been promoting more use of natural gas for city gas feedstock, not only by the big city gas companies but also by small and medium-sized companies. As of 2000, natural gas accounted for 87.3 percent of the total city gas sales volume.

After the introduction of LNG in 1969, natural gas consumption grew considerably until 1998. Natural gas is used mainly for electricity generation (70.3 percent of total usage in 1998), followed by reticulated city gas (28.3 percent) and feedstock for petrochemical industry and industrial fuel (1.3 percent). However, growth in natural gas consumption has recently levelled off. The reason is two-fold: changes in total electricity demand, and changes in the energy mix. From 1980 to 1990, electricity generation output (for the nine major electric utilities) increased at an average rate of 4.4 percent per year, while from 1990 to 1998 it declined overall by 2.5 percent per year due to the economic slowdown in Japan. Additionally, a change in the electricity generation fuel mix from 1990 affected this declining trend. From 1990 to 1998, the share of nuclear power increased from 29 to 40 percent, while the share of natural gas remained at around 29 to 30 percent over the same period. Also, newly constructed coal-fired generation plants have contributed to meeting increasing electricity demand. Nuclear and coal-fired units have been installed for base load generation, while natural gas contributes to intermediate- and peak-load generation units. General natural gas consumption trends since 1969 are illustrated in Figure 3.

With respect to the city gas sector, from 1980 to 1990 natural gas consumption increased by 9.8 percent per year, while from 1990 to 1998 it increased by 6.5 percent per year. City gas feedstock comprises LNG, indigenous natural gas, coal gas, LPG and naphtha. The changing composition of these components since 1973 is shown in Figure 4.

As a major natural gas-consuming economy without enough indigenous production, Japan has huge gas storage facilities across its territory. Due to the vertically integrated regional monopoly tradition, LNG terminals are scattered in coastal areas owned by regional companies (see Figure 5 and Table 7 below). In addition to LNG facilities, there are five underground storage facilities,

[9] Prior to November 1999, gas companies needed to have approval from METI in setting prices to final consumers.

[10] Natural gas refers to LNG and indigenous natural gas.

[11] The remainder utilised LPG, coal and naphtha.

which are depleted gas fields.[12] The capacities of the underground facilities are: total volume is 2,133 million m^3; total working gas 1,168 million m^3; and total cushion gas 965 million m^3.[13]

Figure 2 Japanese Gas Industry Structure

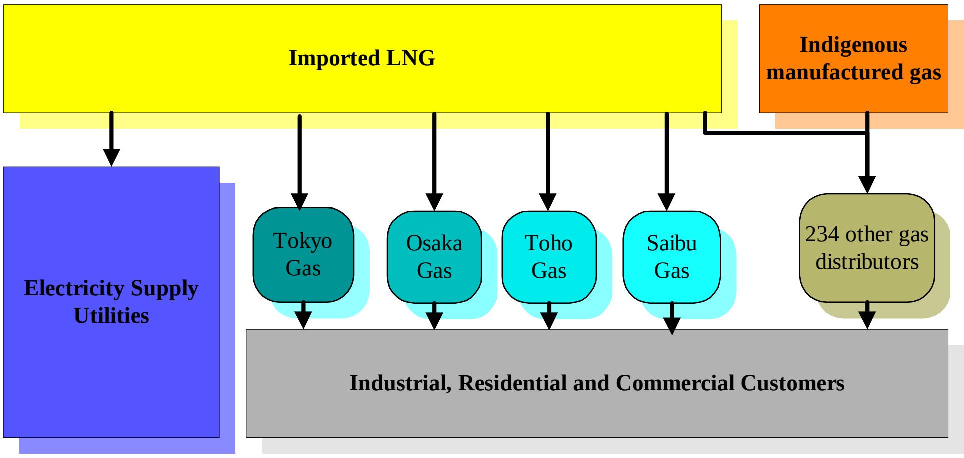
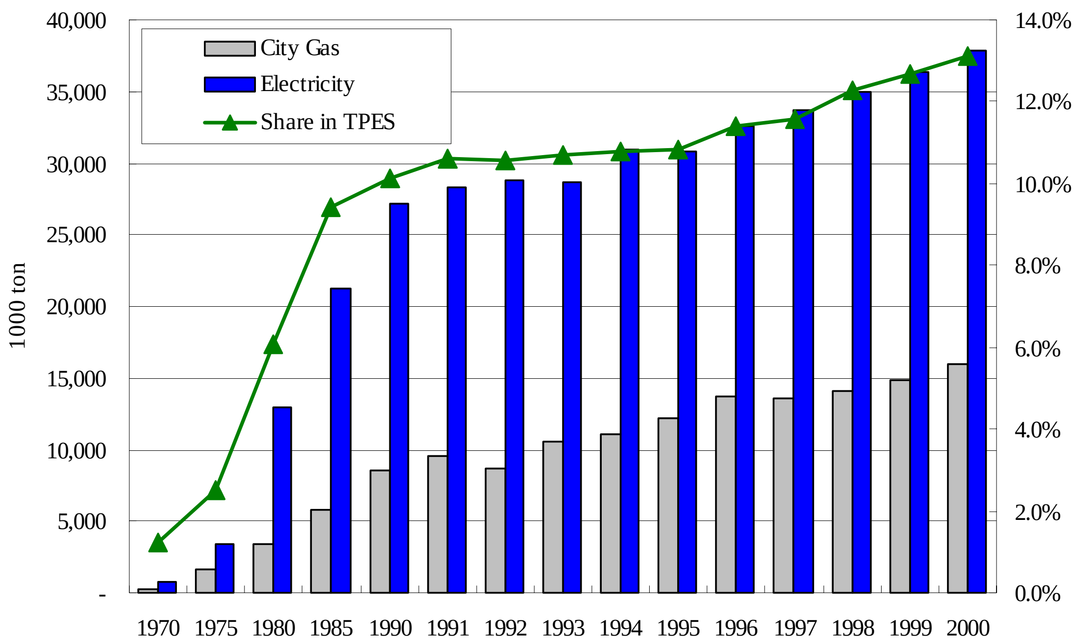


Figure 3 Natural Gas Consumption Trends by Sector in Japan



Note: Time axis not annual prior to 1990.

Source: EDMC, APEC Energy Database.

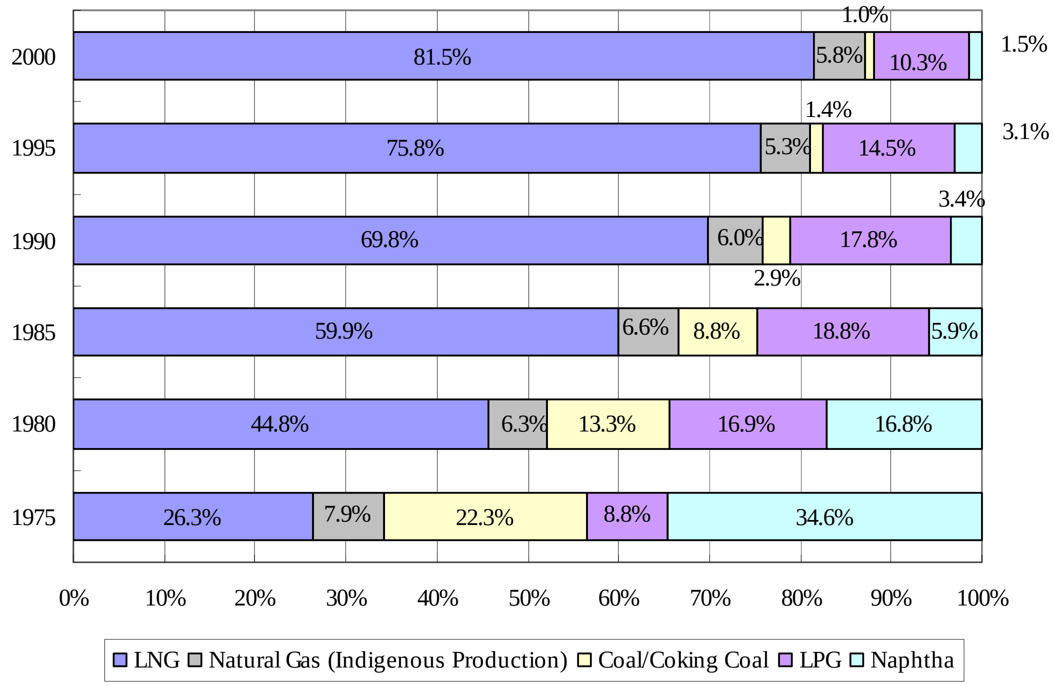
[12] There exist in-ground LNG storage tanks in Japan and some are under construction in Korea. In general, however, the term underground gas storage does not include in-ground LNG tanks.

[13] JNOC [2001] data compiled in 1999.

DEREGULATION OF THE GAS INDUSTRY

Deregulation in the gas market in Japan is being promoted to improve the high-cost structure of the industry through competition, to widen consumer choice, to facilitate more autonomous business management in the industry, and to minimise administrative intervention by the government in the industry. The approach has been gradual rather than radical. One of the underlying rationales for this gradual policy is that, as mentioned above, there are a host of small to large public and private companies in the industry that have varying degrees of capability to adapt to the rapidly changing business environment.

Figure 4 Change in the Composition of Feedstock for City Gas in Japan



Source: Japan Gas Association homepage at http://www.gas.or.jp/default.html

The first phase of deregulation in the gas industry was the amendment of the Gas Utility Industry Law in 1994, which came into effect in 1995. Entry into the market for large-volume consumers with an annual consumption volume over 2 million m^3 was liberalised. Along with (limited) free entry into the bulk supply market, price regulation for supplies to those consumers was repealed, so that the consumer and the supplier could negotiate prices on a contractual basis. The yardstick competition approach was also adopted in the rate-setting procedure for smaller consumers.

As the supply to large-volume consumers was liberalised, an issue was raised concerning transport of gas supplied by new entrants who did not have their own pipelines. The Japanese government issued guidelines for the 'wheeling' of gas by the so-called big three gas utilities (Tokyo Gas, Osaka Gas, and Toho Gas) and limited access to the existing gas pipelines was put in place.

Concerned about the limited competition rendered by the measures implemented by the 1994 Amendment of the Gas Utility Industry Law including gas wheeling, and at the recommendation of some studies and industry groups, the Japanese government and the Diet took one more step towards a more competitive gas market. The law was amended once again and changes implemented from November 1999. In particular, the following changes are noticeable in the amendments for the large-volume market:

- The size of large-volume consumers was reduced from 2 million m^3 per annum to 1 million m^3 per annum;
- The four (the big three plus Saibu Gas) major city gas companies are required to file terms and conditions of gas wheeling to the government (METI) to facilitate entry of gas suppliers with no pipelines of their own and make public their terms and conditions; and
- The approval system of retail rates was abolished and changed to a notification system as long as gas rates would be lowered and gas supply terms and conditions would benefit customers. On the other hand, when city gas companies propose to raise gas rates, they still have to go through an approval process with METI.

The Japanese government is monitoring market developments following the measures taken. Based on observation of the market, it is considering taking third-phase measures from 2002 or 2003. Table 5 summarises some core policies for the phase-in gas industry deregulation initiative.

Table 5 Phases of Gas Industry Deregulation in Japan

Time of Policies Made	Deregulation Policies	Law Being Effective
June 1994	• Entry liberalisation into large-volume market (2 million m^3 pa) • Introduction of yardstick approach to rate-setting	1995
May 1995	• Enlarge large-volume market from 2 million m^3 pa to 1 million m^3 pa • Repeal of rate approval for large-volume customers • Notification system for wholesale rates • Institutionalisation of gas wheeling • Deregulation on safety and business diversification	November 1999
2002~2003 (proposed)	• More steps to take upon monitoring market development	-

ACCESS TO ESSENTIAL FACILITIES: PIPELINES

To prevent excess investment and to have a competitive market, new entrants ought to have non-discriminatory access to essential or bottleneck facilities, which are gas transport pipelines and storage. However, it is argued that the Japanese system for access to essential facilities is not sufficiently objective and transparent, although it is difficult to explain why.

Guidelines on gas wheeling were issued for the big three gas utilities to adopt in making their own rule books in July 1995, and other companies were to follow the terms and conditions in the rule books of the big three. According to the guidelines, the three companies devised and announced their own terms and conditions in May 1996. Nevertheless, the Study Group for City Gas Structural Reform and the companies that were using or considering using the pipelines of other companies complained that there were still entry barriers in the wheeling system and the system was not transparent. In particular, many complaints were made about insufficient information on available capacity of pipelines, the non-transparent standard and procedures for assessing access fees, and other compensation mechanisms, for example, for imbalances.

Therefore, in the Amendment of 1999 of the Gas Utility Industry Law, Saibu Gas was added to the group of big gas companies comprising Tokyo Gas, Osaka Gas and Toho Gas, and the companies were obliged to file their terms and conditions of gas wheeling in their rule books with METI. Also, the imbalance margins were made clear, with the upper and lower bounds set at 10 percent. In addition, the four big companies were obliged to announce basic information such as on gas quality specifications and pipelines for use by other parties.

However, among other points, there were caveats, like the premise that wheeling is provided to the extent that it does not hinder a pipeline owner's gas supply, on what were regarded as major obstacles to the development of a more competitive gas market. Also, being basically a limited access regime, it grants individual pipeline owners the right to determine access fees, which shippers think is a limiting element against more open access to transport capacity, in addition to the problems of still non-transparent procedures and insufficient information. Table 6 shows a summary of the terms and conditions of wheeling by the big three companies.

Table 6 Main Terms and Conditions of Gas Wheeling by the Big Three in Japan

Item	Main Terms and Conditions
General	• Specification of user identification, input and offtake points
Conditions for Wheeling	• Maximum contract period is 3 to 5 years. • One input point and one offtake point are allocated to one contract. • Wheeling is provided to the extent that pipeline capacity allows and wheeling does not hinder pipeline owner's meeting supply obligation. • Gas to be wheeled must be compatible with that of pipeline owner and it may not damage existing customers. • Required gas pressures must be maintained at input and offtake points. • Input-offtake discrepancies must be within specified limits. • Emergency responsiveness is required for safety and supply stability.
Wheeling Fee	• Individual contract between user and owner of pipelines • Fee is calculated on the basis of gas quantity wheeled multiplied by the unit wheeling cost. • Unit wheeling cost is based on contract volume, maximum contracted flow, load factor and facilities cost.
Compensation	• Excess or shortage of input and offtake volume is compensated on an individual contract basis.

Source: Chung [2000].

ACCESS TO ESSENTIAL FACILITIES: LNG TERMINALS[14]

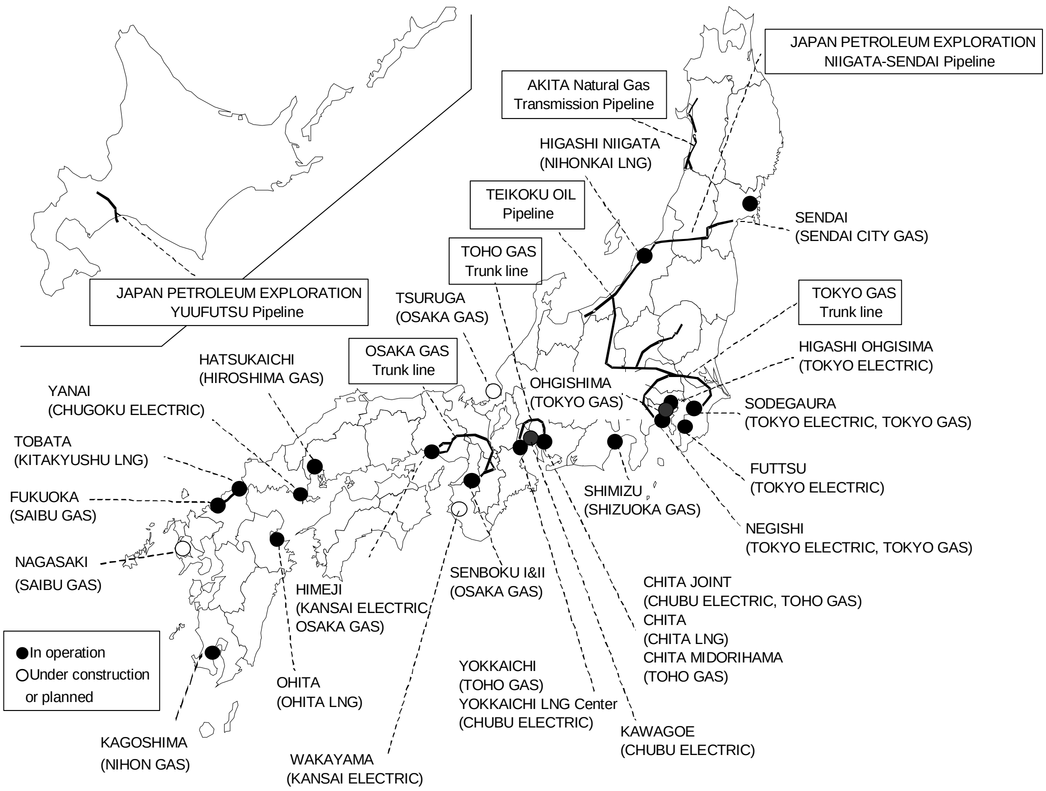
The US government recommended in October 1999 that Japan should establish a regulatory regime for the natural gas industry that would permit non-discriminatory access by new entrants to the existing utility-owned natural gas infrastructure at a reasonable fee, including LNG receiving terminals. Later, in October 2000, the US government recommended more specifically that the Japanese natural gas pipelines and LNG terminals should be unbundled, with a transparent pricing

[14] This section draws on Hasegawa [2002].

mechanism put in place following the model of the US regime of open access in interstate gas transport and gas storage. The recommendations can be summarised as follows:

- Regulation allowing open and non-discriminatory access to LNG terminals and pipelines;
- Unbundling of gas transport and marketing functions to enhance Third-Party Access (TPA);
- Disclosure of information on capacity available for TPA use; and
- Disclosure of information on the asset value and on the way the TPA tariff is determined.

Figure 5 LNG Terminals and Pipelines in Japan



Source: Hasegawa [2002].

In addition to the wheeling or access to transmission pipelines, access to LNG terminals is essential to facilitate a competitive national gas market. This is because LNG terminals are the input points of imported natural gas to the onshore market, and without free access to LNG terminals and storage facilities only a limited degree of competition, if any, is possible. It is known that a study group, called the Gas Market Development Basic Issues Study Group, has been formed within the government (METI) to develop a grand design for the Japanese gas market in 10 years time and a conceptual regulatory framework. Major issues that are under discussion within and outside of the study group include:

Table 7 LNG Terminals in Japan

Terminal	Owner	LNG Imported from	Storage Tank Capacity (kl)*	Start-up Year
Sendai	Sendai City Gas	Malaysia	80,000 (1)	1997
Higashi Niigata	Nihonkai LNG (Tohoku Electric, Development Bank of Niigata Prefecture, JAPEX)	Indonesia, Malaysia, Qatar	720,000 (8)	1984
Futtsu	Tokyo Electric	Australia, Abu Dhabi, Malaysia, Indonesia, Brunei Darussalam	860,000 (8)	1985
Sodegaura	Tokyo Electric, Tokyo Gas	Brunei Darussalam, Malaysia, Australia, Indonesia, Alaska, Qatar	2,660,000 (35)	1973
Higashi Ohgishima	Tokyo Electric	Brunei Darussalam, Malaysia, Australia, Indonesia, Alaska, Abu Dhabi, Qatar	540,000 (9)	1984
Ohgishima	Tokyo Gas	Indonesia, Qatar, Malaysia, Australia	600,000 (3)	1998
Negishi	Tokyo Gas, Tokyo Electric	Brunei Darussalam, Alaska, Malaysia, Australia	1,250,000 (16)	1969
Shimizu	Shimizu LNG (Shizuoka Gas Tonen)	Malaysia	177,200 (2)	1996
Chita Joint	Chubu Electric, Toho Gas	Indonesia, Australia, Qatar, Malaysia	300,000 (4)	1977
Chita LNG	Chita LNG (Chubu Electric, Toho Gas)	Indonesia, Australia, Qatar, Malaysia	640,000 (7)	1983
Yokkaichi	Toho Gas	Indonesia	160,000 (2)	1991
Yokkaichi LNG Centre	Chubu Electric	Indonesia, Australia, Qatar	320,000 (4)	1987
Kawagoe	Chubu Electric	Indonesia, Australia, Qatar	480,000 (4)	1997
Senboku I	Osaka Gas	Brunei Darussalam	180,000 (4)	1972
Senboku II	Osaka Gas	Indonesia, Australia, Malaysia, Qatar	1,585,000 (18)	1972
Himeji	Osaka Gas	Indonesia, Australia, Brunei, Oman, Qatar	560,000 (7)	1984
Himeji	Kansai Electric	Indonesia, Australia, Malaysia, Qatar	520,000 (7)	1979
Hatsukaichi	Hiroshima Gas	Indonesia	85,000 (1)	1996
Yanai	Chugoku Electric	Australia, Qatar	480,000 (6)	1990
Ohita	Ohita LNG (Kyushu Electric, Kyushu Oil, Ohita Gas)	Australia, Indonesia	460,000 (5)	1990
Tobata	Kita Kyushu LNG (Kyushu Electric, Nippon Steel)	Indonesia	480,000 (8)	1977
Fukuoka	Saibu Gas	Malaysia	70,000 (2)	1993
Kagoshima	Nihon Gas	Malaysia	36,000 (1)	1996
Chita Midorihama	Toho Gas	Indonesia, Australia, Qatar, Malaysia	200,000 (1)	2001
Nagasaki	Saibu Gas	-	35,000 (1)	2003
Tsuruga	Osaka Gas	-	1,800,000 (10)	2020
Joetsu	Joetsu Joint Power (Tohoku Electric, Chubu Electric)	-	720,000 (6)	2007
Wakayama	Kansai Electric	-	720,000 (6)	2011
Sakai	Sakai LNG (Kansai Electric, Iwatani Corp., Cosmo Oil)	-	420,000 (3)	2005
Mizushima	Chugoku Electric, Nisseki Mitsubishi	-	140,000~160,000	2006

Note: Number of tank units is in parentheses.

Source: Institute of Energy Economics, Japan.

- Price gaps between indigenous gas and imported gas and price gaps between utilities;
- Scope of the liberalised market;
- Policies needed to enhance the construction of pipelines, for example, different regulations in different energy industries, preferential treatment of industries constructing pipelines for the public, and allowed rate of return;
- TPA to LNG receiving terminals and mandatory stockpiling of LNG; and
- Other policies for supply reliability, consumer protection, and safety in system operation.

KOREA

INDUSTRY STRUCTURE

The natural gas industry in Korea has grown very rapidly. Since its first imports in 1986, natural gas consumption has increased almost eight-fold, with an average annual growth rate of 18.3 percent (see Table 8). This high consumption growth was mainly due to the increase in city gas consumption but also with a significant contribution from power generation use.

In the early stage of natural gas supply, the power generation sector accounted for most of the market demand. But with the addition of transmission and distribution pipelines, city gas demands expanded very rapidly. The average annual demand growth of city gas use from 1987 to 1999 was 45.2 percent, while that of power generation, coming off a higher base, was 8.6 percent.

Major players in the Korean natural gas industry include: the Korea Gas Corporation (KOGAS), city gas companies, large-volume consumers, and the central government and local governments as regulators. Their identities and main functions are explained briefly below.

KOGAS is the only importer and wholesaler of natural gas at the moment. It owns and operates LNG receiving terminals and nationwide trunk lines. As a monopoly supplier, it supplies natural gas to power generators – currently the newly created five generating subsidiaries of Korea Electric Power Corporation (KEPCO) and Hanwha Energy and cogenerating companies, and large-volume consumers with consumption volume over 100,000 m^3/month. It also supplies wholesale gas to retail city gas companies.

There are 24 city gas companies among 32 firms using LNG as feedstock. They buy wholesale natural gas from KOGAS, and enjoy local monopoly status in their service territory.

Large-volume consumers were allowed to import natural gas for their own use from 2001, but not to import gas for resale. If necessary for transport purposes, they can access the KOGAS pipeline network for a fee. The structure and level of the fee will be decided before the first access by the Pohang Steel Company (POSCO) to the KOGAS grid. POSCO is scheduled to access the KOGAS grid in 2002. Figure 6 shows the current structure of the natural gas industry in Korea.

The Gas Industry Division of the Ministry of Commerce, Industry and Energy (MOCIE) approves supply terms and conditions, rates of wholesale gas and direct supply contracts of KOGAS with large-volume consumers. The Ministry of Finance and Economy (MOFE) coordinates the levels of gas rates with MOCIE for concerns with inflation. Local governments approve supply terms and conditions and rates of retail gas for the city gas companies within their jurisdiction.

Table 8 LNG Consumption in Korea

thousand tons (% share)

Year	Power Generation	City Gas	Own Use	Total
1986	45 (84.9)	0 (0)	8 (15.1)	53
1987	1,537 (94.8)	75 (4.6)	9 (0.6)	1621
1988	1,905 (91.0)	184 (8.8)	5 (0.2)	2094
1989	1,670 (82.4)	349 (17.2)	8 (0.4)	2027
1990	1,741 (74.8)	575 (24.7)	12 (0.5)	2328
1991	1,800 (66.8)	879 (32.6)	15 (0.6)	2694
1992	2,225 (63.1)	1256 (35.6)	43 (1.2)	3524
1993	2,518 (57.2)	1,848 (42.0)	37 (0.8)	4403
1994	3,329 (56.8)	2,451 (41.8)	80 (1.4)	5860
1995	3,606 (50.7)	3,413 (47.9)	100 (1.4)	7118
1996	4,622 (49.1)	4,619 (49.1)	175 (1.8)	9416
1997	5,377 (47.3)	5,770 (50.7)	232 (2.0)	11,379
1998	4,189 (39.3)	6,233 (58.5)	222 (2.1)	10,646
1999	4,769 (36.8)	7,886 (60.8)	306 (2.4)	12,961
2000	4,491 (31.3)	9,528 (66.4)	340 (2.4)	14,359
Average Growth Rate since 1987 (%)	8.6	45.2	32.2	18.3

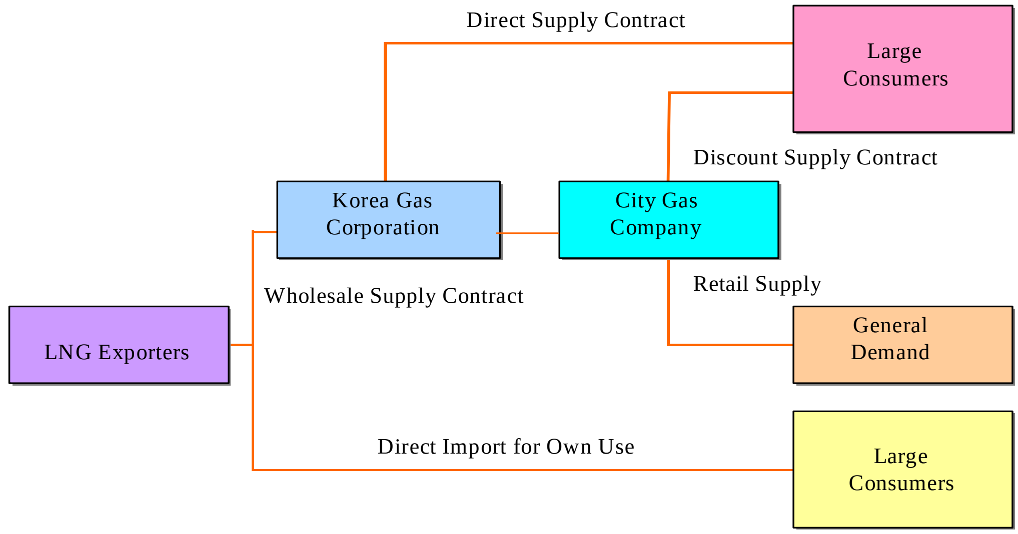
Source: Korea Energy Economics Institute, Monthly Energy Statistics.

There are three laws that govern the city gas industry where natural gas is used as feedstock: the Law of City Gas Industry; the Law of Petroleum Industry; and the Law of Safety Management of High-Pressure Gases. Also, another special law (that is, one that applies above other laws for applicable circumstances) provides rules specifically for enhancing efficiency of the management and the privatising of four major public enterprises, one of which is KOGAS. The Law of City Gas Industry provides the basic framework of the city gas industry, including but not limited to: license-related matters for the importation and supply of gas, construction of gas supply facilities, terms and conditions of gas supply, safety management and land acquisition.

The Law of Petroleum Industry governs matters related to importing natural gas. This law treats natural gas as a kind of petroleum and, accordingly, an importer of natural gas is regarded as an importer of petroleum. There was some confusion in the interpretation of two laws, the Law of Petroleum Industry and the Law of City Gas Industry. The problem was that, when POSCO obtained the permission, what did the permission permit POSCO to do? Could POSCO undertake the business of gas supply, that is, could it import natural gas for resale? Or could it import natural gas only for use within the company? The final interpretation of the laws was that POSCO could import natural gas only for its own use, and could not sell the gas it imports.

The Law of Safety Management of High-Pressure Gases governs the safety issues that occur in the process of handling and using high-pressure gases and constructing facilities to supply those gases. Issues related to natural gas supply and consumption in this law concern the authority of the Korea Gas Safety Corporation. The corporation was established by this law and authorised to issue licences for handling high-pressure gases, and to oversee the safety of gas facilities and appliances and safety activities of gas suppliers, construction contractors and gas consumers.

Figure 6 Current Korean Natural Gas Industry Structure



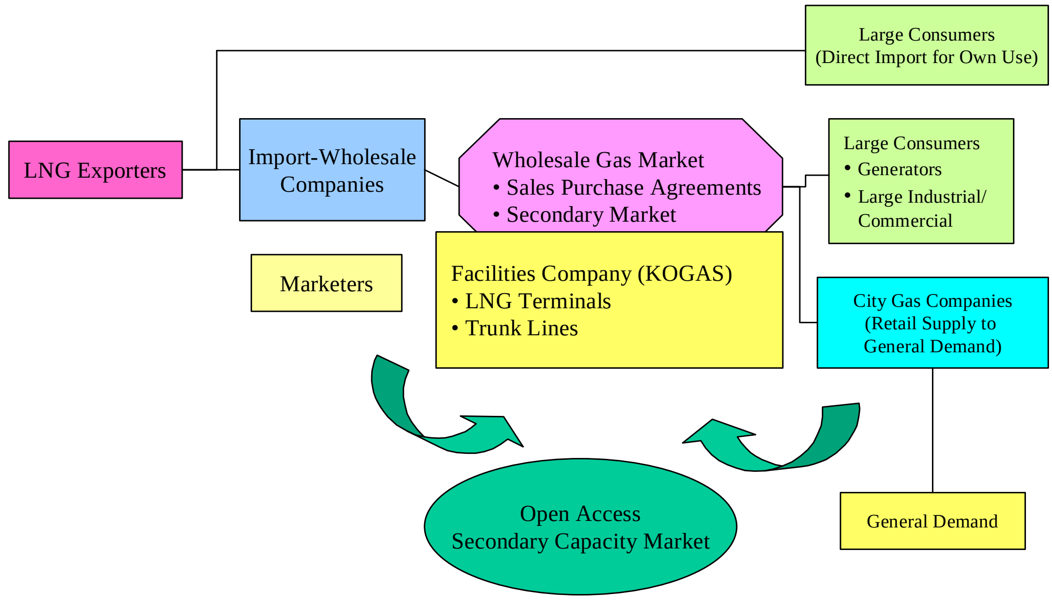
A special law, the Law of Improvement of Managerial Efficiency and Privatisation of Public Enterprises, was enacted in August 1997 and has been effective since October 1, 1997. This law is concerned with the managerial efficiency of the four major public enterprises that have attributes of private companies in their operation, early privatisation of the companies, and ways of preventing concentration of market power by equity-holders of the companies. The law takes priority over other laws in ruling on matters associated with the governance structure of the companies.

Two draft amendments of laws and a new draft law ruling the natural gas industry were approved by the cabinet in December 2001: the Draft Amendment of the Law of Korea Gas Corporation; the Draft Amendment of the Law of City Gas Industry; and the Draft Law of the Gas Commission. These laws are being enacted in accordance with the Base Plan released in November 1999 and the Action Plan for the Natural Gas Industry Restructuring released in August 2001. Once the draft laws are passed by the National Assembly, they will underpin the restructured natural gas industry.

It is envisaged that, in the first phase of the restructured Korean natural gas industry, there will be three import-wholesale companies that will take over the existing SPAs from KOGAS and make new SPAs as required. One of them will remain a subsidiary of KOGAS. Its main function will be to support imbalances between supply and demand that KOGAS and the government believed would be likely to occur in the market where private companies supply wholesale gas. KOGAS will own and operate terminals and trunk lines to which an open access regime will be applied. Retail supply will remain a regional monopoly with supply and distribution services bundled for the time being until effective competition is achieved in the wholesale market.

A gas exchange will be established to facilitate trade in gas by market participants. The whole industry will be overseen by the Gas Commission, which will be established within the government. However, the jurisdiction of the Commission will be limited to the oversight of market operations, dispute resolution and deliberation of policy issues for the government. No authority will be granted for it to make policies or to issue licences for gas supply business. Authority for licence issuance and price-setting will lie with the central government, instead of the currently segregated jurisdictions between central and local governments. Figure 7 shows a schematic of the restructured natural gas industry of Korea.

Figure 7 Korean Natural Gas Industry Structure at First-Phase Restructuring



WHOLESALE PRICE STRUCTURE

The wholesale price charged by KOGAS consists of two components − the feedstock cost and supply costs. There are seven items that constitute the feedstock cost: (i) the import price, (ii) an import handling charge, (iii) an import tariff, (iv) a special excise tax, (v) losses, (vi) an import surcharge, (vii) a safety management surcharge. Among the items, the import surcharge and the safety management surcharge are applied only to city gas customers (see Table 9). Since the LNG import price is indexed to the oil price, to reflect fluctuations in the import price and in the exchange rate the feedstock cost is adjusted on a monthly basis for power generation customers. In contrast, to avoid frequent price changes, the feedstock cost adjustment is considered on a quarterly basis for city gas customers and implemented only if the rise or fall exceeds three percent.

The wholesale supply cost is calculated and adjusted annually, and consists of the receiving terminal costs and transport costs. For power generation customers, three seasonally varying rates are applied: winter, summer, and other seasons. For city gas customers, supply costs differ by end-user type. There are five classes of end-uses for city gas customers: residential/heating (includes cooking, heating, business office heating), cooling, commercial, industrial, building co-generation and district heating. For each end-use type, a uniform rate is applied throughout the year, except for the building co-generation and district heating use, which has three different seasonal rates.

Table 9 and Table 10 show figures of the components that constitute feedstock costs and supply costs, respectively, as of January 1, 2000. In order to diversify energy sources and to rapidly increase the penetration of natural gas, feedstock and supply costs were kept low, especially in the early years of LNG imports. Although direct government subsidies for natural gas were absent, natural gas has received preferential tax treatment. The import tariff on LNG is only one percent, whereas that on crude oil and LPG is five percent. Other charges levied on alternative fuels, such as the import surcharge, the special excise tax and the safety management surcharge, were not introduced to LNG until after 1994. Moreover, the revenue from the import surcharge was set aside as the 'petroleum business fund' and loaned out for the construction of the natural gas pipeline network at a low interest rate. This also contributed, along with other measures, towards keeping the supply cost of natural gas low compared with other fuels.

Table 9 Wholesale Feedstock Cost Components in Korea

Won/m³

Components	Electricity	City Gas	Remarks
Import Price	287.87		Contract Price
Import Handling Charge	2.83		Importing Incidental Expenses including inspections fees and losses
Import Tariff	2.59		0.9% of CIF
Special Excise Tax	32.31		Flat amount of 40 won/kg
Import Surcharge	-	5.58	Flat amount of 6,908 won/ton
Safety Mgt Surcharge	-	3.90	Flat amount of 3.90 won/m^3
Total	325.60	335.08	

Source: KEEI, internal data.

Table 10 Wholesale Supply Costs in Korea

Won/m³

End-User Class		Winter	Summer	Other	Remarks
Power generation		45.54	26.06	35.80	
City Gas	Residential/Heating		107.21		
	Cooling		-134.03		May –Sep
	Commercial		45.69		
	Industrial		33.17		
	Building Co-generation & District Heating	70.19	0.00	33.17	

Note: City gas supply costs are effective December 1, 2001. Average supply cost of city gas is 78.08 won/m³, which has decreased from 84.88 won/m³.

WHOLESALE SUPPLY COST ALLOCATION METHOD

At present, the assessment of supply costs is based on the recovery of average accounting costs, and is carried out by the following steps. First, the total costs to be recovered are classified by the five functional cost pools of unloading, storage, regasification/injection, pipelines, and valve stations. The second step is to allocate each functional cost between the power generation and city gas sectors based on their average consumption patterns. The cost allocation factors for each function are as follows:

(i) Unloading costs – annual consumption volume

(ii) Storage – necessary storage volume to support each consumption sector

(iii) Regasification/injection – maximum monthly injected volume

(iv) Pipelines – separate assets by power generation sector exclusive and city gas sector exclusive (common costs are divided by reflecting load factors: monthly average consumption / load factor)

(v) Valve stations – the same as for pipelines

The cost allocation method used by KOGAS has improved a great deal by better attributing the costs incurred by each sector. Accordingly, the cross-subsidy problem has been greatly alleviated thanks to the elimination of overt cost-shifting practices and corrective measures taken to reflect the attributable costs.

However, cross-subsidies may still be present, if the term is used loosely as applied to any case when prices do not reflect the supply cost difference. In this sense, it is the appropriateness of cost allocation that becomes the relevant criteria for discerning cross-subsidisation, rather than the economic definition. It is true that objective cost allocation criteria on which all can agree are absent and they can be arbitrary, but even with the current allocation method accepted as reasonable, it falls short of reflecting attributable costs to an extent that is satisfactory. Specifically, it fails to capture hidden cost factors such as avoided storage costs and differences in service contents.

Due to the demand patterns of power generation customers, city gas customers are saving a great deal in terms of the storage cost. Without power generation demand, more storage tanks would have to be built to accommodate city gas demand patterns. The cost of storage tanks that are avoided should be properly reflected in the pricing. Also, during the peak season there have been cases where power generation customers were asked to stop using natural gas temporarily in order to relieve pipeline capacity/gas shortage problems. In effect, the supply service to power generation is interruptible, while to city gas customers it is a firm service. But this difference in service content is also not appropriately reflected in the pricing.

RETAIL PRICE STRUCTURE

At the city gas company level, the retail price consists of feedstock costs and supply costs. The former is the wholesale price (city gate price) charged by KOGAS to city gas companies. The import price of LNG is adjusted quarterly according to changes in the foreign exchange rate and the LNG price. A 10 percent value-added tax (VAT) is added to the supply costs of retail companies. Rate-making is based on cost-plus methodology with a 10 percent after-tax rate of return on equity capital. Each local government approves the city gas price of the city gas company/companies within its jurisdiction. If more than one city gas company operates within a jurisdiction, end-use prices, in principle, are determined as an average of the supply costs of those companies. While in principle rate revisions are undertaken every year, the local government has some flexibility in revising the rate within a three-year period considering such economic circumstances as the stability of gas rates and the general price level.

Rates are differentiated by end-use type and determined by local governments. There are nine types of end-use in the case of the metropolitan Seoul area, as follows, although the categorisation may be different across localities.

- Residential Cooking/Residential Heating
- Commercial I/Commercial II

- Building Heating/Building Cooling
- Industrial
- Building Cogeneration
- District Heating

There are no seasonal differential rates. But since the load factor of city gas consumers is much lower than for power generation customers, the turn-down ratio is much higher in the city gas sector. It is therefore difficult to maintain supply and demand balances, especially in the winter season, and KOGAS and city gas companies signed a load adjustment contract which provides some incentives to manage loads on the part of the city gas companies. The agreement, reached in February 1996, stipulates that if the offtakes by a city gas company are above or below the allowance of ±10 percent of contracted amount, it will pay a penalty calculated as the divergence from the allowance times two percent of the KOGAS supply price. The penalty period has changed in frequency: there was no penalty during 1996; the penalty was assessed on a quarterly basis in 1997; and from 1998 the penalty has been assessed on a monthly basis. However, in times of extraordinary weather conditions, some allowance can be negotiated. Currently, weather conditions are regarded as extraordinary depending on whether it is warmer or colder by more than the standard deviation of temperature during the time period of the year in question.

CHINESE TAIPEI

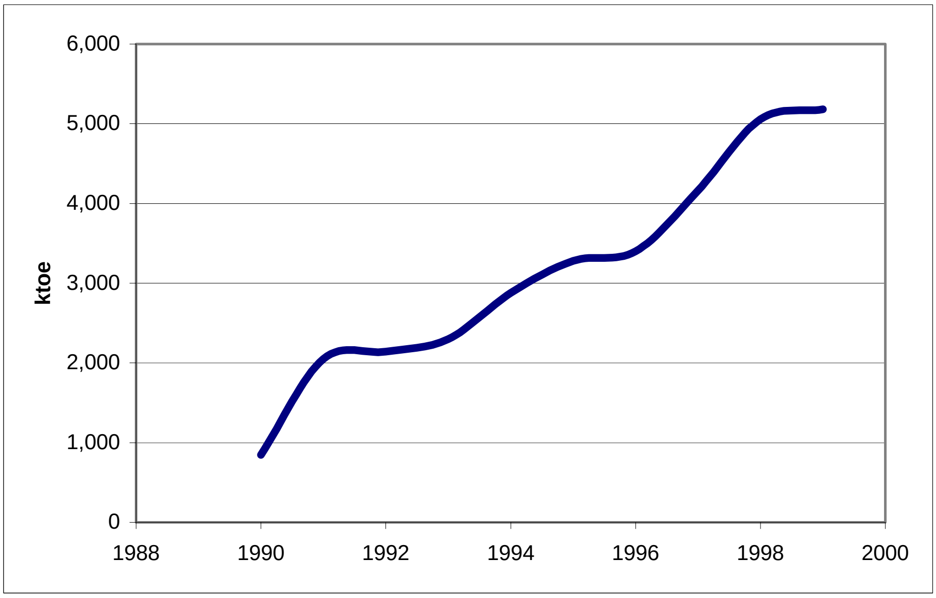
SUPPLY AND DEMAND OF NATURAL GAS

In view of the limited reserves of natural gas in Chinese Taipei, as well as the clean and convenient features of LNG and the advantage of supply on a long-term basis, this economy imports most of its needed natural gas in LNG form from Malaysia and Indonesia. The quantity of LNG imports has increased dramatically in the past 10 years.

In 1999, 61 percent of LNG was used for energy transformation including power generation and cogeneration. Chinese Petroleum Corporation (CPC) is responsible for the supply of natural gas in Chinese Taipei, but a private natural gas supplier will join this market in a few years. In contrast to CPC, Taiwan Power Company (Taipower) still controls the electricity market and is the largest buyer of CPC's LNG. Taipower's peak demand period for electricity coincides with the CPC's peak demand period for LNG, because Taipower uses natural gas for power generation for peak loads. Taipower's use of LNG is concentrated in the summer (June-September), and peak periods (10 a.m.-noon, and 2 p.m.-5 p.m.). This indicates that peak demand for LNG occurs in summer not in winter. Moreover, the daily load curve of LNG may change moderately, because the price of gas is high compared with other fuels and gas-fired power plants are operated only for peak-shaving.

The consumption of LNG is simple to project because Taipower is the largest user of LNG and its pattern can be projected in advance. Hence, CPC can save costs of LNG storage and does not need to be concerned about shortage of LNG supply. However, LNG may have been expensive for Taipower since the pattern of LNG consumption in energy transformation is not continuous and a large proportion of fixed investment costs should be amortised. If gas-fired plants are operated to meet intermediate and base loads, the cost of LNG may be decreased to an attractive level. However, LNG is not likely to be competitive with nuclear or coal as a power generation fuel.

Figure 8 LNG Import in Chinese Taipei



Source: Taiwan Energy Statistics 1999.

Another reason for the high cost of LNG lies in the fact that the pipelines from the First Receiving Terminal are for the exclusive use of Taipower's power plants, cogenerators and IPPs. The rationale is that 61 percent of the LNG is used for energy transformation, and no large final users can share these pipelines. If more users could share them, LNG prices might be lower.

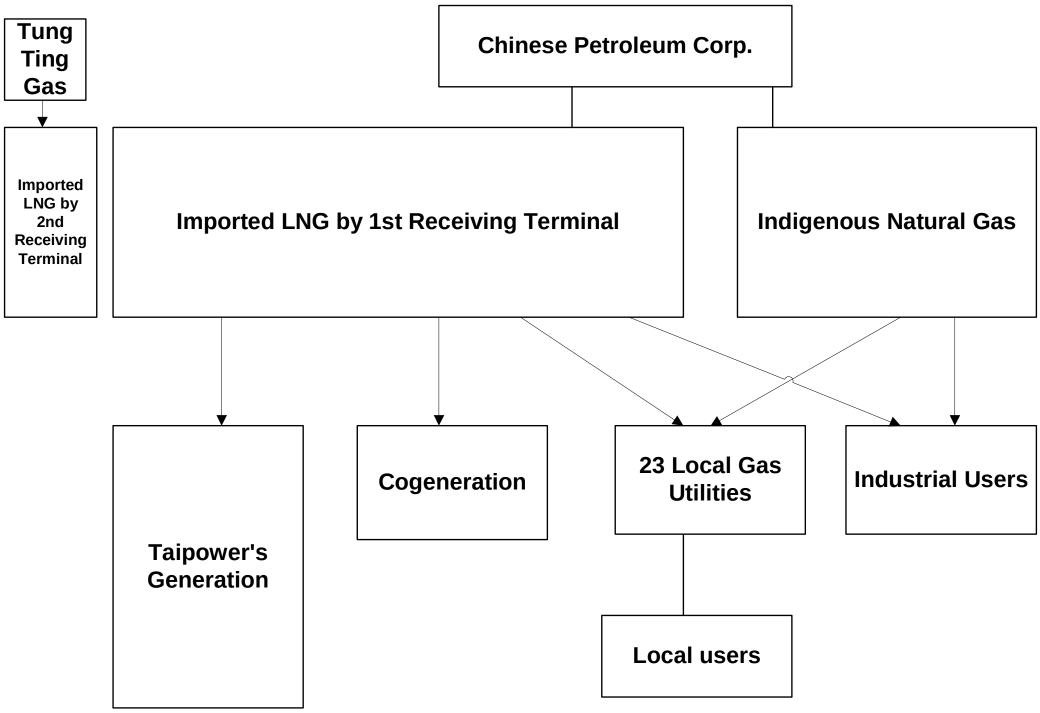
Carbon dioxide emissions control is an important factor influencing the consumption of natural gas in Chinese Taipei. Although Chinese Taipei has no obligations under current agreements to control carbon dioxide emissions, it attempts to protect the environment and achieve sustainable development. Most carbon dioxide emissions are from Taipower's power generation. In order to control carbon dioxide emissions, Chinese Taipei promotes the use of natural gas to replace coal.

Besides Taipower's existing gas-fired power plants, many IPP projects using gas are under development. One IPP plant of 900 MW capacity was completed and began commercial operations in 1999. The national projection of annual growth rate of LNG consumption from 2000 to 2020 is 6.7 percent. This means natural gas will play an important role in the energy scene of Chinese Taipei in the future. The rationale for this projection is that natural gas prices will fall as consumption of it rises to an economic scale, and a lower price will promote its use.

In 1999, 19 percent of LNG was used for final consumption including the energy, industrial, and residential and commercial sectors. The residential use of gas has been stable, consuming more gas in winter for water heating.

CPC, a state-owned enterprise under the Ministry of Economic Affairs, is entrusted with exploration, development, refining, transport, and marketing and sales of natural gas. CPC has imported LNG from Southeast Asia since 1980. Imported LNG amounted to 4.43 million tons in 2000, of which 2.62 million tons came from Indonesia, while the remainder was from Malaysia. Imported LNG is expected to reach 4.96 million tons in 2001.

Figure 9 Gas Industry Structure in Chinese Taipei



Note: 1) The second LNG receiving terminal is under construction as of the writing up of this report.

2) No lines are indicated for gas supply from the second LNG terminal owned by Tung Ting Gas, since several options are under consideration. They include a yearly supply of 1.8 million tons to Ta-Tan power plant, power generation fuel for Kuantang Industrial Park with a 3,000 MW generation capacity, and some residential use in northern Chinese Taipei.

CPC's monopoly in the LNG supply business will come to an end as Taipower tenders for natural gas for its Ta-Tan power station, which is being built in Northern Chinese Taipei. It has been reported that the relationship between CPC and Taipower, the largest gas consumer in the economy, is strained by Taipower's perception that it had been paying too high a price for CPC's gas.

In anticipation of upcoming IPP projects, CPC made a short-term deal for additional cargoes with PERTAMINA in 1998 and 1999. However, as the projects were slow to progress and, as a consequence, CPC had surplus gas supplies, the company negotiated two deals to divert a total of nine LNG cargoes to KOGAS and Chubu Electric Company during the 2000-01 winter season. Although the total volume was not large, it is an example of swap deal in Northeast Asia.

GAS PRICING MECHANISM

Chinese Taipei has implemented several policy measures to lower the price of natural gas. In October 2000, the government repealed the excise tax on natural gas to promote its consumption, reduce carbon dioxide emissions and stimulate the economy. Based on this new policy, CPC decreased its gas price by about seven percent immediately. Similarly, gas utilities decreased their prices for local users in response to the decreased city gate price. In addition, the import duty on natural gas, now five percent, will be gradually phased out.

CPC applies different prices of natural gas for industrial users, local gas utilities, cogenerators, and Taipower. Based on the price for industrial users, CPC develops its prices mechanism in practice. There are 23 local gas utilities that buy and resell 18 percent of CPC's natural gas. These utilities are regarded as industrial users. Thus, the price for these gas utilities is the same as the price for the industrial users. The price for Taipower is about 83 percent of that for the industrial users. The reason is that Taipower purchases about 50 percent of CPC's LNG, which contributes to around a 15 percent reduction in the cost of CPC's gas supply. In return for this, CPC gives a 17 percent discount on the LNG price to Taipower. In addition, there is a five percent difference for seasonal and peak prices. The price for cogenerators is about 91.5 percent of the price for industrial users, since Chinese Taipei encourages cogeneration as it is helpful for energy saving. The gas utilities' prices for local users are regulated and must be approved before implementation.

Table 11 CPC's Gas Pricing Mechanism

User	Gas Price	Remarks
Industrial Users	standard price (A)	Based on cost-of-service method
Local Gas Utilities	100% x (A)	There are 23 local gas utilities that buy and resell 18% of CPC's natural gas. These utilities can be regarded as industrial users.
Cogenerator	91.5% x (A)	Chinese Taipei encourages cogeneration because it is helpful for energy saving.
Taipower and IPPs	83% x (A) and 5% difference for peak and off-peak periods	Taipower buys about 50% LNG from CPC, which decreases CPC's cost of gas supply by 15%. In return, CPC gives a 17% discount to Taipower and IPPs.

Source: CPC.

FIRST RECEIVING TERMINAL OF CPC IN SOURTHERN CHINESE TAIPEI

CPC was assigned to construct and operate the first LNG receiving terminal in Chinese Taipei. Located at Yungan in Kaohsiung, construction of the terminal began in 1984 and it was completed and came into operation in 1990 with an annual handling capacity of 1.5 million tons.

In view of the constantly expanding demand for this fuel since the opening of the terminal, CPC launched an expansion project when the terminal was put onstream. With enlarged storage facilities and extended gas trunk lines, the handling capacity was boosted to 4.5 million tons of LNG at the end of 1996. In anticipation of the future growth of gas consumption, CPC took the initiative to further enlarge the capacity of related facilities. On completion of the project in a few years, CPC will be able to handle 7.87 million tons of LNG annually.

There are six LNG storage tanks in the First Receiving Terminal. Three of them have 100,000 kl of capacity each, and the other three each have 130,000 kl. However, the latter three are under repair, resulting in 300,000 kl of available capacity as of the time of writing this report. CPC hopes to complete these three LNG storage tanks as soon as possible to increase its capacity of LNG storage. In 2001, it is reported, the total volume of LNG handled through the storage facility amounted to 10,200,000 kl, with the turnover ratio of storage tanks being 34. This figure is substantially higher than 14.8 for Korea in 1999, which is also regarded as too high to accommodate a secure supply of LNG.

CPC is asked to be responsible for a stable supply of LNG. In order to prevent shortages of LNG, CPC should maintain reasonable LNG storage capacity. As for the inventory of LNG, CPC hopes to keep a seven-day safety reserve for both peak and off-peak periods. The CPC's LNG storage policy is based on past experience that bad weather may prevent LNG carriers from entering CPC's LNG receiving terminal for not more than seven days. A storage volume of seven days consumption of LNG is considered sufficient to guarantee CPC's ability to supply enough LNG to customers while ignoring the weather factor temporarily. The difficulty of siting LNG storage facilities and cost considerations also influenced the setting of the safety reserve margin.

In addition to imported LNG, CPC has indigenous gas supplies, for example in southern Chinese Taipei, to dispatch during peak time. Although the quantity of indigenous gas supply is only a small proportion of total gas supply, it can complement imported LNG. While there are no specific regulations on CPC for LNG storage, there are rules on local gas utilities and LPG suppliers. Based on Article 3 of the Implementation Regulations of Energy Management Law, the local gas utilities must construct gas storage facilities. It is stipulated, in Article 19 of the Regulations Concerning the Management Permission of Import, Export, Production and Marketing of Petroleum and Its Products, that the safety stock of LPG should amount to no less than 25 days supply on the basis of average domestic sales and consumption in the past 12 months. In addition, the safety stock must be no less than 50,000 kl for imported LPG and LNG, and 10,000 kl for imported LPG. To further enhance the stability of natural gas supply, the government of Chinese Taipei is now aggressively promoting the construction of a second LNG receiving terminal in the north.

SECOND RECEVING TERMINAL OF TUNG TING GAS IN NORTHERN CHINESE TAIPEI

Chinese Taipei decided that a second LNG receiving terminal should be built and operated by a private entity in line with the deregulation and privatisation of the energy sector. Major participation by state-owned companies is not allowed. Instead, Tung Ting Gas was granted permission in May 2001, to build the second LNG receiving terminal, located in the Kuantang Industrial Park and Industrial Port.

Tung Ting Gas is a joint venture of China Development Industrial Bank, Uni-President Group and Evergreen Group on the side of Chinese Taipei, as well as Mitsubishi Heavy Industries, Itochu Corp, Kansai Electric and Osaka Gas of Japan. Tung Ting started as a subsidiary of the financially troubled Tuntex Group but now operates as an autonomous entity.

The second terminal is to supply natural gas to the Ta-Tan power plant, which is being built in Taoyuan County by state-owned Taipower. The total installed capacity of the Ta-Tan power plant will be 4,000 MW and the first stage of its construction is to be completed by 2002. Taipower had planned to sign a 25-year LNG supply contract for the Ta-Tan plant with an annual supply of 1.8 million tons of LNG by 2007 on completion of the power plant. The LNG supply was to originate from Indonesia's Tangguh Project. However, Taipower decided to postpone the Ta-Tan power project in late October 2001, since the load forecast for the next 10 years showed that it would grow at 3.6 percent instead of the previously forecast 5.5 percent. The 25-year contract between Taipower and the fuel supplier may be adjusted due to the postponement of the Ta-Tan power project.

CHAPTER 4

THEORY OF PEAK-LOAD PRICING AND OPTIMAL PLANT MIX

PEAK-LOAD PRICING AND OPTIMAL PLANT MIX

In this section, we review the theory of peak-load pricing. To avoid complex theoretical exposition and to link the theory to our discussion about gas storage, only some of the more important results and their practical implications will be presented.[15] First a definition:

> 'Peak-load pricing refers to the pricing of economically non-storable commodities whose demand varies periodically. If price were uniform over time, quantity demanded would rise and fall periodically. To meet demand at the peak would then require the installation of capacity which is under-utilised over the remainder of the cycle. Since the capacity is not costless, the resulting idleness during the off peak is the basis for the peak-load problem and the motivation for pricing to mitigate this inefficiency.' (Crew et al. [1995], p. 216)

Although the term 'pricing' seems to suggest that the price is determined by a regulator, the theory is applied not only to the regulated sector but also to a competitive market in its capacity to match demand and supply and consequently prices, as we will see in the discussion of consumer self-rationing. For ease of discussion, we will assume the goods are supplied by a regulated sector. Since the main purpose of this section is to present the basic theoretical results and their application in the field with diverse technology, we will omit the one-technology model.

Some of the important assumptions and notations employed in this section are as follows:

Consumers are of various types $\theta \in \Theta$, where $f(\theta)$ is the number of consumers of type θ.

The preferences of consumers are assumed to be of the separable form, $U(x, m, \theta) = V(x, \theta) + m$, $\theta \in \Theta$, i.e., there are no income effects.

$N = \{1, \ldots, n\}$: a set of natural numbers 1 to n

$x = (x_1, \ldots, x_n)$: the vector of goods supplied by the regulated sector

$P = (P_1, \ldots, P_n)$: the vector of prices of the goods supplied by the regulated sector

m: Hicksian aggregate

X_i: total demand of good i

$X = (X_1, \ldots, X_n)$: the vector of total demand

$C(X)$: cost function of the monopolist supplying X

With the above assumptions and notations, the Ramsey problem can be written as

[15] Crew and Kleindorfer [1986] and Crew et al. [1995] provide a good survey of the literature on peak-load pricing, and this section draws on their work following the notations used there.

$$Max\, W(P)_{P\geq 0} = \int_{\theta}\left[V(x(P,\theta),\theta) - \sum_N P_i x_i(P,\theta)\right] f(\theta)d\theta + \Pi(P) \qquad (1)$$

subject to:

$$\Pi(P) = \sum_N P_i X_i(P) - C(X) \geq \Pi_0, \qquad (2)$$

where $\Pi(P)$ is profit and Π_0 is some desired profit level.

The well-known Ramsey result is:

$$\sum_{j\in N} \frac{(P_j - C_j)}{P_j}\eta_{ij} = -\kappa, \quad i \in N,$$

where η_{ij} is the price j elasticity of demand for product i and $\kappa = \lambda/(1+\lambda)$ is the so-called Ramsey number which is positive except at the welfare optimum where the required profit level Π_0 is such that the profit constraint is not binding so that $\kappa = 0$. λ is the Lagrange multiplier for the profit constraint.

When there are only two products in the regulated sector, we obtain

$$\frac{P_i - C_i}{P_i} = -\frac{\kappa}{\Delta}\left(\eta_{jj} - \frac{R_j}{R_i}\eta_{ji}\right), \quad i = 1, 2,\ j \neq i, \qquad (3)$$

where $\Delta = \eta_{11}\eta_{22} - \eta_{12}\eta_{21}$ and R_i is revenue from product i. If own-price effects dominate cross-effects, Δ is positive. We can see that equation (3) reduces to the standard inverse elasticity rule when $\eta_{ij} = 0$ for all $j \neq i$ and the following results hold.

(i) If products 1 and 2 are substitutes ($\eta_{ij} > 0$ for $i \neq j$), then $P_i \geq C_i$ with $P_i > C_i$, i = 1, 2, except at the unconstrained welfare optimum.

(ii) If products 1 and 2 are complements ($\eta_{ij} < 0$ for all i, j), the $P_i < C_i$ is possible at optimum for one of the two products.

In the peak-load pricing problem, products are differentiated only by the time of consumption and are therefore typically substitutes, so that the above results imply that price will always exceed marginal cost in all periods except when the profit constraint is not binding, namely, at the welfare optimum. Complements usually arise in this context only when one of the goods is an 'access good' such as connection to the network. This good could be priced below marginal cost, depending on relative elasticity and revenue conditions.

PEAK-LOAD PRICING WITH DIVERSE TECHNOLOGY

This theory considers pricing and capacity decisions where more than one type of technology is available to meet demand. As mentioned above, this case is typical for public utilities. In the case of a firm peak, for example, it may be economical to employ an additional technology type to help meet peak-period demand. Such a peaking technology or plant would typically have lower construction costs and higher operating costs relative to existing technologies or plants, providing cost advantages in meeting peak demand for a short duration.

Suppose there are T periods in the basic cycle of operation with $t = 1, \ldots, T$. Technology is specified through H types of capacity denoted $h = 1, \ldots, H$, having constant marginal operating cost b_h and marginal capacity cost β_h. The cost function $C(X)$ is specified as

$$C(X) = Min_{q_{ht}, Q_h} \sum_{h=1}^{H} \sum_{t=1}^{T} b_h q_{ht} + \sum_{h=1}^{H} \beta_h Q_h$$

subject to:

$$\sum_{h=1}^{H} q_{ht} = X_t, \text{ for all } t, \tag{4}$$

$$Q_h - q_{ht} \geq 0, \text{ for all } h, t; \tag{5}$$

$$q_{ht} \geq 0, Q_h \geq 0, \text{ for all } h, t, \tag{6}$$

where X_t is demand in period t, Q_h is capacity of type h and q_{ht} is output from capacity (or technology) h in period t. Constraint (4) specifies that demand be met in each period, while (5) requires output from technology h in each period not exceed capacity of technology h.

OPTIMAL PLANT MIX

Assume that the H available technologies have been numbered so that the following cost conditions hold:

$$\beta_1 > \ldots > \beta_H > 0; 0 < b_1 < \ldots < b_H.$$

The reason that we can assume this is that if such a numbering were not possible, then some plant type h would have a lower β and a lower b than some other technology k, so that k would be dominated by h. Three propositions are derived from the above formulation.

(a) For all technologies h and k for which $h < k$, the following must hold if both technologies are to be used in the optimal solution.

$$\frac{\beta_h - \beta_k}{T} < b_k - b_h < \beta_h - \beta_k. \tag{7}$$

If the left-hand (respectively, right-hand) of inequality (7) is violated, only technology k (respectively, technology h) need be used in any optimal solution.

(b) Using the numbering of technologies above, the efficient technological frontier is downward-sloping and convex in (b, β) space.

(c) Assuming the numbering of technologies above and that the costs satisfy (7), capacity is installed and operated in order of increasing operating cost. In particular, technology 1 is used in every period, i.e., $q_{1t} > 0$ for all t.

Proposition (a) says that if k is lower in the merit order than h, that is, $b_h < b_k$, and if both technologies are to be used, technology h (respectively k) must be cheaper to use in supplying a unit of a demand over T periods (respectively for one period) than technology k (respectively h). Proposition (b) says that from any two technologies h and k a third technology can be constructed as a convex combination by operating h and k a fraction α and $(1-\alpha)$ of the time, and that the combination technology dominates any technology that is not on the convex frontier. Proposition (c) says that once capacity is installed, it should be operated in merit order.

The optimal pricing problem can be formulated as following:

$$Max_{P\geq 0} W(P) = \int_{\theta}\left[V(x(P,\theta),\theta - \sum_{t=1}^{T} p_t x_t(P,\theta)\right] f(\theta)d\theta + \Pi(P)$$

$$= \int_{\theta} V(x(P,\theta),\theta) f(\theta)d\theta - \left(\sum_{h=1}^{H}\sum_{t=1}^{T} b_h q_{ht} + \sum_{h=1}^{H} \beta_h Q_h\right)$$

subject to the profit constraint (2), and those of capacity and output (4), (5), and (6).

For the case of two-technology $H = T = 2$, assume a firm-peak case ($X_1 < X_2$ at optimum) and both technologies are used at the optimum. Then optimal prices are obtained as:

$$P_1 = 2b_1 + \beta_1 - (b_2+\beta_2),\ \ P_2 = b_2 + \beta_2 \tag{8}$$

$$Q_1 = q_{11} = q_{12} = X_1 > 0,\ \ q_{21} = 0,\ \ Q_2 = q_{22} = X_2 - X_1 > 0. \tag{9}$$

(9) shows that, given $b_1 < b_2$ and $\beta_1 > \beta_2$, $q_{11} = X_1$ so that off-peak demand is met by technology 1, which is more expensive to construct but cheaper to operate than technology 2. Technology 1 continues to supply $q_{12} = X_1$ units in the peak period with the additional peak requirements $X_2 - X_1$ being met by technology 2. In sum, the cheaper operating-cost technology is used in both periods and the more expensive one used only to meek peak demand.

The prices can be shown to have the following relationship:

$$b_1 < P_1 < b_2 < b_2+\beta_2 = P_2 < b_1+\beta_1. \tag{10}$$

Although it is not shown here, in the case of one-technology we have $P_1 = b_1$ and $P_2 = b_1 = \beta_1$. This and the result (10) imply that the introduction of a more diverse technology leads to higher off-peak prices and lower peak-period prices.

PEAK-LOAD PRICING UNDER UNCERTAINTY

The above discussion is about the deterministic model. The peak-load pricing problem under uncertainty introduces randomness, with the result that states of excess demand may occur which require rationing of available supply. Efficient pricing rules require joint consideration of willingness-to-pay for services rendered, when supply is sufficient to meet demand, and for services not rendered plus any rationing costs incurred in excess demand states. Capacity choices are similarly driven by both the marginal cost of capacity and the marginal benefits of avoided excess demand states and resulting rationing. Various extensions to this basic framework allow the consideration of priority pricing rules, interruptible tariffs, time and space differentiated pricing, and other means of reducing welfare losses in excess demand states.

Assume that a utility has a single technology and there exists only a single pricing period of unit length. Let the annualised capacity cost of the technology be β per unit capacity and the operating cost be b per unit. Let $x(P, \theta, \omega)$ be individual demand and $X(P, \omega)$ aggregate demand at each state of the world $\omega \in \Omega$ by

$$x(P,\theta,\omega) \in \arg\max_{x\geq 0}\left[V(x,\theta,\omega) + M(\theta) - Px\right]$$

and

$$X(P,\omega) = \int_{\theta\in\Theta} x(P,\theta,\omega) f(\theta)d\theta,$$

where X is downward sloping in P for every ω and has all requisite continuity and measurability properties. Let the total installed capacity be denoted by Y. Assuming that the installed capacity consists of a continuum of supply units and the operation of each of these units is assumed to be stochastically independent of each other unit and of demand, the available capacity at ω, $A(Y, \omega)$ is given by

$$A(Y,\omega) = \int_0^Y a(u,\omega)du,$$

where $a(u, \omega) \in (0,1]$ and where, for every infinitesimal supply unit $u \in [0, Y]$, $E\{\tilde{a}(u)\} = \xi$ which is called the availability factor. Random variables are denoted by a tilde.

Output supplied is stochastic and is specified by

$$Q(P,Y,\omega) = Min[X(P,\omega), A(Y,\omega)].$$

In the presence of demand and supply uncertainty, it is important to recognise the possibility of outage, meaning excess demand, in certain states. Kleindorfer and Fernando [1993] separate the costs associated with outage into three elements: (i) rationing cost, which is the cost incurred by the utility in allocating scarce supply, (ii) disruption cost, and (iii) surplus loss. The latter two elements of costs are incurred by the consumer. Surplus loss represents the foregone willingness-to-pay in excess of price. Disruption cost is the cost incurred by the consumer in excess of surplus loss due to the disruption associated with the supply outage.[16]

Assume that both rationing and disruption costs are linear functions of excess demand. Denote disruption and rationing cost per unit of excess demand per unit time by δ and r respectively, which are assumed to be homogeneous across the consumer population. Define the probability of excess demand not occurring as $\Omega_0(P, Y) = \{\omega | X(P, \omega) \leq A(Y, \omega)\}$ and that of excess demand occurring as $\Omega_1(P, Y) = \{\omega | X(P, \omega) > A(Y, \omega)\}$. And denote reliability by $Pr\{\Omega_0(P,Y)\} = (1-\rho)$. Then, we obtain the following optimal 'unreliability' ρ^* and optimal price P^*.

$$\rho^* = \frac{\frac{\beta}{\xi} - \Lambda}{\frac{\beta}{\xi} - \Lambda + (\delta + r)\frac{E\{X'(P)\}}{E\{X'(P) | \Omega_0(P,Y)\}}}$$

and

$$P^* = b + \frac{\beta}{\xi} - \Lambda - (\delta + r)\left[1 - \frac{E\{X'(P)\}}{E\{X'(P) | \Omega_0(P,Y)\}}\right],$$

where Λ is defined as

$$\Lambda(P,Y) = E\{P(A(Y)) | \Omega_1(P,Y)\}\rho - P\rho.$$

We see that the optimal price decreases as the technology is more available across states, and as the disruption cost and rationing cost increase with other things being equal. It has been assumed in the discussion that rationing is applied according to willingness-to-pay. Under this assumption, Λ is the expected value of the excess of willingness-to-pay over price for energy that is not

[16] More discussion on outage cost follows below.

provided to the marginal consumer. One thing to note is that both price and capacity should be jointly decided under uncertainty, because keeping sufficient capacity to meet all demands in every possible state of the world would be prohibitively expensive.

The case of diverse technologies and multiple periods under uncertainty is similar to the deterministic case, except for accounting for expected rationing losses and uncertain availability of capacity. In short, the price in each period should be set equal to expected short-run marginal cost, including expected marginal disruption and rationing costs. Capacity should be set so that the per-unit cost of the last technology used (divided by its availability factor) equals the expected marginal disruption and rationing costs (typically incurred in peak periods) avoided by an additional unit of capacity.

RATIONING RULES AND OUTAGE COSTS

A basic point in the above discussion is that in the presence of uncertainty about demand or supply, and price setting ex ante (prior to an event happening), the utility needs to use both price rationing and quantity rationing to efficiently allocate available capacity. Prices alone are not capable of limiting demand to available supply in all states of the world, even if they are set to vary across time in a pre-determined fashion, and it would be prohibitively expensive to carry surplus capacity in the system to eliminate all possible outage events. This raises several important issues about how and on what basis capacity shortfalls may be allocated across the consumer population.

It is known that as we move from rationing in order of increasing willingness-to-pay through random rationing to rationing in order of decreasing willingness-to-pay, welfare optimal prices increase and capacity and reliability increase. This is in line with the simple intuition that, as rationing becomes more inefficient, meaning it is moving in the opposite direction to that mentioned above, optimal price and capacity are increased to reduce the probability of excess demand states and the necessity of (inefficient) rationing. However, it is necessary to have at least some knowledge of the outage costs incurred by each consumer in order to implement an efficient rationing scheme, which would ration in increasing order of these outage costs.

In the context of electricity supply, Munasinghe and Sanghvi [1988] discuss the importance of accurate outage cost assessments in setting optimal prices and reliability levels.[17] Outage costs represent the economic consequences of service curtailments to the customer when the demand for electricity temporarily exceeds the available supply capability. Outage costs are normally estimated by a reduction in customer willingness-to-pay to avoid interruptions in the short run (assuming that the user does not have enough time to change their energy-using capital stock).

Shortage costs reflect any changes in the customer value of service (willingness-to-pay) following a change in service quality relative to the reliability level they presently receive. They are also referred to as long-run outage costs and include the costs that the consumer incurs to change energy-using capital stock and other processes in response to a change in supply quality. For example, if service reliability were lowered significantly or reliability requirements were to increase, then some consumers would find it cost effective to take one or more mitigating actions (long-run mitigation measures) to cope with future service curtailments by, for example, installing fuel-switching facilities or relocating to service areas with higher reliability.

Adaptive response costs represent the capital and operating costs that are incurred by the consumer after the adaptive responsive measures have been taken. Shortage costs reflect both adaptive response costs and expected outage costs after the adaptation has taken place. Therefore, (long-run) shortage costs are lower than (short-run) outage costs. Otherwise, the consumer would not find mitigation measures worthwhile.

[17] The discussion about the outage cost concepts draws on their work.

Consider the decision faced by a customer who must select between two options, a firm service and a service that offers inferior reliability. If an option offers inferior service quality, such as more frequent curtailments, then the willingness-to-pay is reduced as well, shifting the demand curve downward. This reduction reflects two main components. The first is a shortage cost, which consists of the cost of any adaptation by the consumer, for example, as measured by incremental changes in user capital stock, as well as the change in expected outage costs in the future conditional on such adaptation. The other is a risk premium component that reflects, among other things, user tolerance for risk as it pertains to the service's reliability. As reliability deteriorates, it can trigger higher anxiety, stress and other adverse customer response, although they may differ among different customers. In addition, even if a customer installs emergency backup capability, it may prove inconvenient to operate and maintain.

The shortage costs plus any risk premium together define the value of service reliability. For example, if service reliability is increased, we would expect the value of service to increase by an amount equal to the corresponding change in shortage costs plus the risk premium.

Munasinghe and Sanghvi [1988] summarise the costs incurred by outage of electricity (see Table 12). Although they only dealt with electricity, the costs shown in the table can be applied to natural gas, particularly to the extent that natural gas competes with and substitutes for electricity in providing energy services.

To the extent that electricity and natural gas are not substitutes due to their generic differences as energy sources and depending on the value and costs of energy services provided, the kind and size of some cost items will appear differently. For residential consumers, for instance, a gas outage would tend to cause less spoilage and property damage than an electricity outage. The potential for social costs stemming from looting and vandalism may be minimal in the case of a natural gas outage, mainly because electricity can be supplied using other fuels than natural gas.

The costs incurred by electricity generators through a gas outage which are not presented in the table − natural gas is a primary energy in the transformation sector − can be easily explained with the table. In this case, the direct costs of a power outage can be interpreted as the indirect costs of an outage of gas that is used for power generation. The indirect costs of an outage of electricity will be the more indirect costs of a gas outage. Direct costs of a gas outage to power generators will include: opportunity costs of idle resources; shutdown and restart costs; and spoilage and damage. Additional fuel costs incurred by fuel-switching and possible revenue losses resulting from lessened load responsiveness in a competitive electricity market can be added to the direct costs. All these costs will be affected by the fuel-switching capability of the generator and the prices of electricity and electricity generation fuels.

Despite its importance and attempts at accurate outage cost measurement, it has proved difficult, especially when it is based on survey method. Survey-based estimates are known to be plagued, among other things, by the status quo bias. This bias arises from the empirical observation that survey participants attach a much higher cost to a marginal reduction in service reliability (meaning willingness-to-accept a decrease in reliability) than they are willing to pay for a marginal improvement in service reliability. A related problem is that consumers in industrialised economies usually have very limited, if any, experience of outages, which seems to upwardly bias their assessment of outage costs. Also, it is known that if consumers are asked to report their outage costs in the knowledge that this information will be used to ration supplies, they will have an incentive to give false signals, which would most likely inflate their true costs.

Table 12 Direct and Indirect Outage Costs of Electricity

Primary User	Direct Costs	Indirect Costs	Remarks
Residential	• Inconvenience, lost leisure, stress, etc. • Out-of-pocket costs: Spoilage and property damage • Health and safety effects	• Costs on other households and firms	Indirect costs are a minimal, if not negligible, fraction of total costs of a curtailment.
Industrial, Commercial, and Agricultural	• Opportunity costs of idle resources: labor, land, capital, profits • Shutdown and restart costs • Spoilage and damage • Health and safety effects	Cost components include: • Cost to other firms that are supplied by impacted firm (multiplier effect) • Costs on consumers if impacted firm supplies final good • Cost (benefits) to some producers • Health and safety related externalities	Indirect effects are likely to be minimal for most capacity related interruptions, but can be a significant component of total costs for longer duration energy shortfalls.
Infrastructure and Public Service	• Opportunity costs of idle resources • Spoilage and damage	• Costs to public users of impacted services and institutions • Health and safety effects • Potential for social costs stemming from looting, vandalism	Indirect costs constitute a major portion of total costs of a curtailment.

Source: Munasinghe and Sanghvi [1988].

SELF-REVELATION OF OUTAGE COST

In this section, three branches of the theory will be briefly overviewed in an attempt to explain the schemes in which consumers can themselves select their level of service reliability. They are spot or real-time pricing, self-rationing, and priority service.

REAL-TIME PRICING

The basic idea behind this concept is that prices can be set after at least a partial resolution of the uncertainty about the outcome of demand and supply. Thus, prices respond dynamically to conditions in the market place such that the market clears all the time, thereby eliminating the need for any quantity rationing. This is the first-best outcome in a world without transaction costs and where consumers are neutral to the risk of constantly varying prices and are able to respond optimally to the price signals.

The real-time pricing framework has usually encompassed price variation in both space and time. Thus, apart from the benefits associated with time variation, these prices are also capable of reflecting the costs associated with transport losses and constraints across the service network. However, while this framework may provide a market-based decentralised mechanism for network pricing if competition is present, it does not address questions of reliability and how this could be ensured in a network with a diverse set of self-interested users.

Apart from the problems associated with transaction costs, risk aversion, and consumer responsiveness, a significant drawback of the literature on real-time pricing is that it (almost by definition) has no provision for quantity rationing, assuming instead that the market would clear through price adjustment under all contingencies. However, as is evident from the quasi-spot market for the purchase of electric power in the UK and the US, this could lead to sharp peaks in the electricity price when demand is incapable of responding fully to price signals in the market period. Furthermore, in practice, spot prices are actually set as much as 24 hours ahead, and differences between 24-hour ahead expectations and actual outcomes can be quite considerable. These drawbacks may, however, be less critical in some public utility sectors than in others. Additionally, the benefits of having at least a subset of consumers (such as large industrial and commercial users) on a scheme of spot pricing are very clear and have been well demonstrated in practice. However, the scope for extension to a broader set of users appears to be limited.

SELF-RATIONING

The literature on self-rationing is also a response to the problems associated with quantity rationing in the traditional peak-load pricing framework. One way proposed for self-rationing is that each consumer subscribes to a level of capacity which is specified prior to the revelation of the state of the world. The consumer pays a capacity charge for the amount of capacity ('fuse size') subscribed to, as well as a charge for actual consumption. Consumer selection of a fuse size is intended to reflect willingness-to-pay: consumers with a high willingness-to-pay (and consequently a high willingness-to-pay foregone in the event of an outage) would select a high fuse size and vice versa. The utility would select the fuse and usage prices as well as system capacity so as to maximise social welfare.

However, one of the weaknesses of this scheme is the inefficiency arising from individual users reaching their fuse limits at times when the system as a whole has excess capacity. This arises from the fact that the utility has no capability to override the fuses in such situations. Some theoretical attempts have been made to overcome this weakness by, for example, reducing the possibility of perverse curtailments or by activating curtailments only at times of system peak. But these schemes assume that capacity installed by the utility is equal to the sum of the fuse sizes, which is sub-optimal when individual demands are less than perfectly correlated. Lee [1993] suggests a rule of capacity selection which provides for the possibility of purchasing capacity from third-party sources when excess demand occurs. He allows for different coincidence patterns of consumer demands with system peak demands in an n-period stochastic demand model. The optimal prices in this framework will normally involve unit charges above variable cost and demand reservation charges below unit capacity costs.

PRIORITY SERVICE

The third branch of the literature that relies on consumer self-selection to avoid problems associated with capacity rationing is the literature on priority or interruptible service. While diverse models have been developed in this setting, the basic idea is that the market is cleared through price signals that reflect the quality (reliability) of the service as well as quantity. It is known that both the utility and all consumers are made better off as the number of priority classes increases, even though this number may be limited.

DISCUSSION

While spot pricing ignores the need for any capacity rationing and hence the issue of outage costs, the rest of the literature in this area also makes quite simple assumptions about surplus and disruption costs, namely that these costs can be collapsed into a single parameter which equates the value of consuming the unit (whether or not excess demand exists) to the lost value of not consuming the unit in the event of curtailment. Disregard for the different elements of outage costs can lead to problems, especially since the costs of disruption are known to be considerably higher than the loss in consumer surplus. Hence, ignoring this term would lead to under-investment in capacity. Although it is an empirical question and will be discussed more in later sections, this kind of unawareness of consumer disruption costs was presented in the debate about independent gas supply in Korea as a main reason for the shortage of gas and gas supply facilities for power generation in the winter season.

Although the theory was inspired by real world problems, it is been said that successful and widespread application of its results have been more recent (Baumol and Faulhaber [1988]). And, as such, many compromises have to be made in real world applications. Among others, transaction costs, notably metering costs, have traditionally been a major concern in the application of peak-load pricing. While metering costs have been reduced significantly, they still are significant for small customers. Thus, some kind of compromise in terms of the number of pricing periods is likely to be inevitable.

It seems the most interesting issue for our purpose is the implications of storage. As an early attempt, Nguyen [1976] showed that, with storage facilities, fewer plants will in general be used, peak price will be lower than otherwise, and considerable welfare benefits can be obtained. Thanawalla concludes that in a gas industry with access to storage and with an established financial market for trading gas, firms with rational expectations will use gas strategically over time.[18] A simulation result of long-run dynamics, the study shows that access to storage by risk-neutral shippers reduces the volatility in prices and in consumption induced by sudden changes in firm demands and network congestion. The results of these are intuitive and suggest more competitive and less expensive storage market for higher welfare.

However, as mentioned earlier, peak-load pricing refers to the pricing of economically non-storable commodities for which demand varies periodically. As such, the literature on peak-load pricing has not paid much attention to the storage issue. The more capacity that is available at the lower price, the more efficient becomes the commodity market in question. Although it cannot cover the whole range of issues, a more interesting approach may be that we assume balancing service is demanded by the system operator and analyse issues around gas storage. This will involve a different look at the same issue and a new preference structure for the system operator, including their risk aversion. Traditional consumers and system users will be treated as suppliers of balancing service. There will be a variety of balancing services. As the business structure is more commercialised, there will remain lesser roles for the system operator and the legitimacy of the new approach will decrease. However, to the extent that the gas supply industry remains a network industry and the role of the system operator is to maintain the system security, this approach may be applied.

[18] Thanawalla, R. K., 'The Role of Storage in UK Interruptible Gas Supplies', mimeo. Heriot-Watt University, undated.

CHAPTER 5

DEVELOPMENT OF COMMERCIAL STRUCTURE AROUND GAS STORAGE

INTRODUCTION

While the US and the UK are the most advanced economies in terms of market-based gas trading arrangements, the actual industry practices are quite different. The US system is regarded as a standard form of the bilateral model, whereas the UK model is one of poolco. The bilateral model is based on decentralised bilateral transactions, where market participants conclude all deals in bilateral negotiations and write contracts that address all issues relevant to the deals. Traders and marketers emerge to meet the desire of market participants to save transactions cost. As natural gas is traded as a commodity, spot markets for both physical and financial gas are developed.

In the poolco model, transactions are coordinated by a single entity, a pool operator, which is assigned a market clearing responsibility both for gas and transport (including storage) by the regulator. This model is based on the notion that the bilateral trading model does not always lead to a social optimum, particularly due to technical characteristics of the gas network. Market participants inform the pool operator of all details of their transactions and the pool operator aggregates all information and clears the market. Gas flows do not always coincide with the contractual paths as the pool operator can often find a more efficient way to direct the flows through the gas system.

Although the trading models have been adopted depending on the characteristics of the natural gas pipeline network and industry practices of the economy concerned, both trading models are supposed to result in optimal market outcomes if properly implemented. Also, the poolco model may be more efficient for a gas market than for another market, at least at certain stage of development of the gas system, and it would be natural to introduce as many bilateral attributes as possible in the poolco model. The reason is that all kinds of transactions in a capitalist economy are essentially bilateral, and it is perfectly sensible for intermediaries to facilitate bilateral transactions. Of course, any transaction between the intermediary and the parties are of a bilateral nature, too. Full-scale retail competition in the UK could provide an example of incorporating more bilateral transactions in the market. A simple typological comparison is given in Table 13.

As the natural gas industry is deregulated and liberalised, natural gas prices have tended to fluctuate more than the past. This has raised the value of gas storage capacity substantially and, particularly, the unbundling of gas storage from pipeline business has enabled the storage owner/operator to enjoy the economic rent attached to storage facilities. Profit-maximising storage owners/operators look for markets where prices are high because of a lack of competition, frequent congestion of the pipeline system, or high seasonality of gas consumption. A storage facility can increase competition in a local market because it becomes another player in the market, giving other market participants another choice in selecting a supplier or buyer. And the success of one storage facility can attract more operators, further increasing competition, as evidenced by the development of independent storage operators in the US and the UK.

Table 13 Bilateral Model vs. Poolco Model

	Bilateral	Poolco
Market Size	• Relatively large gas market • Rely on decentralised actions of market forces to develop a liquid and competitive spot market.	• Smaller gas market • Speed up development of a spot market.
Structure of Pipeline System	• Trunk line structure • Network externalities are small.	• Dense network structure • Large network externalities
Information Requirements	• Relatively simple	• Large information requirements on pool operator
Application	• Almost all countries • Simpler to implement • Retail competition based on direct access	• Only the UK • Adoption considered in Korea

Source: Juris [undated].

Deregulating storage operations can help relieve pipeline congestion. In a local gas market, high seasonal variation in natural gas prices may reflect pipeline capacity constraints in peak periods. A storage operator can use the available pipeline capacity in off-peak periods, when natural gas prices are low, to inject natural gas into storage, and then sell this gas in the local market for higher prices during peak periods. The storage operator reaps the benefits of high peak prices, but it also pushes peak prices towards competitive levels because the availability of natural gas from storage relieves congestion, at least partially. And its high profits will attract additional storage facilities to the market, which will further lower prices.

Storage operators face two major problems in deregulated gas markets. The first is concerned with volatile gas prices, which introduce much uncertainty into decisions about the size and location of a storage facility, although price fluctuation itself offers profit opportunities at the same time. Since most storage profits come from location- and time-based price arbitrage, being able to predict future prices is crucial. Storage operators benefit greatly from price discovery in the financial gas market, which provides efficient signals about future gas prices. If the financial gas market is not developed, storage operators can reduce price uncertainty by signing a long-term supply or purchase contract.

The second problem is linked to regulation of storage. Despite its increasing commercialisation, storage still serves as a tool to balance load in the pipeline network. If a storage facility serves both functions, it becomes subject to regulation because of its link to the regulated pipeline transport segment. But distinguishing the costs associated with load balancing from the costs associated with regular commercial operation is difficult, so determining the charges for load balancing is a complicated and imprecise exercise.

The remedy is to create a balance market, where a pipeline company trades system imbalances with other participants in the gas market. It should be noted that in a more developed gas market, pipeline companies need and should not trade imbalances. Instead, shippers or those who own and trade natural gas should do it. A balance market is a market where pipeline system imbalances are traded through an auction. The balance market can be operational in a market where there are more than two shippers or system users who are responsible for balancing their input and offtake of gas. So far, its practical implementation has been limited to the UK.

An efficient balance market produces information with wide utilisation in the deregulated gas industry. The prices generated by the balance market can be used for pricing the load balancing services provided by storage owner/operators to pipeline companies. The price of a system imbalance reflects the costs that the imbalances of individual shippers impose on the pipeline system, so the pipeline operator knows exactly how much it must recover from undisciplined shippers. Finally, the cost of restoring system balance signals to the pipeline operator when to use the balance market and when to curtail gas flows.

In the poolco model, the pool operator can divide the natural gas market into several local markets (nodes) if there is insufficient pipeline capacity to move natural gas between locations. It would then determine prices for each node using the same procedure as in the bilateral model. Transport is sold as a service that takes natural gas in or releases it from the pipeline system at a particular location. The prices of transport services are based on the market value of capacity and throughput. Prices vary in time and across locations, reflecting differences in the market value of capacity. A pipeline company determines the value of capacity as the difference between nodal prices of natural gas, because this difference reflects the congestion rent earned by a congested pipeline. Competitive local gas spot markets generate efficient signals about the size of the congestion rent, ensuring that shippers pay efficient prices for transport services and can make optimal transactions in natural gas and transport markets.

As storage service, which has traditionally been provided by pipeline companies, is separated from transport service, part of the congestion rent is vested in the storage business. However, as mentioned above, it is difficult to determine the amount exactly, and it can only be done by the market. This is why institutional arrangements must be designed so that the market can produce the best outcome. We will overview below some important aspects of the changing gas industries in selected economies to look at the roles of gas storage in different gas markets.

USES OF GAS STORAGE BY CUSTOMER SEGMENT IN THE UNITED STATES

AGENCY AGREEMENTS

It appears that the transition in the use of gas storage in the US is only gradual, uneven, and incomplete, while there is clearly a transition from utility to commercial utilisation.[19] The most important reason for the incomplete transition may be that transactions are based on the bilateral model in an environment of diverse regulations and technologies in a geographically wide market. However, it should be noted that there has been an important development in the market, which is believed to be Pareto improving. The market has developed a tool to allow for the partial commercialisation of storage assets, even those held by and for regulated utilities. The tool is the Agency Agreement.

In a reliably liquid gas market, the decision to hold storage becomes a commercial decision. Those who believe they can profit by buying when prices are low and selling when prices are high will find storage capacity valuable. Those that either do not have the skills necessary to profit from price volatility or who are not able to profit from it due to their regulatory or business environment will be better off simply buying and selling gas in the market as their needs change. Utilities that have a regulatory obligation to ensure reliability of supply and minimise gas costs to firm ratepayers will need to maintain storage contracts. Storage is not only used for operational balancing by utilities, but also to help mitigate market volatility and reduce the impact of price spikes during the winter heating season to customers.

[19] In this section, the utility use means that gas storage is used for operational purposes to promote some other business objective, as opposed to the storage use for commercial applications where its profitable use is itself an objective. This section draws on the discussion presented in the American Gas Association [2001].

Agency Agreements, in the simplest form, allow a gas marketer to use the storage and transport assets held by a utility. The terms of these agreements vary widely. In some cases, the utility effectively turns over complete control of upstream assets in exchange for a city gate delivery gas supply. Essentially, such an agreement returns the utility to the pre-Order 636 environment of as-required merchant delivered gas supplies, except that the supplier is a marketer rather than the regulated pipeline. In these cases, the compensation to the utility may come in the form of reduced demand charges, profit sharing with the marketer, a negotiated fee, or a lower delivered gas cost. The marketer gains access to the storage and transport assets, which they can use to serve additional customers. The marketer can then commercialise the assets.

In other cases, the Agency Agreement calls for a split in the control of the asset between the utility and commercial functions. In these agreements, the utility maintains some control, such as specifying injection rates or target inventory levels, and the marketer is able to utilise the remaining flexibility to create value. Typically, there is some profit sharing arrangement between the marketer and the utility for the use of these assets. These kinds of arrangements allow the utility to gain value or participate in certain marketing transactions that they could not do alone under their regulatory requirements. The marketer gains the opportunity to profit by commercialising assets that would otherwise be unavailable.

Agency Agreements have two additional benefits. First, they allow for the gradual and limited transformation of access to storage capacity from utility use to commercial use. Individual storage facilities, and in fact individual storage contracts, can be split between these two different uses. Significantly, that split can evolve and be adjusted over time as the market evolves and changes. The second advantage is that Agency Agreements tend to reduce the pressure to overbuild storage and transport assets. Without these types of agreements, marketers might contract for new capacity while utilities hold on to existing capacity. Instead, Agency Agreements create a hybrid asset by sharing the same capacity and utilising it more efficiently.

Deregulation of retail gas markets and customer choice programmes also have an impact on the rate at which natural gas storage use becomes more commercialised. These programmes shift some or all of the responsibility for gas supply from the local utility to marketers, sometimes including an unregulated affiliate of the local utility. As the responsibility for supply is shifted, so is the use and control of the upstream assets needed to deliver that supply, including pipeline transport and storage. Since the marketers typically operate in a number of different market areas and without the constraints of regulatory control, they can use the assets in a more aggressive way than the individual local utility.

Reflecting all this market development, Table 14 shows the changes in control structure of natural gas storage in the US. Discussions about each market participant follow in the sections below.

Table 14 Market Players and Shares of Working Gas Capacity in the U.S.

% shares

	Ownership	Contractual Control	Effective Control
Pipelines	65.9	8.0	7.4
LDCs	30.5	73.3	65.8
Marketers	-	15.3	23.8
Generators	-	3.1	2.6
Others	3.6 1)	0.4	0.3

Note: 1) For independent operators.

Source: American Gas Association [2001].

PIPELINES

Although pipeline companies own 66 percent of the total working gas capacity, the majority of this capacity is under contract to others. It is reported that about eight percent of the capacity owned and operated by pipelines is used by the pipelines for operational balancing. The remainder is contracted primarily to LDCs. Open access and the elimination of merchant gas sales mandated by the FERC Order 636 rendered the pipelines' storage operations largely becoming warehouse operations. However, pipeline companies are looking for additional ways to use the storage capacity under their control. Examples of new flexible-rate pipeline services that explicitly or implicitly utilise storage capacity include paring and lending services and within-day and hourly nomination services.

LOCAL DISTRIBUTION COMPANIES

LDCs own and operate about 31 percent of the total working capacity and are the primary contract holder of the storage capacity of pipeline companies, keeping 73 percent of total capacity under ownership or contractual rights. LDCs utilise storage capacity primarily located in the market area for seasonal loads, daily operational balancing and emergency backup. However, many of them have seen value in the tools available to marketers to utilise storage capacity, turning over effective control of the capacity to marketers.

Under the bilateral trading arrangements in the deregulated gas market and given the statutory requirements regarding supply obligations, the main objective of LDCs in utilising gas storage is providing supply security and peak day coverage and price arbitrage. Also, LDCs use storage to minimise pipeline capacity requirements, to provide balancing, and to avoid imbalance penalties.

GAS MARKETERS

The regulatory changes that led to the commoditisation of natural gas created the environment in which gas marketing companies were born.[20] They apply risk management tools and location- and time-based arbitrage mobilising various transport and storage services. Due to the value addition potential of gas storage, these market participants have increased their effective control of storage capacity from nearly nothing just a few years ago to nearly a quarter of all capacity today.

The evolution of balancing rules has contributed to the entry of larger gas marketers into the storage market as developers, clients and agents. They profit by bundling the storage service in complete gas supply packages that cater to the end-user needs. The marketer typically offers gas supply services in multiple markets, spreading the cost of storage over all sales volumes and creating efficiency that is unavailable to a single user operating in a solitary weather pattern.

The furious competition among marketers has squeezed sales margins through aggressive, competing pricing strategies focused on high volumes. Gas marketers apply assets to the gas supply, maximise leverage on flowing gas, and re-bundle as much premium service with their gas supply sales as possible. Value-added services offered by marketers using storage capacity include swing, balancing, contract warranty and emergency supply. Gas marketers also offer such price hedging tools as price caps (limits on the maximum price regardless of market conditions) and cap and collar arrangements (limits on the maximum price coupled with a minimum price) to LDCs and end-users. Futures and option market tools coupled with gas storage are often used to reduce the risk of offering these services.

INDEPENDENT STORAGE DEVELOPERS

Independent storage developers are those developers of gas storage facilities that are not associated with LDCs, pipeline companies or other oil and gas companies. As unbundling and

[20] American Gas Association [2001], p. 30.

deregulation decoupled storage from other gas supply services, entrepreneurs became interested in the profit opportunities offered by storage. These firms, through their gas marketing and trading affiliates, utilise multi-cycle high deliverability storage to execute gas pricing arbitrage strategies and hub-to-hub trading activities.

Like gas marketers, independent developers have the ability to take advantage of location- and time-based price arbitrage together with least-cost gas supply practices, and to develop an asset from which to sell value-added services. They can optimise the capabilities of their facility by utilising capacity contract with others, on an interruptible basis, when the contacting parties do not use it.

ELECTRICITY GENERATORS

FERC Orders 888 and 889, which mandate open access to electricity transmission systems and separate pricing of generation and transmission, allow electricity users to choose the lowest-cost electricity provider, which in turn prompts competition among power generators. The deregulation moves in power and gas markets afford more opportunities for LDCs, gas marketers and gas producers to sell re-bundled gas services, including storage, to electric generators. Gas storage can be the most secure economical way of delivering gas at variable hourly rates as demanded by power plants.

THE CASE OF OPERATIONAL GUIDELINES BY THE UK'S TRANSCO

The Transco Operational Guidelines set out the operational guidelines which Transco is required to establish for the purpose of identifying the various balancing measures available to it and the basis on which it will employ particular balancing measures during any day.[21] The Special Condition of the PGT Licence requires Transco in carrying out balancing measures to achieve efficient and economical operation of its pipeline system and effective competition between gas shippers in the supply of gas by means of its gas system. It is also required that the guidelines be consistent with trading arrangements that are reflected in the Review of Gas Trading Arrangements (RGTA). If and when provisions in the Network Code are amended, it may become necessary for Transco to seek a modification to the relevant principles and balancing measures in the guidelines so that they remain consistent with the Network Code.[22]

The document consists of: a number of general principles surrounding its development and application; the circumstances and the basis on which Transco will utilise specific balancing measures; the various balancing measures available to Transco; and the balancing considerations in the context of a gas day and a set of balancing hierarchies. Although the guidelines specify various circumstances and measures for balancing, they are not intended to be prescriptive of every possible operational situation that is likely to be encountered by Transco. Considerations of operational practicality and safety prevent such treatment. (p. 1)

[21] Although the discussion attempts be a general one, it draws on version 6.1 of the guidelines released in August 2001 for specific developments in the balancing practices.

[22] A 'Network Code' is a legal document which forms the basis of the arrangements between a Public Gas Transporter (PGT) and the Shippers whose gas it transports. Currently, Transco is the largest PGT and covers almost all the gas transport networks in the United Kingdom. The Network Code itself consists only of the Principal Document and any Transition Document currently in force while supported by a number of other documents. Transco, Network Code-the Summary, p. 4.

GENERAL PRINCIPLES

Transco should establish the guidelines in a manner consistent with its statutory obligations to develop and maintain an efficient and economical pipeline system to transport gas to avoid undue preference or undue discrimination in the connection of customers to the system or the transport of gas through its gas system. Another regulatory obligation of Transco in carrying out the balancing measures is to take all reasonable steps in accordance with the guidelines. This is to prevent Transco from taking balancing actions at its own discretion to produce market outcomes that are inefficient or unfair.

However, as mentioned, the guidelines are not intended to set out the particular balancing measures to cope with every possible operational situation. Rather, it is recognised that under certain circumstances it is necessary that Transco depart from the balancing hierarchies. The principal reasons for departing from the hierarchies specified in the guidelines are (p. 3):

- where circumstances exist where not to do so would prejudice the interests of safety;
- where operational information indicates insufficient time is available to employ particular measures in accordance with the relevant hierarchy if balancing is to be achieved; or
- where the guidelines have been shown to be inappropriate and guideline modification procedures have been implemented but not completed.

Though shipper nominations and renominations are not viewed as balancing measures, interruption and constrained LNG constitute additional balancing measures available to Transco.

TRIGGERS AND HIERARCHIES

According to the guidelines, balancing decisions will be made based on a series of triggers. The triggers will in turn be based on the physical and commercial circumstances prevailing at any time. Any balancing actions will be taken in accordance with a particular hierarchy, unless the need to maintain system safety considerations requires Transco to do otherwise.

There are three categories of actions affecting the condition of the system that can be taken by Transco and users on any 'gas day', which are the following:

- Actions that can be taken by users which affect overall system balance. These include the making of nominations before each gas day and through renominations during the gas day to the extent that these adjust system inputs and outputs;
- Actions available to Transco which may avoid balancing measures and which include use of NTS compression and linepack; and
- Those balancing measures which can only be taken by Transco.

A national requirement to use balancing measures, which embraces the entire NTS, is triggered where forecasted end-of-gas-day NTS linepack levels are anticipated to move outside ranges determined by Transco. On the other hand, a localised requirement (capacity constraint) to use balancing measures which are targeted at a specific location or locations of the NTS is triggered in the event where projected key pressures are anticipated to fall below or exceed a safe value.

In order to address national deficit, Transco mobilises balancing measures in the following order:

(i) Go to On-the-Day Commodity Market (OCM).

(ii) Supply-demand interruption if demand is greater than peak-day demand and there are no bids available on the OCM.

(iii) Following supply-demand interruption, Transco returns to the OCM and accepts any bids that have become available as a result of interruption.

(iv) Reverse 1:50 storage monitor countering actions: Top up manager would counter shipper storage withdrawals with injection into top up to stop the flow of gas out of storage.

(v) Programme Operating Margins Gas (OMG).

To support key NTS pressures at appropriate levels, compression is employed and, where possible, NTS offtake profile rate is varied for limited periods of time. If NTS pressures are projected to fall below key NTS pressure requirements due to a localised capacity constraint, supply deficit or plant failure, a localised requirement is triggered. Depending on the type of localised requirement, the order of measures being employed differs.

At first, when the localised requirement arises from a gas shortage, the balancing measures are relatively simple: obtain gas from the OCM first; and use the OMG if more gas is needed. When the requirement is from plant failure such as compressor trips and pipe breaks, Transco compensates gas with its own, OMG.

As in the case of supporting NTS pressures, compression (to reduce upstream NTS pressures) and varying NTS offtake profile rate are utilised before a localised requirement of input capacity constraint is triggered when pressures exceed or are anticipated to exceed maximum operational pressures. The guidelines provide that an input capacity constraint will be resolved by the scale back of interruptible entry capacity until midnight within gas day and, if necessary, the buy back of firm entry capacity (p. 9). If no buy back bids are available, a terminal flow advice will be issued to curtail flow and users will be compensated according to the provisions in the Network Code.[23]

DISCUSSION

Let's briefly discuss the cost implications of various balancing measures. It should be noted that cost characteristics cannot be determined accurately due to the lack of data for each and every balancing situation on the one hand, and that one-size-fits-all conclusions cannot be drawn, on the other, because the UK system is only one of the many existing gas supply systems. Cost and benefit characteristics of balancing actions depend more on market situations and system conditions than on investment and operating costs of balancing measures. In this sense, we may not say that social cost is minimised or social benefit is maximised by employing the balancing measures and hierarchies provided in the guidelines, since Transco's balancing incentives do not wholly represent social interests. We may only infer cost structure for different balancing situations assuming certain objective functions for Transco and the regulator.

In the section of the guidelines on requirements to employ balancing measures and hierarchies, it is stipulated that the timing and extent of the balancing action take account of commercial and physical drivers, while at the same time maintaining system security. That Transco takes account of both operational and commercial considerations can be modelled as a profit-maximisation problem under the constraint of system security. Since Transco was privatised, there have been several institutional changes to accommodate Transco's energy balancing incentives. This implies that system balancing is no longer achieved with cost minimisation as the only goal given a level of system security. It is the implications of the changed Transco incentives that need to be brought to the regulator's attention. More specifically, Transco is now a competitor against system users for capacity and gas in the market, while it is still in charge of system operation.

[23] The Terminal Flow Advice is a similar tool to the Operational Flow Order in the US system of operation that is issued to curtail gas flow.

We see that compression is employed first to maintain NTS pressures, which implies that compression may be regarded as a technology which is dispatched as something similar to a base-load plant. Since this happens before any balancing requirement is triggered, compression is comparable to base-load plants in an electrical system.

The guidelines state that to the extent defined by the end-of-day linepack target bandwidth, Transco will seek to utilise linepack as a means of avoiding the employment of other balancing measures. Linepack is in this sense not regarded as a true balancing measure by Transco (p. 13). However, considering that balancing measures are taken only when certain balancing requirements are triggered, linepack is also a kind of base-load plant that is always employed.

The fact that changes in the NTS offtake profile rate for limited periods are used to support NTS pressures implies that this technology is one of intermediate-load plants that are dispatched later than compression. The additional cost element in the changes of NTS offtake profile seems to lie in the costs incurred by supply points to adapt to the changing offtake rates, which is a kind of outage cost on the customer side.

The use of OMG will be triggered by a national or localised requirement which cannot be met from the OCM. Typically, OMG is used to maintain system pressures in the period before other balancing measures become effective. OMG is also used to support system pressures on the gas day in the event of a compressor trip, pipe break or other failure or damage to transmission plant. A quantity of OMG will be kept in reserve to manage the orderly run-down of the system. The opportunity cost or insurance value of using OMG is deemed to be high due to its relationship to emergency procedures that have high cost implications to the whole system. It can be said that OMG is normally more expensive than gas from the OCM not only to the system operator, Transco, but also to the system as a whole and to society, since the guidelines are overseen by the regulator on the assumption that the regulator minimises the social costs of system operation.

Interruption is normally called before OMG or Constrained LNG is used. When forecast demand increases to a very high level, currently 85 percent of system 1-in-20 peak-day firm demand being the threshold, the transport system is deemed to have reached its full capacity and becomes reliant on strategic storage at certain locations, primarily LNG, to deliver gas to customers. At this stage interruption may be called by Transco to reduce demand, as it is uneconomic to use LNG to supply interruptible customers.

Whereas shipper nominations and renominations are not viewed as balancing measures, interruption and constrained LNG constitute additional balancing measures available to Transco. In designing the system, Transco has assumed that interruption would be used in preference to LNG, thereby minimising the investment in LNG facilities. Consistent with this, it is intended that interruption would be used prior to LNG. However, due to the lead-time needed for interruption, it may be necessary to use some LNG for the system's immediate requirements.

If, after interruption has been fully implemented, the requirement for LNG is identified before the day, then constrained LNG would be programmed to meet the requirement. If the requirement is identified within the day, then OMG would be used. If there still remained a requirement, constrained LNG would be used. All this implies that constrained LNG is a more expensive tool than operating margins. The extra cost of constrained LNG over OMG seems to come from the discount of capacity charge given to owners of the constrained gas which is not required for Transco's own OMG.

In the part of the Guidelines concerned with daily balancing considerations, it states that, on the gas day, the OCM will normally be used to maintain the system balance within a predetermined range during the gas day. Within the day, OMG is used before constrained LNG, which is in turn utilised before OCM. Before the day, constrained LNG is mobilised first, and then in order of OCM and OMG. All use of constrained LNG and operating margins LNG will be stopped before restoring interrupted load. It may be interpreted that, in terms of maintaining the system balance on the day, interruption is the cheapest option, OMG cheaper, constrained LNG expensive, and OCM most expensive. The reason why the dispatch order changes for the same sources of gas may be that within the day, for example procuring gas from OCM, meaning the spot market, is a more costly option than using own gas, because the gas price increases in the event of a constrained system. In a situation where the market is tight, it is cheaper to use own gas in store, which is a case that shows the value of storage.

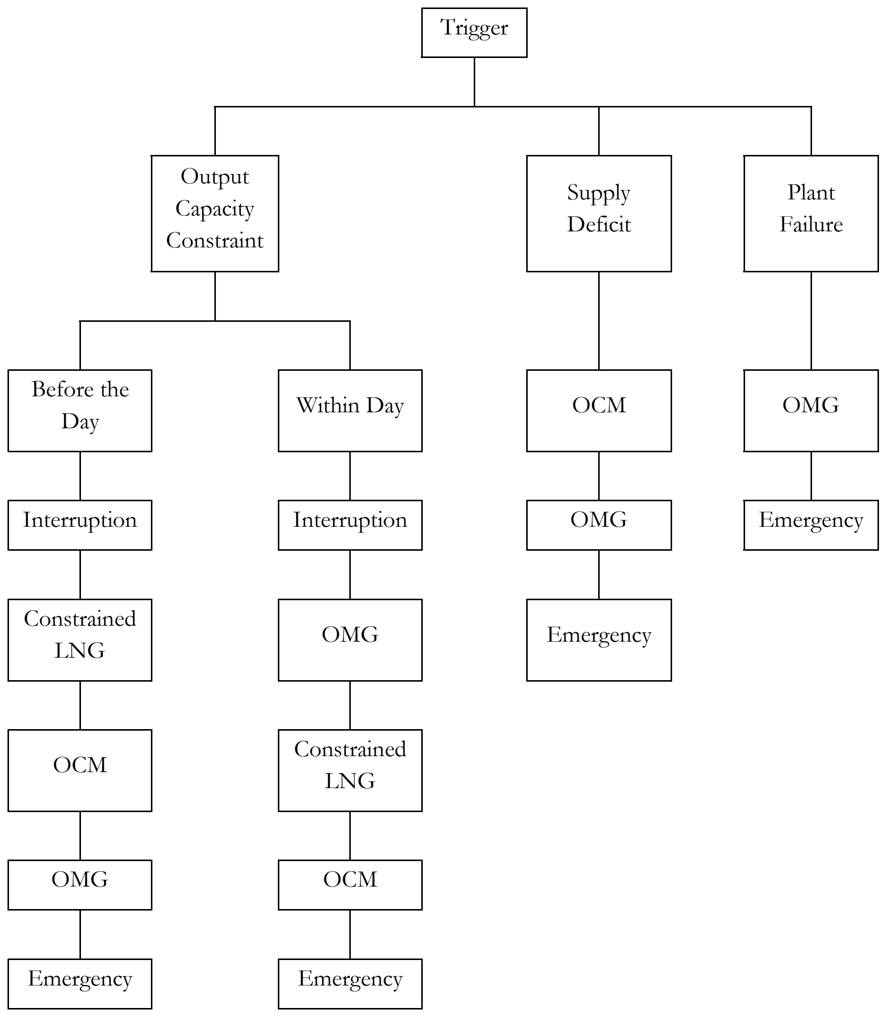
A fundamental question in this context is whether the cost characteristics of diverse balancing tools are consistent with what the theory of optimal plant mix predicts. Of course, Transco has certain criteria for utilising those tools based on operating costs and investment costs of assets. However, we know by now that cost comparisons depend in large part on market conditions and system conditions even within the general guidelines, apart from those under specific system conditions that the guidelines do not specify. For instance, localised system conditions cause different system needs and Transco relies on different merit orders: interruption first, and then OMG, constrained LNG and OCM within the day; but the order is different before the day.

It would be extremely difficult to determine whether actual dispatch corresponds with what the theory says, given the continuously changing system conditions and the market. In particular, the fact that some balancing tools are procured from the market makes it even more difficult to match the theory and actual balancing actions taken, because the market commands different prices for apparently identical services depending on the value of the services in specific market conditions. For instance, Transco has assumed that interruption would be used in preference to LNG, thereby minimising the investment in LNG facilities. Whenever interruption is insufficient to meet system requirements, Transco moves to the next balancing measure like LNG and OCM. This is consistent with the cost features that have been assumed in system design and consistent with the market mechanism. However, in the case of Transco nominated interruptible sites, overuse of interruption and under-investment in LNG capacity may have occurred. This possibility is reinforced to the extent that outage or shortage costs of those interruptible sites are not appropriately reflected in the system development by Transco. Furthermore, the competitive position of Transco against shippers in the market may exacerbate the situation.

Another implication of the practice in the UK system is that gas storage in a market where all trades are made on a commercial basis may not be a good tool to stockpile energy for an extended contingency at least under current technology. This seems to be particularly true with the economies that are dependent mainly on imported LNG as we see that LNG is the most expensive source of gas. Natural gas being a premium fuel, the market seems to compensate for high operating cost arising from high turnovers as well as high fixed costs. Facilities with high deliverability and high turn-around capability are valued more in the liberalised gas market. However, even ballpark cost figures of low-deliverability low-turn-around facilities do not appear to be able to allow stockpiling of gas to be viable unless the insurance premium for gas supply disruption is extremely high.[24]

[24] See Chapter 6.

Figure 10 Localised Requirement and Balancing Measures for Transco



Source: Transco [2001].

JAPANESE DISCUSSION ON TPA TO LNG TERMINALS

INTRODUCTION

As introduced in Chapter 3, there is a discussion going on about a new regime in the natural gas industry of Japan. A study group named the Gas Market Development Basic Issues Study Group has been formed within the government (METI) to develop a grand design for the gas market in 10 years time and a conceptual regulatory framework. The most noticeable topic in the list of the tasks assigned to the group from our perspective is TPA to LNG terminals. It seems that some concerns have been raised within the government and the industry partly due to the existing industry structure and partly due to the inherent characteristics of gas supply in the economy. Some of them may be relatively easier to resolve than others. Thus, in this section, we discuss a few of those issues briefly as they are still under discussion and many public consultations wait for their turn.

The boundaries between diverse energy markets have been blurred in Japan since the amendment of the utility industry laws for gas and electricity in 1995. The amendments allowed market entry by any energy company in the gas and electricity markets. Although some aspects of the new trading arrangements were unsatisfactory, particularly deficient information and non-transparent procedures for wheeling energy, it was a turning point in the history of the Japanese utility industry. More liberalisation and deregulation in both the gas and electricity markets were adopted in the amendment of laws on the electric and gas industries in 1999. However, there are still complaints in the industries about insufficient information on available capacity and transparency in the rate-setting procedures for wheeling.

Sending energy means that there is an origin and a destination for that energy. Typically, the origin of gas in a gas system like the Japanese is an LNG receiving terminal where LNG arrives from abroad, is unloaded from LNG vessels to LNG tanks, and is regasified and sent to consumption sites. Therefore, having no access to LNG terminals implies that a new entrant has to build its own terminal to import LNG or has to buy imported gas from other importers. Supply competition with already imported gas means that there is no competition at the stage of LNG import. This was the rationale for the recommendation by the US government for TPA to LNG terminals.

CHARACTERISTICS OF JAPANESE LNG TERMINALS AND STORAGE

LNG terminals in Japan are different in some respects from those of the US and the UK, which also utilise LNG in their natural gas supply system. As for ownership, Japanese LNG terminals are owned by vertically integrated gas utilities and electric utilities (see Table 7). As such, there are certain differences in terminal design specifics between the ones owned by gas utilities and electric utilities. On the other hand, LNG terminals and pipelines are not owned by vertically integrated merchant companies in the US, but typically by subsidiaries of energy holding companies. Since terminals are designed and constructed to supply both to power plants and city gas consumers at the same time, it does not matter whether LNG is used for power generation or city gas.

In Japan, despite the minimal production of indigenous gas, with less than a six percent share as city gas feedstock, gas utilities have no alternative to LNG. Therefore, they have to keep a certain amount of spare storage capacity and spare LNG to meet seasonal demand.[25] In contrast, LNG is playing a supplementary role in the US and the UK, where LNG storage is located in consuming areas and used for peak shaving. In addition, punctuality of LNG cargo deliveries is critical in Japan especially in the winter season, while it is not a significant issue in the UK and the US. In this regard, there arise concerns about how to adjust and coordinate LNG delivery schedules of terminal users, also taking into account production and shipping schedules and ship availability, in the event where TPA to LNG terminals are allowed.

Another important feature of the Japanese natural gas industry is that regional monopoly areas are not connected with other areas through trunk lines. This physical structure of the market was born by the regional monopoly franchise tradition. But this physical characteristic has prevented the formation of a national gas market in Japan, at least until now. Without a nationwide trunk line network, access to LNG terminals is a prerequisite to effective competition, considering the limited competition with imported LNG made possible by TPA to regional pipeline systems. Although it is reported that new entrants suffer from defects of trading practices such as problems of information availability and transparency in the assessment of access fees to pipelines, these problems are per se those of degree and scope of competition-facilitating tools given the market framework for competition. More significant is the opening up of essential or bottleneck facilities,

[25] This is also true with Korea. Until pipeline natural gas is introduced, LNG will remain the major reasonable option for feedstock of city gas and fuel for gas-fired power plants. The role of LNG in the environment where both LNG and PNG are used will change, which is beyond the scope of this study.

which is TPA to LNG terminals in this context. As long as a general framework is agreed, specific trading arrangements can be designed so as to make the market workably or effectively competitive.

ISSUES AND CONCERNS

According to Hasegawa [2002], the main issues and concerns in introducing a TPA regime in the LNG terminal business are the following:

- judgment of available capacity for TPA use and, especially, how to reflect the capacity needs to meet seasonal demand in the access fee;
- availability of spare capacity of vaporiser and send-out pipes, particularly during peak periods;
- adjustment of annual delivery schedules of LNG ships for TPA;
- compatibility of LNG ships for TPA with the existing LNG terminals;
- segregation of LNG storage tanks by the origin of import; and
- how to deal with BOG (boil-off gas) in storage tanks.[26]

Considering that introducing TPA to LNG terminals in Japan (and Korea) is at an experimental stage, the concerns listed above are understandable. In particular, if the existing utilities that own LNG terminals are to assume the default service obligation, designing a competitive market will be a formidable task. Crew and Kleindorfer [2002] conclude that this kind of problem is not well understood and awaits a workable solution. However, having a large and unique gas supply system, Japan might provide a model that could contribute to the development of a competitive gas market in which almost all gas supplies are from outside the system and there are few underground storage facilities.

It seems that the latter three issues are relatively easier to resolve than the first three, since the latter involves pricing of and investment in capacities, and changing existing terms of import and shipping contracts. The concerns about segregation of storage tanks by import origin and compatibility of ships with terminals might be mitigated if swap trading was allowed between gas importing companies. Also, the BOG sharing issue may be a minor one if gas volume (or quantity of energy) is measured from the consumption side and not from the supply side at LNG tanks.

The first three issues all boil down to pricing and contracting. In principle, correct (peak-load) pricing and transparent trading arrangements tend to reduce distortions in energy consumption and to invite appropriate investment in capacities. It may be useful to remember why the deregulation of utility industries was initiated and diverse supply functions unbundled in the first place in economies that have deregulated their utility markets. It was to redistribute rents that had been attached to the assets for supplying utility services. A TPA regime that allows only negotiated access on an individual contract basis is not generally regarded as transparent. Terminal owners will always be tempted to favour their own trading arms at the expense of third parties. None of the component services that are provided bundled will ever be priced at its cost, leading to over- or under-investment in the provision of those services.

At an early stage of developing a new market framework, it is unclear whether the possibility of capacity trading is seriously considered. That the possibility of allowing a secondary market for capacity is not being seriously considered should surprise nobody under circumstances where only limited access through negotiation is under discussion. However, it is well-known that having only a primary market for residual capacity does not help to facilitate competition or improve the load factor of facilities. Crew and Kleindorfer [2002] argue that piecemeal implementation of deregulation policies and failure to recognise rent-seeking behaviour have been the main cause of

[26] Japanese gas and electric utilities share some gas storage tanks and BOG is usually used to fuel gas-fired power plants.

the general failure of deregulation, particularly in the recent California electricity crisis. It would be useful for market designers to assume that every market participant and the regulator or government in general can reasonably foresee how they and others will respond to changing environment and to each other. It is probably incumbent market players rather than regulators, who know better the consequences of a given set of deregulatory policies. Kahn [2002] puts it in a different context:

> '[W]hat we intended to be a gradual process of deregulating the airlines soon took on a life of its own, like the proverbial snowball rolling down a hill…' (p. 36)

The Japanese government and IEEJ seem to share the view that TPA to LNG terminals would be an option to enhance gas market competition between densely inhabited districts (DIDs), which are not connected through trunk pipelines, as long as a nationwide trunk line network is not completed and LNG imports are destination-free.[27] However, TPA or open access to LNG terminals is equally or more important in Japan even when a nationwide trunk line network is completed. The reason is that, in a gas system like the one in Japan, an LNG terminal works not only as an unloading facility for imported LNG but also as a storage facility. That is, without access to storage capacity, the ability of third-party gas shippers to manage their gas commodity is extremely limited, which leads to a crippled competitive market.

One of the policy prescriptions that are presented is to increase potential natural gas demand in DIDs through fuel conversion (to natural gas) of existing thermal power plants in order to enhance competition between DIDs through TPA to LNG terminals. New investment in gas-fired power generation capacity has also been recommended. However, the rationale for the prescriptions seems to be only partly correct. It sounds as though demand must be larger to induce more supply, or the gas supply business should be profitable for it to attract new supplies. The statement, however, is trivial. If the economics of a business are good, suppliers will come into the market. From the perspective of consumers, they do not want to invest in gas-consuming equipment, especially vastly expensive assets like power generation plants, unless the fuel is sufficiently available at a reasonable price. Essentially, TPA and deregulation in general are supply-side issues. More supply at cheaper prices through competition is at the centre of all discussions of deregulation. Policies for increasing demand without fostering a sufficiently competitive environment may well keep and even enlarge the rents accompanying supply assets within the supply side. Effective supply competition in the gas market would be followed by higher utilisation rates of existing plants and addition of gas-fired generation capacity.

NATURAL GAS RESTRUCTURING IN KOREA

CURRENT RULES OF SYSTEM OPERATION

KOGAS CENTRAL SYSTEM CONTROL

KOGAS Central System Control consists of two teams, namely the System Control Management Team and the System Control Operating Team. In turn, the former consists of the administration section and the facilities management section, while the latter is composed of the technical planning section and the control section.

The main tasks of the Central System Control Office are:

(i) Remote system control

- Overall control of production and supply system

[27] Hasegawa [2002].

- Controlling supply pressure and 'sendout' gas quantity
- Analysing supply capacity of nationwide gas supply network

(ii) Prevention of accidents and contingency control

- Taking measures against contingencies
- Assuming area control centres' functions in case of contingencies
- System repairing in case of contingencies

(iii) Data processing

- Planning daily production and supply quantity of gas
- Analysing demand pattern
- Providing online information on production and supply

System control is undertaken by the Central System Control Office and the Area Control Centres. Their main work scope is shown in Table 15. The Central Office is connected with Area Control Centres and LNG terminals through a wide area network.

Table 15 Work Scope of Control Centres of KOGAS

	Central System Control	Area Control Centres
Normal Operation	Monitoring and ordering of nationwide trunk line network	Monitoring and controlling area trunk lines
Emergency Operation	Nationwide overall contingency measures Backing up area control centres	Contingency measures
Supply Management	Monitoring and ordering of sendout quantity from LNG terminals	Controlling pressure and flow quantity at metering points

Source: KOGAS [2000].

SYSTEM OPERATING RULES

KOGAS System Operating Rules are applied to the KOGAS system supplying gas to the city gates and large customers like power generators, but not to the local distribution networks which are owned and operated by LDCs. Current rules are not concerned with any commercial aspect except that KOGAS fulfils its supply obligation specified in supply contracts with customers while maintaining system pressures within safe bounds.

The document of the rules consists of five chapters and 29 articles. They define the terms used in the document and stipulate general rules and principles concerning gas system operation, pressure adjustment and procedures in accident and emergency situations. All the provisions regarding system operation are only declaratory in nature and details not specified in the document are delegated to relevant manuals (Article 30). Considering that detailed engineering procedures are delegated to operating manuals, the fact that any economic terms for trading in the market cannot be found in the provisions indicates that the rules are based on an engineering approach.

But it also has to be noted that it has not been necessary for KOGAS to optimise system operation economically in an environment where there is not a separately developed market for gas transport service and it is the only importer/wholesaler in the market. Although the KOGAS system is operated so as to achieve supply and demand matching while maintaining system pressures under engineering constraints, it is not clear what is the main objective of KOGAS in its system operation, for example, to maximise profits, social welfare as a public enterprise, or whatever. Consequently it is difficult to determine the efficiency of the merit order of system components in daily operation.

A CASE OF SPA NEGOTIATION FOR GAS FOR POWER GENERATION

As we saw in the previous section, in Korea, the rules of system operation are basically grounded on engineering considerations without commercial arrangements having been developed. This can also be seen from the tariff structure, which is classified on the basis of end-use types with the rate flat over the year, except for recent changes in the rate structure for large-volume customer sectors such as power generation, cogeneration and district heating.

Under these circumstances (one might assume that the circumstances were established by the supplier, KOGAS, and the regulators, the central and local governments), there are only fairly limited tools of demand-supply matching and system balancing. Local distribution companies just buy wholesale gas from KOGAS on a firm contract basis (with a ±10 percent margin) and resell the gas to retail customers as long as there is demand. KEPCO and other large-volume customers are supplied as firm contract customers. Imbalances between supply and demand for gas for power generation (by KEPCO) are to be resolved through quantity and price negotiations between the supplier (KOGAS) and the customer (KEPCO) on an ad hoc basis, although they sign a sales and purchase agreement on a yearly basis in which monthly offtake is specified.

In this section, we briefly review a case where there was a serious concern about supply-demand imbalance of gas for power generation. Although it was not directly concerned with the short-term system balancing issue, it involves a problem with the deficient development of a commercial business structure in the gas market.

BACKGROUND

The difficult negotiation situation arose in the autumn of 1998, when the Korean economy had been having problems due to the 1997-98 Asian financial crisis. Due to decreased exports of goods and services and a slow domestic market, demand for electricity from January to August 1998 fell by 31.8 percent compared with the same period the previous year. In parallel, demand for gas decreased by 12.0 percent. It was projected that demand for gas would continue to grow slowly, which would make unavoidable a significant supply-demand imbalance for the time being. It was recognised that a main reason was the take obligation under take-or-pay clauses in natural gas SPAs and that, even if KOGAS utilised its downward quantity tolerances fully, a significant supply surplus was unavoidable. Although we see that the surplus was overestimated at that time, it was huge, amounting to 13.4-15.5 million tons over the next five years. The choice between paying the take-or-pay penalty and how much and how to absorb the surplus was the biggest issue for the two biggest state-owned utility companies, the domestic supplier, KOGAS, and the main swing consumer, KEPCO, and the government at that time when they had to fix the yearly and monthly gas consumption volume for 1999. The then projected gas surplus is shown in Table 16.

Table 16 Korea's Gas Supply and Demand for 1999~2003 as Projected in 1998

thousand tons

Year	Demand			Fixed Contracted Import Volume	Surplus	
	City Gas	Power[1)]	Demand Total		A[2)]	B[3)]
1999	7,179	3,259	10,438	13,142	2,704	3,079
2000	7,988	3,246	11,234	14,596	3,362	3,616
2001	8,907	4,223	13,130	16,712	3,582	4,055
2002	9,879	4,684	14,563	16,980	2,417	3,046
2003	10,575	5,112	15,687	16,980	1,293	1,726
Total	44,528	20,524	65,052	78,410	13,358	15,522

Note: 1) Gas demand projection provided by KEPCO is that which was based on unconditional economic plant dispatch.

2) Yearly surplus compared to yearly demand.

3) Includes supply surplus arising from shortage of storage capacity and LNG delivery schedules.

Source: KEEI [1998].

SALES AND PURCHASE AGREEMENT BETWEEN KOGAS AND KEPCO

According to the sales and purchase contract between KOGAS and KEPCO, the yearly supply and consumption volume is to be determined through negotiation between the two companies based on a long-term electricity supply and demand plan and a long-term natural gas supply and demand plan approved by the government. When and if the yearly quantity cannot be agreed on, the average supply quantity over the past three years is applied temporarily. Thus, it seems that the problem of the two companies being unable to fix the quantity occurred due to a difference in their interests under the changed condition of gas demand and supply. It was pointed out that the biggest problem in the contract was that risk sharing between the companies under such circumstances as changing economic conditions was not well specified.

Although arguable, KEPCO presented its interpretation of certain clauses in the contract pertaining to the surplus problem. KEPCO denied the KOGAS's request for more gas offtake for the next few years by arguing that it could not fix quantities for future years because it felt the quantity should be decided year by year. Also, all other quantity negotiations other than for volume for the next year should be based on the long-term plans (a yearly offtake decision is hard to make several years ahead), so that it was not responsible for any surplus volume for future years. In other words, it argued that the quantities in the long-term plans were only forecast numbers, not contracted quantities, so that KEPCO would not share any responsibility for fulfilling the take obligation in gas imports.[28]

In addition, KEPCO's view of the reason for the surplus problem reflected its general dissatisfaction as a consumer with the KOGAS policies as well as government policies for the natural gas industry. Although KEPCO acknowledged that the problem stemmed from the unanticipated economic downturn caused by the Asian financial crisis, it also attributed it to the expansion policy for the gas market. According to KEPCO, while KOGAS attempted to enlarge the market mainly for space heating, it failed not only to construct sufficient storage facilities to meet the needs of the rapidly growing market, but also to develop customer groups with 'good'

[28] KOGAS makes a gas sales and purchase contract and establishes facilities construction plans taking the long-term electricity supply and demand plan into consideration.

demand patterns. Instead, KEPCO argued, KOGAS had relied too heavily on KEPCO's swing consumption in matching supply and demand. KEPCO suggested a few measures to mitigate the risk of potential surplus in the future, which can be summarised as:

- depart from the expansion policy for the natural gas market;
- refrain from relying on KEPCO's swing consumption for supply-demand matching;
- reflect uncertainties appropriately in procuring long-term LNG while using KEPCO's forecast demand for LNG only as a reference;
- construct a reasonable LNG storage capacity; and
- incorporate the feasibility of importing PNG in future gas procurement plans.

DISCUSSION

While the above suggestions made by KEPCO are at least partially correct, they also show a certain strategic stance and reflect customer needs on KEPCO's side. The practice was for KEPCO to change its gas consumption through negotiation with KOGAS when KOGAS asked it to do so. Some penalties and discounts were applied but only on an ad hoc basis without any clearly specified rules or formulae. The gas sales and purchase contract is in fact one of a firm service. For reasons including inconvenience and inefficient plant operation on the part of KEPCO, it had tried to become an LNG importer for own use, which was not legally allowed for some time and is still not permitted by the government even after LNG import for own use was legally allowed.

The Korean government wanted to keep KEPCO's role of swing consumer in the gas industry without allowing clear and transparent rules for penalties and compensation for it to develop in the market. The government and KOGAS wanted to enlarge the market base, but the main result was a rapid growth in residential demand, which had a large seasonal variation. The Korean government might have desired to maintain its influence on the market, for which stability was an important policy goal. Under these circumstances, it was not surprising to see a customer seek to escape from the role of a swing consumer. In other words, KEPCO might have not argued harshly against the KOGAS's marketing policies if gas purchases from KOGAS had been made on a commercial basis. Of course, this does not necessarily mean that KEPCO was perfectly commercial-minded.

The contention made by KEPCO that its forecast demand for gas should be used only as a reference in gas purchases by KOGAS was also beside the point. It is safe to say that KEPCO would not be willing to take the risk of a sudden increase or decrease in its gas demand at any cost. It would be extremely costly to procure LNG on a yearly basis (as in the SPA between KOGAS and KEPCO) without having an own gas storage capacity or any resale channel (it was legally impossible to do so) within national borders. It would only be economically feasible in a reasonably smoothly operating spot market for LNG. On these grounds, it may be said that KEPCO behaved strategically to enter the gas market as a supplier or at least to make terms of trade better.

Although the possibility of KEPCO's strategic move may be admitted, it is clear that there was much room for improvement in the Korean natural gas industry. KOGAS launched a programme for developing industrial demand, which showed 39.7 percent growth in 1999 and 30.7 percent in 2000 compared to 21.2 percent growth in 1998. The level and structure of gas rates has been changing to better reflect costs (see Chapter 3). Within the existing industry framework and trading arrangements, more supply facilities needed to be built, securing more favourable terms and conditions in LNG SPAs, more participation at the gas development stage was desirable, and fair and efficient risk-sharing in contingencies between KOGAS and KEPCO was required.

The difficulty in fixing the supply-offtake volume between KOGAS and KEPCO during the period of gas surplus shows that this kind of trading arrangement cannot be sustained for long for profit-seeking companies unless there are clearly defined transparent trading rules. The most important evaluation criterion for KOGAS and KEPCO is their profit level, both to the government and to the market, although other performance indicators are used such as sales revenue and other activities in the so-called public interest. So long as they remain within the public sector but are evaluated by the market, their profit motive will dominate the public interest in business planning and daily operations. While KOGAS is proud of its activities as a public enterprise, it seems to be more proud of high profits and other indicators of commercial performance, even though a major part of the profits consisted of various compensation measures allowed by the government for the losses incurred during the crisis. A 10 percent after-tax allowed rate of return with no competitor in the market in addition to certain low-interest long-term loans and sliding scale indexation of LNG costs is bound to produce a 'good' performance indicator with no comparison.

It is not clear that non-transparent swing negotiation procedures and unclear compensation mechanisms involved can add to or reduce the social welfare as well as the profits of KOGAS and KEPCO. It is an empirical question whether KOGAS's storage capacity would have been installed at the optimal level, if it were not optimal at all, and whether it might have developed differently if the market structure had been different. But one thing that is clear is that there have been few choices for either consumers or suppliers in Korea with respect to price, gas commodity and supply capacity, whether intended or not. While the pipes are filled with gas and consumers use it at a specified price at any time of the year (except for KEPCO), suppliers and regulators have not been interested in creating more value to the market.

An issue related to the value addition by gas supplier and consumer is that, as mentioned earlier, the gas sales and purchase contract between KOGAS and KEPCO is only concerned with yearly quantity of gas, although there exists some margin of error for offtakes. The contract does not seem to be particularly concerned with any outage or shortage cost (for example, maintaining alternative plants) on the consumer (KEPCO) side. Of course, this cost may be reflected in the negotiation process on an ad hoc basis. But no specific articles on this issue can be found in the contract terms. It is agreed at least theoretically that disregard for the different elements of outage/shortage costs can lead to problems, especially since the costs of disruption (although it may not be referred to as disruption in this case) are known to be considerably higher than the loss in consumer surplus. Also, KEPCO's demand for gas may be envisaged to be downward sloping with kinks at the points where natural gas becomes competitive or non-competitive with other fuels. This means that KEPCO's willingness-to-pay for more gas and willingness-to-accept less gas than a planned volume are different because a large volume of gas is involved. It is plausible to assume that with a downward-sloping demand curve, willingness-to-accept less service is larger than willingness-to-pay for more service. In the above case, KEPCO was asked to use more gas by KOGAS. However, the usual practice is that KOGAS compensates KEPCO for the differential with alternative fuels. All these considerations suggest that KEPCO's argument about the deficient storage capacity construction has some foundation, although it does not seem to have recognised this problem.

DRAFTING OF SYSTEM OPERATION RULES IN RESTRUCTURED MARKET

According to the development of the trading arrangements and the drafting process of the new system operating rules, Korea seems to follow the poolco model for its natural gas market. Although it will take more than a few years to have a fully competitive natural gas market, it is envisaged that the import-wholesale sector of the industry will work in a competitive setting from

2003. Discussions are still going on, mostly about the issues of facilitating effective competition and stable prices for captive consumers in the short to medium term.

The first thing to note in the development of the new arrangements is that interruptible supplies will be encouraged by way of discount schemes and others for the purpose of easier and more economic system operation. Thirty days per year is considered the maximum duration where supply can be interrupted for a customer.

Secondly, capacities of supply facilities are likely to be booked on a yearly basis. Although capacity release or a secondary market for capacities will be allowed, the prices in the secondary trades will be limited to a level determined in the primary contract in order to prevent system users from cornering capacities. However, this may have the effect of prohibiting the development of a liquid and competitive gas market.

Thirdly, since the natural gas industry restructuring in Korea is being undertaken only partially in the import-wholesale and bulk supply sector, the incumbent monopoly, KOGAS, will only be responsible to operate the supply facilities that are within its current scope of operation. Local distribution networks will be owned and operated by the existing local distribution companies. However, the gas supply system in Korea has been developed in such a way that there are significant network externalities. KOGAS's system operation in the new trading environment will inevitably give rise to many situations of conflict of interest between local distribution companies, leading to more needs of combined system operation or interconnection of local networks. This will be a natural consequence of the system operation in a reticulation type gas system and it will facilitate more efficient system operation. Under these circumstances, KOGAS or any existing or potential market players with significant market power may have incentives to take advantage of their position despite the presence of the regulator, who has been known to have less information and expertise, in the restructuring process.

For example, KOGAS might want to contract for gas supplies so that it may be allowed to maintain a subsidiary which is to support system security, in anticipation of a state where its market share in bulk supply will remain high. Or, KOGAS might push through an inefficient set of market operating rules, expecting a future change in the rules that is not only efficient but also more favourable to its business. Although the final result could be efficient and certain political and equity issues may prohibit the industry from going directly to the final state, some efficiency will be sacrificed by the manoeuvring over time until the change has been made. Examples are the proposal for the separate operation of the trunk lines and medium- to low-pressure lines and that for the establishment of gas exchange, which does not seem to be a useful trading house with only two or three suppliers without bids from the customer side. Also, it is said that gas supply contracts with electric generating companies, formerly under the umbrella of KEPCO, have not been amended in concert with the restructured electricity industry. As swing consumers, power generators can easily influence the new rules of the gas industry, if they wish to. At the local level in the meantime, local distribution companies may try to acquire adjacent local distribution networks, which may lead to more efficient system operation than in the past. Although these examples may be related to a more efficient gas supply system, they also involve the issues of market power and 'games' between market players and the regulator. This is an important policy issue in the future development of Korea's gas market, and a well-balanced design of trading arrangements and regulations is necessary.

CHAPTER 6

SOME POLICY ISSUES

COMMERCIAL CONSTRAINTS AND INCENTIVES

The development of commercial business practice is confined within legally allowed boundaries. The boundary of possible trading arrangements is set by government, though not a unified entity but in a broader sense covering legislation, administration and the courts. Under trading arrangements that do not permit market participants to seek profits in the most commercially profitable way, there will always remain inefficiencies and room for higher welfare. Put differently, so long as the government permits market players to send and follow right price signals, they will trade goods and services in the most efficient way and an efficient level of supply capacities will be provided.

Examples are not hard to find. At an international level, LNG buyers have been trying to construct an appropriate level of facility for LNG imports, storage and processing. One of the main determinants of the facility capacity has been the take-or-pay clause in LNG sales and purchase agreements. However, it is known that inefficient internal industry structures and regulatory regimes have resulted in deficient capacity and inefficient price signals, for example in Korea, leading to insufficient storage capacity and demands for more liberal gas trading arrangements.

On the other hand, in the US and the UK, where the natural gas industry has been liberalised for some 20 years now, market participants have developed a host of gas trading tools to make the most of the potential made available by deregulation. Among others, short-term trading needs of market players caused by more commercial trading arrangements like a daily gas balancing regime have contributed to the development of diverse marketing tools both in the physical gas market and in the financial gas market.

It is true that there are many policy objectives that government wishes to achieve through industrial policies, for instance, income redistribution through gas pricing policies. Also, government may intervene in the industry to enlarge the demand base and supply capacity so that, from the government's perspective, the market can accommodate competition. While there is some truth in this kind of reasoning in the field of policy-making, there are often trade-offs between the efficiency in the market in question and the policy objectives that government attempts to achieve through and within the market. Particularly, as government intervenes in the market, market participants will always try to seek more rents, taking advantage of the details of regulatory provisions, leading to more regulations, transaction costs, and more deadweight losses, which are real resource expenditures.[29]

INTERRUPTION AND STORAGE

Although a gas system operator (or public transporter in the UK or pipeline company in the US) can meet its security obligation by providing sufficient pipeline capacity to cover all peak demand, this is an inefficient way of meeting the obligation. There are more efficient ways, such as increasing supply or reducing demand in the area of greatest demand, especially considering long distances between supply sources and consuming areas. The two major alternatives to investment in pipelines capacity are interruption and strategic storage.

Interruption is a short-term measure given capacity. As such, forecast of interruptible loads come into the planning of system development or expansion. Interruption is operated through gas

[29] More discussion of government intervention in the gas market is presented below.

flow (gas always flows along facilities and it needs physical capacity). However, supply interruption may occur even when there is excess transport capacity. In this case interruption operates as an alternative to extra supplies from swing gas or seasonal storage. This form of interruption is less likely to be location-specific as it is called on to ensure net system balancing.[30]

It is reported in the case of the UK that, although both interruption and LNG are used, the former has some advantage over the latter, from Transco's perspective, in that it is located in every LDZ, providing greater flexibility at a lower cost. It is said to be more economic, from Transco's perspective, to grant discounts on transport charges to customers who are willing to stop burning gas temporarily, than to build the additional capacity needed to provide all sites with firm supply. However, it should be noted that a socially optimal choice depends on the social costs of achieving the objective of meeting system security obligations. As the market for gas develops such that it contains more sub-markets for gas and other services, comparative cost figures may change across the alternatives available to the transporter or system operator and, consequently, their choice. A little more discussion about this point with a comparison of the use of interruption for balancing in monopolistic and competitive gas markets will be useful.

In a monopolistic gas market the incumbent monopoly is generally responsible for all areas of gas transport and supply, and, in return, it has security obligations in terms of both providing capacity and gas. Interruption may be called because there is insufficient capacity or gas to meet demand either nationally or locally. The monopolist, with complete control of the gas supply system, ranks the various means of meeting its obligations in particular conditions. Typical tools available to a monopolist in addition to interruption are year-round supplies from production sites, seasonal supplies from production areas, and seasonal and peak-shaving storages.

In a competitive market, shippers (system users) are typically responsible for meeting the obligations of system security, without particular system security obligations but with commercial incentives for balancing. They call interruption for themselves when market conditions allow them to earn profits by doing so, for example, for location- and time-based arbitrage. Shippers have a number of other tools for balancing through their supply portfolio comprising swing, spot or storage gas. Their reliance on different tools will also depend on their customer portfolio and commercial opportunities. Therefore, according to market opportunities, shippers will mobilise different options, and the remaining balancing actions and their merit order that have to be undertaken by the system operator will be different from those that had been employed in the monopolistic market.

Interrupting the gas supply of a power station may have significant implications in the electricity market. Dual-fuel facilities may require large initial investment. There may also be costs associated with the process of switching fuel. Other factors such as emission control may require a certain pattern of fuel use. There may be other costs created by interactions with other markets, such as coal and fuel oil markets or the market for electricity generation. The costs of interruption for individual customers vary greatly depending on all these factors. In the process of developing the New Gas Trading Arrangements (NGTA) in the UK, it was envisaged that the emergence of better market signals facilitated by the NGTA, particularly within-day gas and capacity prices, would help to assess the value customers place on interruption. At the same time, it was suggested that Transco must seek to ensure that interruptible transport discounts were sufficient to encourage customers to sign interruptible supply contracts.[31]

In Korea, the practice has been that KOGAS compensates KEPCO only for the difference in fuel costs when KEPCO was required to use fuels other than natural gas. This is one of the reasons why KEPCO became dissatisfied with the gas procurement process. Also, KEPCO was not supplied with gas as interruptible customer, at least contractually, but it was effectively treated as a kind of interruptible customer under the name of swing consumer, which was part of

[30] Madden and White [1999], p. 115.

[31] Ibid., pp. 132-133.

government policy for gas supply and demand matching. As discussed earlier, the policy of KEPCO's swing consumption has been the main cause of insufficient storage capacity in Korea. With a limited number of LNG suppliers under rigid terms and no contractually interruptible loads, KOGAS had to rely on KEPCO, the only swing consumer, for matching supply and demand in fulfilling their gas supply obligation.

LARGE-VOLUME DEMAND AND DEREGULATION

We may ask here why there are no or fewer interruptible loads in some economies than in others. Apparently, an economist's answer must be that the cost of having interruptible loads in the former is (prohibitively) higher than in the latter. Cost or value of an economic activity in an economy is determined by many factors such as culture, value system and government policies aside from material costs of actual production and trading. Government affects costs or value by placing (binding) constraints on people's activity or resources, creating shadow value or shadow cost attached to them. This shadow cost is absorbed by and distributed to all citizens, a distribution which is determined by demand and supply elasticities of the good in question and the bargaining power of the parties concerned. Bargaining power is not only endowed inherently but also redistributed by government policies and legislation. Government policies are affected by rent-seeking activities of interest groups, for example, gas suppliers in our context. In this regard, dissipation of rents was the core of deregulation initiatives in many economies. But dissipation of rents encompasses distribution issues and, for this reason, there remains a need for government intervention in the market. Once some regulations are put in place, however, they tend to induce rent-seekers to attempt to affect the structure for rent distribution, leading to more regulations.[32] This is a dilemma between total deregulation and regulation.

One implication is for the development of interruptible loads and, in a broader sense, (de) regulation in the demand side of natural gas. Large-volume customers can play a significant role in optimising the system operation and supply-demand balance of a gas system. Large interruptible loads can save a great deal of investment in gas supply facilities. Under strict regulation in the electricity sector, its demand for natural gas will naturally be restricted. While there may be huge and diverse demands, they cannot be realised due to regulations. Electricity generators will tend to need a variety of gas supply services to meet their load requirements, as the electricity market operates on a more competitive basis. On the other hand, stricter environmental regulations will tend to require power generators and large-volume industrial/commercial consumers to use more natural gas. Depending on the regulatory schemes on air pollution such as specific fuel choices or regulation of total pollution, their fuel mix and extent of becoming interruptible loads will differ. In short, regulatory schemes in the demand sector have influence over the effectiveness and success of deregulation on the supply side.

Government may develop large-volume demands through, for example, diverse incentives. However, as long as restrictive regulations remain on the demand side, only the total volume may increase without flexible demand patterns being developed. Only if gas customers compete in their product market and are granted free choice of fuels, will they react to deregulation on the supply side. In other words, simply enlarging the total volume of gas demand may not be effective to facilitate competition in the gas market.

Some argue for increased gas-fired generation capacity as a way of promoting competition in the Japanese gas market. As discussed above, however, competition and deregulation in the gas market are a supply-side issue. At least until now, there has been no discussion about demand competition for gas. The rationale for gas deregulation lies in the view that a competitive gas market supplies the same gas at a lower price or, in a strict economic sense, at right price signals. Or, suppliers in the competitive gas market supply a better gas service for at least the same price as previously. Increased gas demand for power generation through new generation capacity investment has little to do with facilitating competition in the gas market. A probable outcome is

[32] This phenomenon was named the tar baby effect by McKie [1970].

increased rents that will be imputed to gas suppliers. And without supply competition and resultant (actual or predicted) lower gas prices, power generators would not invest in new gas-fired generation capacity.

The government or regulator as constraint setter and rent distributor should note that gas supply interruption is not costless. If the costs are properly reflected in the price of interruptible supplies, an optimal level of investment in capacity will result. On the other hand, unless the costs are appropriately reflected in prices, under- or over-investment in capacity will occur. Under- or over-investment is not only inefficient in the sense of causing social loss but also raises a distribution problem. In the process of reaching an optimal level of capacity, under-investment shifts rents from consumers to suppliers or asset owners, and vice versa, although the rents themselves work as signals for new investment opportunities.

SUPPLY SECURITY AND MARKET STABILITY

One of the major barriers to the commercialisation of the domestic natural gas industry, especially in gas-importing economies, is the government's desire to develop the internal gas market base and to secure stable supply. And governments in gas-importing economies have been successful in fulfilling these objectives. The point, however, is that supply security and market stability are achieved at certain costs. The costs appear as higher domestic prices caused by direct costs of more storage tanks and stored gas, and higher import price of flexible gas supplies. Indirect costs include more use of other fossil fuels than otherwise would occur, leading to, for example, more air pollution. The weaker bargaining position of natural gas buyers, particularly LNG buyers in East Asia, whether it was intended or not, resulting from demand for more secure supplies, may have possibly distributed more rents to sellers. However, as LNG supplies become more competitive thanks to technological progress and the employment of innovative financial products in the international market, opportunities are appearing for gas buyers to share rents in the form of more flexible terms of SPAs and possibly lower prices for the same gas than before.

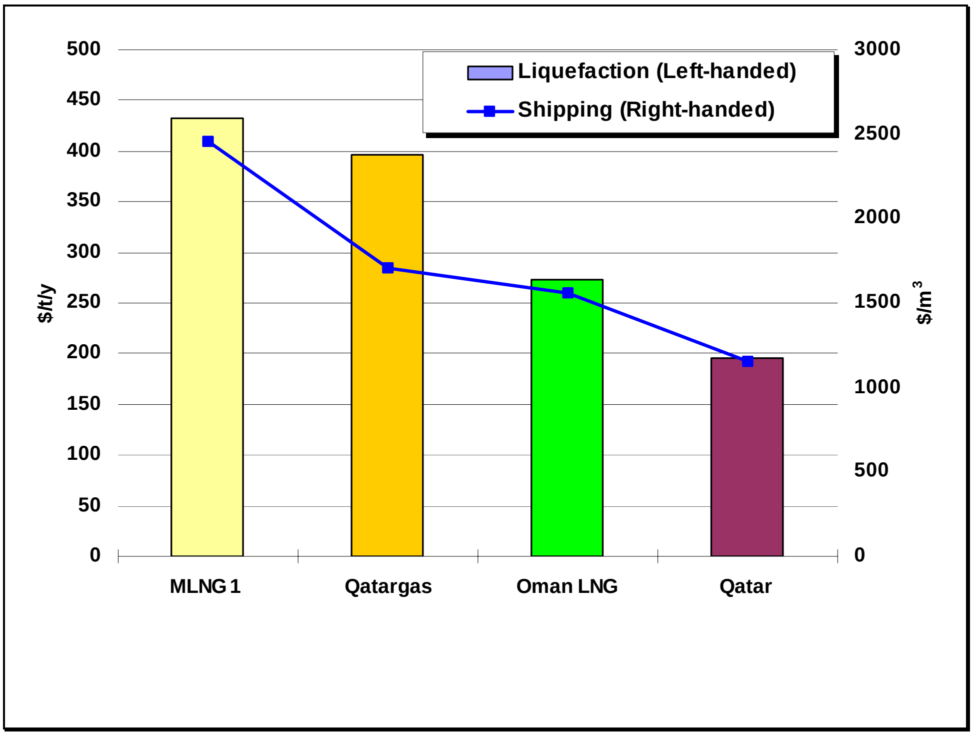
As the LNG market has matured, many changes have evolved in the gas chain. Upstream costs have been brought down by more diversified project funding methods, more competition in the EPC (engineering-procurement-construction) market, increased scale and design efficiencies in liquefaction, and shortened time periods for project development. It is reported that upstream costs have been cut down in the order of one-third in the last decade. Competition between LNG suppliers widened with eight operating projects, one project under development, six expansion projects and five grassroots projects in the Asia-Pacific Basin. Due to the competition between suppliers and to lowered LNG costs, particularly from expansion projects, suppliers become more willing to accommodate buyers' needs by, for example, early project commitment under more flexible terms.

Some estimate that 27 to 44 uncommitted LNG ships will be looking for employment in new long-term trades or in short-term trading by 2005, depending on the declaration of outstanding options in shipbuilding orders.[33] Also, short-term trading is expected to play a key role in employment of the uncommitted ships and in the development of the global LNG market. Short-term trading is regarded as an outlet for spare LNG production capacity and the only physical means of arbitraging different gas values in different gas markets. In addition to the flux of the fleet of LNG ships, ship size has been getting bigger, and is up to 145,000m^3, with 135,000m^3 being the typical capacity of new ships today, and shipbuilding costs have decreased substantially, resulting in even lower unit shipping costs. If this trend, combined with excess production capacity, continues into the future, there will be great room for short-term trading. By gaining control or access to shipping capacity with sufficient import terminal capacity, even LNG-

[33] See, for example, Adamchak [2001].

importing countries will be able to foster gas-to-gas competition within national borders more easily.[34]

Figure 11 Cost Reductions in Natural Gas Liquefaction and Shipping



Note: MLNG 1: 1983 grassroots project; Qatargas: 1996 grassroots project; Oman LNG: 2000 grassroots project; and Qatar: 2000 expansion project.

Source: Poten & Partners [2001a].

It is generally accepted not only that the current LNG market is a buyer's market with spare capacity available, more export projects and weaker shipping destination restrictions, but also that the LNG acquisition practice is changing. The traditional business model of one-at-a-time one-on-one negotiation was introduced by Japanese buyers and accepted by major project sponsors mainly due to the market share and financing support by Japanese companies in the early days of LNG markets.[35] However, as the market share of Japanese buyers will decrease with the LNG import by India and China and such new forms of financing as third-party funding for the Rasgas and Oman sales to Korea are utilised, it is likely that pricing and other contract terms will become more transparent and competitive, allowing LNG to become competitive against pipeline natural gas.

As LNG acquisition becomes flexible, LNG storage costs in internal markets will also go down, because the higher flexibility in LNG acquisition renders less need for storage capacity. This kind of flexibility may be regarded as a type of virtual storage in that it reduces the capacity needs of LNG buyers without additional storage facilities on the seller's side. Moreover, as the gas acquisition practice becomes more flexible to fit buyer's needs, buyers will seek ways to make ship-saving swaps to meet seasonal demand fluctuations and other uncertainties arising, for example,

[34] Nissen [2002] discusses the flexibility in LNG trades in general terms that are required to facilitate competition in internal markets of LNG-importing economies.

[35] Poten & Partners, Inc., "The Commercialisation of LNG Markets", *Fundamentals of Global LNG Industry 2001*, http://www.poten.com.

from internal market competition through short-term deals. Third-party LNG traders are anticipated to find a market under these circumstances.

Security of gas supply implies flexibility both in LNG sales and purchase and in internal supply system operation. The expanding LNG market has made possible technological progress in gas development and production and shipping, reducing delivery prices of LNG. More flexible LNG trade mitigates LNG storage capacity requirements in importing economies. In addition, third-party or open access to storage within national borders lessens the burden of LNG buyers having their own LNG storage, resulting in lower domestic supply costs of gas. This means that the rents attached to storage facilities are shared by storage owners and storage consumers. From the perspective of LNG buyers, the fulfillment of their gas supply needs at more flexible terms and at lower cost means that they can buy the same level of supply security at lower prices. Seen from a different angle, it implies that supply security is increased at the same level as willingness to pay for it. This is another form of rent sharing between sellers and buyers of LNG.

A question has been raised about the feasibility of gas stockpiling for the sake of energy security. Loosely speaking, however, gas stockpiling as in the sense of oil stockpiling does not seem to be an economic option. Natural gas is a premium fuel. It sometimes takes multi-billion-dollar projects to produce gas and transport it to markets. It is known that when natural gas is transported as LNG, it is at least eight times as expensive as oil per unit amount of energy.

According to different sources, the investment cost of LNG storage tanks alone is in the order of eight to 10 times higher than the total investment cost of crude oil storage and around three times higher than oil product storage on a unit energy basis.[36] The investment cost of underground gas storage per energy unit increases rapidly in the order of depleted reservoir, aquifer and salt cavity. The construction cost of depleted reservoir storage is comparable to that of a crude oil storage facility, and that of aquifer storage is comparable to oil product storage. Yet the cost is two to three times higher than that for oil products.

It is true that for a long time underground gas storage was developed for strategic reasons to provide access to gas volumes and capacities in case of gas supply shortage, especially in the event of war or conflicts. However, as gas has become popular and its consumption volume has grown rapidly, more emphasis has been put on the role of gas storage in meeting peak demand and economising the gas supply chain. The working gas that can be stored in a depleted reservoir typically ranges between 300,000 and five million toe and 200,000 to three million toe in an aquifer storage, which are comparable to the capacity of an average oil storage site. A salt cavity typically stores 50,000 to 500,000 toe of gas. Operating costs for gas storage are fairly high. But this may not be a crucial element if gas is to be stockpiled for contingency purposes only, since stockpiling does not require high turnovers of the gas stored.

The high investment cost of gas storage implies a huge opportunity cost of utilising storage facilities for stockpiling purposes. Unless the risk premium for gas supply disruption is sufficiently large, gas stockpiling does not seem to be a viable option relative to oil stockpiling. Natural gas being a premium fuel, the market seems to compensate for high operating cost arising from high turnovers as well as high fixed costs. Facilities with high deliverability and high turnaround capability are valued more in the liberalised gas market.

RENT SHARING AND RENT DISSIPATION IN GAS STORAGE

As we saw in the previous chapter, Agency Agreements between storage owners and marketers are becoming a popular business practice in the US and UK. The diverse arrangements in the agreements are regarded as Pareto-improving in that they contribute towards the fulfillment of supply obligation on the part of LDCs, towards higher utilisation of storage capacity of pipeline companies and LDCs, and towards more business opportunities and profits to the marketers. The core purpose of gas market deregulation was rent dissipation, which has existed in the transmission

[36] For oil and LNG tank costs, the figures of Korean facilities were used. See also tables 1 and 2 in Chapter 2.

and distribution of gas, and the liberalised market makes it possible for the rent to be distributed among facility owners and users and final consumers. It is safe to say that it does not necessarily imply that there are no excess profits to gas supply businesses and there would remain the need for a certain degree of regulation for consumer protection. However, it also shows that once the market is liberalised, it finds the most efficient way of satisfying most of its participants.

On the other hand, in the course of discussion about TPA to LNG terminals in Japan, concerns have been raised that 'excessive' competition brought about by TPA to terminals affects the cooperative procurement of LNG by electric and gas utilities.[37] Ostensibly, it is unclear whether the utilities argue that the cooperative procurement practice should be maintained. However, it is not surprising at all that the utilities prefer the convention of cooperative procurement of LNG to the uncertainties in the competitive environment. It is an empirical question how much rent Japanese utilities as a whole will surrender to LNG sellers, arguably in terms of supply security and lower LNG costs, in exchange for lower supply costs to end users that can result from internal competition. To the extent that there is a national consensus about positive net benefits in the Japanese market on cooperative procurement, Japan may retain the tradition. That is, so long as the gains from cooperative procurement are greater than those from a competitive market mechanism, the existing method of LNG procurement is justified. However, it should be noted that it is for the most part the end-users who pay the premium for security, while they do not have good information on how much security they are buying from LNG sellers through Japanese utilities.

Many times we hear the term 'excessive' competition. But there is no such thing as excessive competition insofar as suppliers compete by supplying differentiated products. 'Destructive' competition is possible, but only when products being sold are the same in all attributes and the suppliers compete by cutting prices. Consumers expect more choice and they are willing to pay higher prices for high-quality products. A competitive market makes it easier to provide more diverse and innovative products. TPA or open-access to storage facilities are essential to a competitive natural gas market. It is also conceivable that non-national third-party marketers can supply natural gas to any economy.

[37] Hasegawa [2002].

CHAPTER 7

CONCLUSIONS

While the traditional utility functions of gas storage have been those of system operation such as supply-demand matching and system balancing, new functions for direct profit seeking, the so-called commercial functions, are developing. The commercial functions of gas storage are at the centre of the discussions about gas market reforms, including the balancing market where market participants trade gas commodity and capacities of transport and storage as balancing services. Although more commercialisation of gas trading arrangements is believed to enhance the efficiency of the market, the degree of commercialisation differs across economies. On these grounds, the study attempts to investigate the development of commercial structure in the natural gas storage industry in the context of energy market reforms and to derive policy implications for the natural gas industry in the APEC region.

There is no single model (either in theory or in practice) that can apply to every economy. We could not run a simulation of gas systems, since it is too big a task in terms of resource requirements and data collection. Instead, we chose to survey and derive implications from existing literature and practices. The study also evaluates industry practices from selected economies relative to (both positive and normative) established theoretical results.

Treated as part of the transport system, gas storage itself has not been such a significant subject in the theory of peak-load pricing. However, an overview of the literature suggests a few important points for our purpose. First, by having storage facilities, fewer plants (fewer pipelines in our case) will in general be used and peak prices will be lower than otherwise, and considerable welfare benefits can be obtained. Secondly, in a gas industry with shippers' access to storage and with an established financial market for gas trading, less volatility in prices and in consumption tends to result. Thirdly, disregard for the different elements of outage/shortage costs can lead to problems, for example in under-investment in storage capacity.

We have looked at some selected economies in the APEC region, especially those that have LNG storage facilities including LNG receiving terminals. Deregulation of retail gas markets and customer choice programmes in the US have an impact on the rate at which natural gas storage use becomes more commercialised. The programmes shift some or all of the responsibility for gas supply from the local utility to marketers, sometimes including an unregulated affiliate of the local utility. As the responsibility for supply is shifted, so is the use and control of the assets needed to deliver that supply, including pipeline transport and storage. As a representative case of the bilateral model where the market is operated on the basis of decentralised bilateral contracts between market participants in every aspect of trading, the US natural gas market has developed a Pareto-improving tool to allow for at least the partial commercialisation of storage assets, the Agency Agreements. It is a good case for rent sharing between market players and enhanced efficiency resulting from higher utilisation of storage facilities in a liberalised market setting.

The history of the Korean gas industry shows that under-investment in gas supply facilities occurs unless the shortage costs of consumers are appropriately taken into account. Japan is considering introducing third-party access to LNG receiving terminals. It seems that the most important issue is how to distribute rents attached to terminal facilities that have been imputed to the existing utilities that import LNG through their own LNG receiving terminals. Another development in the LNG business in Northeast Asia is that Chinese Petroleum Corporation of Chinese Taipei diverted nine cargoes to Korea and Japan in the winter season of 2000-01. This raises a question about the possibility of more commercially oriented LNG trade in the region, including the import-export of LNG storage capacity.

Although it is not an APEC economy, the UK experience offers a good model of market-based trading arrangements for gas and capacity. As a representative case of the poolco model where a central system/market operator operates the pool of market participants, the UK system relies mainly on the gas supply network of Transco, the largest Public Gas Transporter in the country. Gas storage and other balancing services are traded through Transco (as system operator) network and within-day gas commodity is traded through the On-the-Day Commodity Market in which Transco is only one of the gas traders. The UK's system balancing is required to be consistent with the gas trading arrangements which are to support effective competition between gas shippers. There seems to exist a certain merit order of plant dispatch by Transco depending on cost characteristics and market and system conditions. That is, it is possible that the dispatch order changes as the cost characteristics change. For instance, higher price signals for interruptible loads may prohibit Transco or shippers from calling interruption as frequently as before and induce Transco to invest more in transport and storage facilities.

We may summarise the messages that can be delivered from the discussions in this report as follows. First, gas storage facilities allow a gas system to function with less transport capacity and to moderate peak prices, leading to consumer benefits. Also, in a gas industry with shippers' access to storage and with an established financial market for gas trading, there will be less volatility in prices. Secondly, disregard for the different elements of outage/shortage costs can lead to problems, for example, underinvestment in storage capacity. Related to this issue is that while large-volume and high load-factor consumers are desired to be potential interruptible loads for system security, the interruption costs incurred by them must be reflected appropriately in the tariff structure. Third, whether a gas market is based on a bilateral model or poolco model, more liberalisation of the market seems to facilitate the development of a commercial structure of the gas storage industry. Fourth, a commercial business structure implies competition for balancing services between system operators and system users, and competition among diverse balancing tools. Thus, the policy-maker needs to ensure that the market strikes a balance between costs for system operators and those for system users and that diverse system balancing tools compete according to their cost characteristics. These cost characteristics of the tools are best realised in a market where gas and capacities are traded on a commercial basis.

There are still many issues to be addressed concerning the role of government as the rule setter. The development of a commercial business structure in the natural gas storage industry as well as in all other industries is constrained by legally allowed trading arrangements. Too low a threshold for a system operator to call interruption is likely to result in under-investment in capacity on the system operator's side from a social point of view, and vice versa. There are always trade-offs between efficiencies in a market and other policy objectives, the equity objective in particular, that government attempts to achieve through and within the market in question.

Market participants respond to government policies sometimes by simply following the rules set by government and in others by taking part in the process of policy formulation in pursuit of rents attached to their business. Having more information in terms of both quantity and accuracy than government, they are in a better position than government to make the outcome favourable to themselves, which may or may not be desirable for society. Security issues may be addressed better by government than by private participants, but security is bought only at certain costs to society and has implications for income distribution both within and across generations. All in all, while activities of private participants change rent distribution, government policies also greatly affect rent distribution, which effectively is at the core of all deregulatory policies in many economies. And, as long as governments set good rules, market participants have found ways to make the market more efficient and keep it at least as equitable as before.

As presented previously, theory tells us that we should adopt more attributes of peak-load pricing in the industry, whether it is operated by a public entity or by private participants. In fact, practices in some economies indicate that adopting peak-load pricing will lead to reduced storage requirements, that existing storage capacities are utilised more efficiently, and that market participants are finding new ways of sharing rents in storage capacities.

However, in addition to the discussion of rent dissipation at a fundamental level, there are specific issues that await further study. One is concerned with possible changes in the role of LNG storage in the context of regional interconnection of gas pipelines in Northeast Asia. Topics that ought to be studied include: border price of pipeline natural gas, changing inventory turnovers of LNG tanks and cost implications, and resulting load coverage between LNG and pipeline natural gas. As regional energy market integration is being discussed, trading of storage capacity across economies in broader terms, including LNG ship swapping and LNG traders' participation, may well have a large impact on the trading arrangements for LNG in the region.

Until now, it has been assumed that with storage included, peak-load pricing discussion is not so interesting since storage has been regarded only as part of gas transport. But storage service may be treated in the framework of peak-load pricing, as the gas storage business is now recognised as an independent industry. For example, given the coexistence of market and traditional utilities to match supply and demand for gas and capacities, shippers or system users and a system operator may be regarded as competing for balancing tools. As another example, if an interruptible customer is considered to supply a balancing service to a system operator and if the system operator buys the service, the role of storage in gas supply may be analysed from a different perspective. In other words, use and expansion of the gas supply system in a liberalised market may be modelled in terms of a competitive market, where both traditional utilities and system users are both consumers and suppliers of gas and capacities. It will involve a different look at the same old issue and new preference structures for the system operator and the traditional consumer, including their risk aversion, but is likely to supply new insights to the storage and peak-load pricing discussion.

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