

## 1. General Overview - Background Data

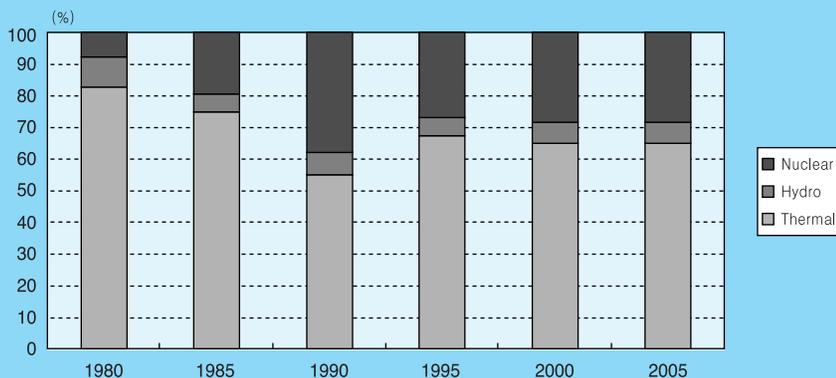
Korea uses a combination of thermal, nuclear, and hydroelectric capacity to meet its demand for electric power. Total power generation capacity was about 66,667 MWs at the end of 2005, according to figures published by the Korean Electric Power Corporation (KEPCO). Nuclear power increased its share in installed capacity from about 7 percent in 1980 to almost 40 percent

# Electricity and Natural Gas Sectors in Korea : Synthetical Overview and Recent Developments\*

in 1990; at the end of 2005, this share stood at about 28 percent (see chart below). The start of LNG imports in 1986 and the increased use of natural gas in power generation resulted in an increase of thermal capacity. Currently, LNG-fired capacity accounts for about 26 percent of total installed capacity

Figure 1.

Installed Capacity by Fuel

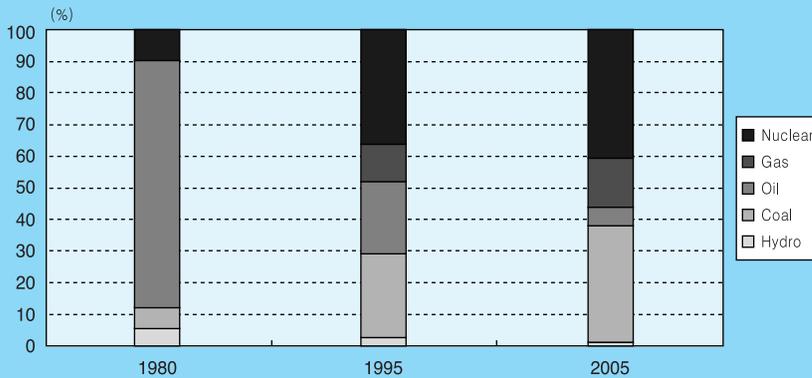


Source : KEPCO.

\* Modified version of the draft of 'Commercial Frameworks for Gas-Power Value Chain Development: Korea Updated', Cho, Chang Hyeun, Gurcan Gulen, and Michelle Michot Foss, Center for Energy Economics, University of Texas at Austin.

Figure 2.

Generation by Fuel



Source : KEPCO.

and coal has a share of about 29 percent - both similar to nuclear capacity. Oil accounts for about 10 percent of total installed capacity with the remainder based on hydro.

However, when one looks at the use of this installed capacity for generation, nuclear and coal account for 77 percent of all electricity generated in 2005. The following chart also shows the striking change in Korea's use of fuels in power generation: almost 80 percent of electricity was generated by combusting heavy oil and gas played no role in 1980. Today, natural gas is used to generate about 16 percent of electricity, while oil has a share of only about 6 percent in electricity generation. Obviously, most gas-fired capacity is kept for peaking purposes or as reserve margin.

Over this period of change in Korea's fuel portfolio, electricity prices have shown various trends. The rate decreased during 1980s, increased during 1990s~beginning of 2000s, and largely stationary since then. The residential rate decreased from 69.87 won/kWh in 1982 to 52.94 won/kWh in 1990, rebounded to 96.41 won/kWh in 1999 and declined to 91.07 won/kWh in 2005. Similarly, the industrial rate decreased from 58.61 won/kWh in 1982 to 43.84 won/kWh in 1991, rebounded to 61.56 won/kWh in 2001 and declined to 60.25 won/kWh in 2005. The trends partly reflect increased ratio of nuclear with decreased ratio of oil (contributed to lowering generation costs) in fuel

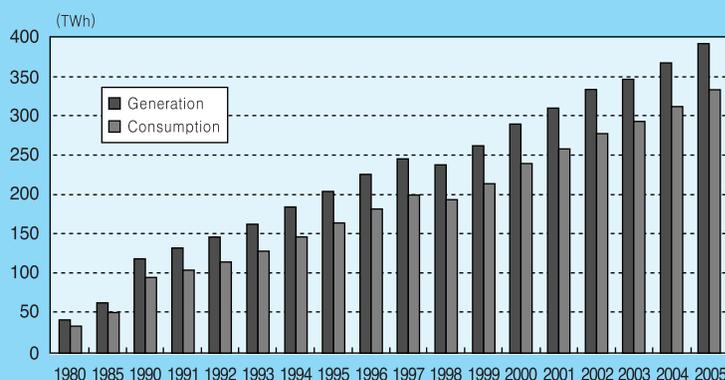
portfolio during 1980s, and redeclined ratio of nuclear with increased ratio of gas (contributed to raising generation costs) since then. The consistently retained price gap between industrial rate and residential rate reflects the policy consideration of the general price stabilization, international competitiveness and energy savings as well as trading volume.

Korea has ratified the Kyoto Protocol on greenhouse gas emissions. While its status is “non-Annex I state”, meaning it has not undertaken to meet specific targets, its future plans emphasize the development of more nuclear power plants to reduce growth in carbon emissions. A dozen additional nuclear plants are planned before 2015 when the nuclear capacity is expected to account for about 37 percent of total installed capacity, a substantial rise from about 28 percent in 2005.

In September 1998, KEPCO officially dedicated its Ulchin Number 3 nuclear reactor and launched the construction of Ulchin Nuclear Power Plants Numbers 5 and 6. Ulchin Number 3 has a generating capacity of 1,000 MWs and is the first nuclear power plant built completely with Korean technology from design to construction. The Number 4 Ulchin nuclear plant was completed in late 1999, Number 5 was completed in mid-2004, and Number 6 completed in mid-2005.

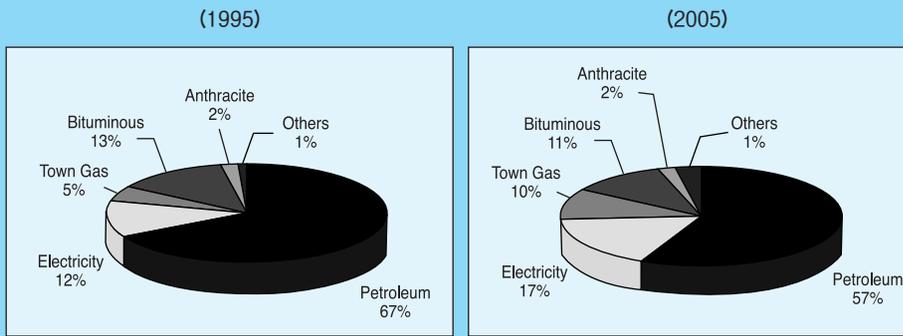
The Korean government estimates that electricity demand will increase on

**Figure 3. Electricity Generation and Consumption**



Source : Energy Economic Institute.

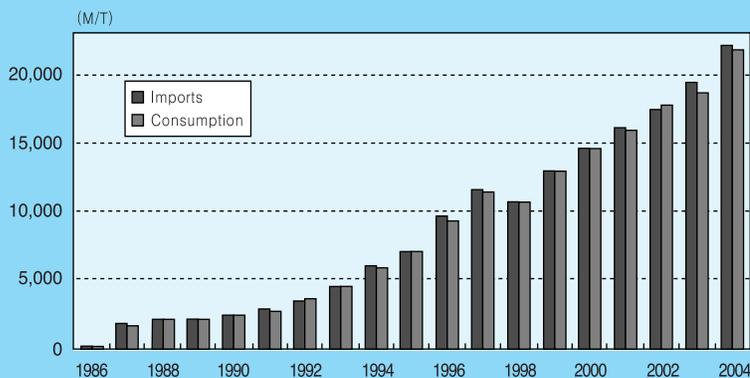
**Figure 4. Final Energy Consumption**



average by 3.3 percent per year from 2001 through 2015. The following chart shows the historical trends of electricity generation and consumption. Both generation and consumption of electricity shows continuously increasing trends throughout the 1980s, 1990s and up until the present time when the demand has increased from 32.7 TWh in 1980 to 332.4 TWh in 2005 at an average annual rate of 10.9 percent despite the slowdown in 1998.

Electricity has a share of 11.5 percent of Korea's final energy consumption in 1995, but its share has increased to 16.7 percent in 2005. In 1990, total electricity sales in Korea recorded 94,383 million kWh in sales, which has risen

**Figure 5. Imports and Consumption of Gas**



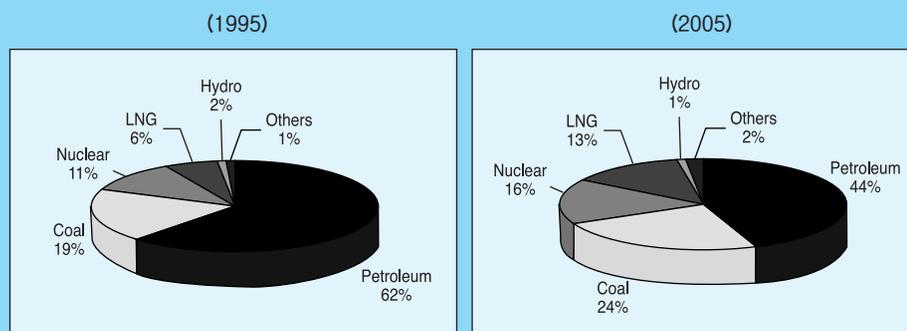
Source : Energy Economic Institute.

to 332,413 million kWh in 2005.

There is little production of natural gas in Korea. The country started importing LNG and consuming natural gas in 1986, after the founding of the state-owned monopoly LNG importer Korea Gas Corporation (KOGAS). Korea currently relies on imported LNG for most of its natural gas demand, while it began producing for the first time a small quantity of natural gas from one offshore field in early 2004. Although LNG had a share of only 3.2 percent and 6.1 percent of Korea's primary energy consumption in 1990 and 1995, its share has steadily risen until recently, reaching 13.3 percent in 2005. By 2010, the share of LNG in total energy consumption is expected to reach 14.8 percent. With the demand surging, natural gas consumption in all sectors including electricity generation is expected to rise in the mid term. Corresponding to the high demand growth, KOGAS has continued with its efforts to expand the national pipeline network. The length of the national pipeline network is 2,511 km as of the end of September 2006.

Currently, the country is the second largest importer of LNG worldwide with 22,153 million tons or 1,049 bcf of LNG imports in 2004. LNG imports increased by almost 400 percent between 1990 and 1997, fell by 6 percent in 1998 due to the impact of Asian Crisis on Korea's economy. In 1999, Korean economy recovered and new supplies from Qatar came on stream and imports bounced back by 21 percent. Since then, LNG imports continue to

Figure 6. Primary Energy Consumption



show a pattern of rapid growth. Imports of LNG grew by nearly 17 percent in 2004. Until 1994 Korean natural gas demand was higher in the electricity sector than in the residential/commercial and industrial sectors. Since 1995, however, the trend was reversed, where the residential/commercial and industrial sectors have had higher demand. Electricity sector consumes the natural gas about 2/3 as much as the rest of the economy as of the end of 2005.

In 2004, Korea began producing a small quantity of domestic natural gas from its one offshore field in 2004. Donghae-1 development project, operated by Korea National Oil Company (KNOC) is developing a natural gas deposit offshore from Ulchin in southeastern Korea. It is estimated that the deposit contains 240 bcf of reserves, which will satisfy only about 2 percent of the nation's natural gas demand. KOGAS is also joining various international gas pipeline development projects, one of which is the large-scale PNG undertaking in Irkutsk to connect pipelines from the Kovyntinkskye gas field in Northern Irkutsk to supply natural gas to China and Korea.

## **2. The Electricity Sector**

### **(1) Private Sector Participation**

Currently the electric utility restructuring in Korea is facing an uncertain future. The restructuring and privatization framework, the 'Basic Plan for Restructuring the Electricity Supply Industry' (hereafter, referred to as Basic Plan), finalized in January 1999, had been controversial, with unions fearing layoffs by new management and some politicians opposing foreign ownership. Although the legislation allowing the full privatization program to move forward is in effect, the deregulation process of the electricity industry in Korea was materially suspended in mid 2004, according to the decision by the Special Committee on Public Sector Structural Adjustment. The Committee was composed of 12 members, 1 neutral chairperson, 2 from labor, 2 from employers, 3 from the Government, and 4 from academies. The Committee

decision was based on the final report of the Joint Research Team on the disputed points and relevant foreign cases of the electric utility restructuring. 7 members including both the scholars supporting labor union standpoint and pro-restructuring scholars constituted the Team.

Initially, the restructuring was implemented in accordance with the Basic Plan, containing the phased plan to unbundle the state monopoly KEPCO into generation, transmission and distribution units. Generation sector of KEPCO was split up into six structurally separate generation companies (Gencos) in April 2001. Five of these Gencos operate thermal and hydroelectric facilities, and were of roughly equal size in terms of installed generating capacity - between 7,000 and 8,000 MWs. The sixth was comprised of all of KEPCO's nuclear plants, which were kept together in one corporation under government ownership. The government moved ahead with plans for privatization of the Gencos except the sixth. In April 2002, the Basic Plan for Privatization of Gencos was announced. Since then, several attempts have been made for trade sale or listing of 30 percent equity of the South East Power Company, designated as a starter generation company for privatization. However, the attempts were abortive. Until the present time, all companies remain public and subsidiaries of KEPCO. Privatization of distribution sector has not been attempted due to the suspension of the deregulation process in 2004.

Most of Korea's generating capacity is controlled by KEPCO. Yet, a few private independent power producers (IPPs) exist. GS Power, owned by the GS Group conglomerate, which was spun off from LG Group conglomerate, operates a 540-MW independent power plant at Bugok near Asan Bay. The plant is natural gas-fired and is expanding capacity. GS Power purchased the existing Anyang and Puchon plants in June 2000, with a combined capacity of 950 MW, from KEPCO after a competitive tender. One of the first firms to take advantage of the opening to foreign investment was PowerGen of Britain, which acquired a 49.9 percent stake in GS Power. But it lost its stake in the company in 2000. Tractebel is investing in a new 519-MW IPP plant in Yulchon in partnership with Hyundai. In another significant development,

Korea's original IPP, Hanwha Energy was spun off from its chaebol parent company in June 2000, in a deal in which El Paso Energy acquired a 50 percent stake. Hanwha Energy operates a 1,800-MW plant at Incheon. IPP project activity has been greatly slowed down by the uncertainty over the privatization of KEPCO, and no new major IPP projects have been announced since the beginning of 2005.

## (2) Regulatory Structure

The Act on Promotion of Restructuring of the Electric Power Industry, enacted on December 2000 enabled the division of the power generation sector of KEPCO into several companies. Even before this legislation, KEPCO has been reforming itself along with the government policy of reducing the role of the public sector in the economy that was enforced after the financial crisis in 1997. The company successfully sold two thermal co-generation plants as well as its shares in five companies (mostly telecommunications businesses) to raise about \$526 million. KEPCO also facilitated the participation of local firms in the auction of Powercom, another telecommunications firm spun off from KEPCO.

The Korea Power Exchange (KPX, power exchange) and the Korea Electricity Commission (KEC, regulatory agency) were established in April 2001 in preparation for eventual restructuring. The Electricity Business Act, amended in February 2002, legally mandated their establishments. Currently, KEC is under the supervision of the Ministry of Commerce, Industry and Energy (MOCIE). MOCIE envisages that it will become an independent regulatory agency in the future. In the Electricity Business Act, KEC is referred to as a regulatory body for competitive power market. The industry is largely regulated by KEC at present.

## (3) Market Characteristics

Initially, Korea's electricity market was expected to be created according to the

following timetable:

Phase 1 - Preparation (December 1998 - December 1999) including legislation, valuation and separation of KEPCO's assets, formation of generation subsidiaries and development of a wholesale power pool

Phase 2 - Competition in generation (October 1999 - December 2002)

- Privatization or divestment of KEPCO's generation subsidiaries
- Competition between these new generation companies in a wholesale power pool (one-way bidding)
- Formation of new distribution companies
- Commencement of privatization of distribution companies and introduction of two-way bidding

Phase 3 - Wholesale Competition (2003 - 2009). Preparation for retail competition. During this period, appropriate metering and communications facilities and trading systems will be put in place.

Phase 4 - Retail Competition (After 2009). Initially, large consumers will be eligible to purchase from competing suppliers (Currently, the industrial users consume about 56 percent, the commercial customers consume about 29 percent and the residential users account for the rest of electricity consumption). MOCIE expects to see the emergence of traders, brokers and aggregators competing to supply eligible consumers. The franchise boundary will then be lowered in stages.

The above time table is no longer valid due to the suspension of the deregulation process of the industry. Even in the suspension, however, where the introduction of two-way bidding was frustrated, a kind of quasi-competitive, one-way bidding wholesale market called Cost-based Pool (CBP) is being operated by the Korea Power Exchange (KPX). Under the current CBP system, market price is composed of the marginal price and capacity payment (CP). There are two kinds of marginal price: BLMP (Base Load Marginal Price) and SMP (System Marginal Price). BLMP is applied to base load generating units such as coal and nuclear energy; SMP is applied to non-base load units. Capacity payment is the price paid to a generating unit that has declared its availability during the day.

The SMP refers to the cost of the most expensive generating unit included in the Price Setting Schedule (PSS). PSS is set up by a computer program that can minimize the total production cost of generating units including the startup cost and incremental fuel cost. During some hours, certain generating units are not entitled to set the market price owing to their technical characteristics such as ramping rates, minimum output level, etc. The BLMP is determined as the most expensive base-load generating unit in the PSS. Similarly, the SMP is determined based on the cost of the most expensive generating unit in the non-base load market.

KPX forecasts the demand for the trading day and receives offers for available capacity from generation companies one day ahead. It then determines the market price by producing a PSS. In the PSS, the SMP values for each trading hour are calculated to meet the demand for each hour. Congestion or generation constraints such as fuel limitation and district heat supply are not considered in this procedure.

If the wholesale market was introduced, market prices and trading volume would have been determined based on the price bidding without having to classify costs into fixed and variable costs. Currently, however, both fixed (capacity payment) and variable costs for each generating unit are examined monthly by the Generation Cost Assessment Committee (GCAC) based on the documents submitted by the generators. The Committee is composed of 6 to 9 members from KEC, KPX, Gencos, KEPCO, and other electricity specialists. The necessity of the Committee may be justified by its role of setting prices to (nonexistent) potential wholesale market prices as close as possible based on the cost data.

Electricity has a share of 11.5 percent of Korea's final energy consumption in 1995, but its share has increased to 16.7 percent in 2005. In 1990, total electricity sales in Korea recorded 94,383 million kWh in sales, which has risen to 332,413 million kWh in 2005.

The sources of Korea's electricity sales are classified into residential, industrial, and public/service sectors. In 2005, electricity sales to residential sector recorded 50,873 million kWh, where its sales to industrial sector were

166,813 million kWh and those to public/service sector were 114,727 million kWh. In 1980, the share of the residential sector, that of the industrial sector and that of the public/service sector in electricity sales was 16.4 percent and 70.0 percent, and 13.6 percent respectively. In 2005, those shares changed to 15.3 percent, 50.2 percent and 34.5 percent respectively, indicating a faster growth in consumption of the public/service sector compared to the residential and industrial sectors during 1980-2005.

#### (4) Electricity Prices

The electricity price in Korea is divided into six different categories according to consumer groups, and unit price for each group is different from one another. Moreover, the unit price of electricity is different from one another in accordance with time and season. Especially, the graduated price scheme is applied to the residential consumers. The main purposes of the scheme are to protect low income customers and control excessive consumption. The scheme comprises 6 different categories of sub-pricing systems. In the scheme, the price lower than production cost is applied to up to 200kW consumption, while much higher price is applied to more than 300kW consumption. The prices for general and industrial services vary not according to volume but according to season and time, with highest prices in summer day peak time. The prices for industrial, educational and agricultural consumers are lower

**Table 1. Electricity Prices by Sector(won/kWh), as of the end of 2005**

Tariff Categories	Applicability	Average Unit Price	Index
Residential Service	Residential Service	91.07	122
General Service	Public/Commercial	95.24	128
Educational Service	School, Library, Museum	89.00	120
Industrial Service	Mining, Manufacturing	60.25	81
Agricultural Service	Agriculture, Fishery	41.67	56
Street Lighting Service	Use of Lamp	65.65	88

Source : KEPCO.

Note : Index is based on 100 for the average unit price of all the tariff categories.

than those for other consumers. In the case of industrial service, lower prices are applied in consideration of the general price stabilization and international competitiveness purposes, though volume differences partly reflect the price differences from residential and general services. In the case of agricultural service, lower prices are applied to protect farmers and fishermen. Lower prices of educational service reflect the policy for encouraging education. As of the end of 2005, the unit prices for residential and public/commercial consumers are 91.07 won/kWh and 95.24 won/kWh respectively, whereas those for industrial and agricultural consumers are 60.25 won/kWh and 41.67 won/kWh respectively. The electricity price is also subject to a 10 percent VAT, in addition to the separate taxes and tariffs applicable to the fuel inputs (coal, oil and gas).

### **3. The Natural Gas Industry**

#### **(1) Private Sector Participation**

Korea relies on imported LNG to meet most of its demand for natural gas. Imports of LNG began in 1986, after the founding of the state-owned monopoly LNG importer KOGAS in 1983. Since then, imports of LNG from KOGAS have rapidly grown to meet the nation's ever increasing demand. As the nation's sole LNG provider, KOGAS imported 22.3 million tons of LNG in 2005, making KOGAS the world's largest LNG importing company and Korea the second largest importer of LNG worldwide. Korea currently gets most of its LNG from Qatar, Indonesia, Malaysia, and Oman, with smaller volumes from other countries including Brunei and Australia. Indonesia was the largest provider until 2000. Since 2001, however, Korea has imported the largest volume of LNG from Qatar. The supplies from Qatar began in August 1999 under a contract with Qatar's Ras Laffan LNG (RasGas) venture.

In addition to LNG imports, Korea began producing a small quantity of domestic natural gas from its one offshore field in 2004. Donghae-1 development project is developing a natural gas deposit offshore from Ulchin

in southeastern Korea. It is estimated that the deposit contains 240 bcf of reserves, which will satisfy only about 2 percent of the nation's natural gas demand.

The annual average growth rate of natural gas demand is forecast to be approximately 3.93 percent over the next 14 years (2004 to 2017). To meet his growing demand, KOGAS is expanding the existing LNG terminals (Pyongtaek, Incheon, Tongyeong) and pipeline network. KOGAS has recently increased its 140,000-kl storage tanks from 5 to 7 at the Tongyeong terminal, and added an extra 60.4 km of gas pipelines to the central part of the country. KOGAS has total capacity of 4.46 million kl (2.01 million ton) storage tanks in all three terminals as of the end of 2005. The storage capacity of KOGAS is scheduled to increase to 86.4 million kl (3.89 million ton) until 2017, with the rise in storage to demand ratio from 9.6 percent in 2005 to 12.7 percent in 2017. Also, Mitsubishi Corporation of Japan and Pohang Iron and Steel Corporation recently completed an additional terminal at Kwangyang, which is in the southern part of the country. Construction of the facility began in June 2002, and it started operation in June 2005.

In 1999, the government announced 'Basic Restructuring Plan for Natural Gas Industry' (hereafter referred to as Basic Restructuring Plan). According to the Basic Restructuring Plan, KOGAS was scheduled to be privatized until 2002. An initial public offering of 33 percent of KOGAS equity was carried out in December 1999. However, the planned moves to break KOGAS up into competing entities and fully privatize it were frustrated due to the failure of passage of the relevant legislation in the Korean National Assembly in 2002. The suspension of electricity industry restructuring in mid 2004 affected the advancement of natural gas industry restructuring adversely. Currently the natural gas industry restructuring and privatization of KOGAS are facing an uncertain future.

## (2) Regulatory Structure

The Minister of the Ministry of Commerce, Industry and Energy (MOCIE) has

the authority to approve changes in wholesale tariff, following consultation with the Ministry of Finance and Economy(MFE). Mayors or provincial governors have similar authority to adjust the tariff for the regional retail services. Tariffs are composed of two parts: the import cost of LNG (linked to the international price) and the cost of supply services.

The main purpose of the Basic Restructuring Plan was to remove any obstacles against competition and to restructure the natural gas industry with privatizing KOGAS. According to the Basic Restructuring Plan, KOGAS was to be split into two companies - one to deal with the facility operations and the other with LNG imports & wholesales. Furthermore, the latter company was to be divided into three independent entities based on Korea's long-term LNG purchasing agreements. Two entities were to be sold off to private investors, while one entity to remain under KOGAS' control until its sale. The LNG purchasing agreements were to be grouped in order to ensure a fair and transparent competition between the three companies for imports and wholesale. Open access system was to be adopted for all the terminals and the transmission network of KOGAS.

By the end of 2002, most of the government's stake in KOGAS was to be sold off, with the government holding a portion of the shares in consideration of the public nature of the company. Competition for the construction of distribution facilities was to be allowed in the beginning of 2000s. Any certified company was to be allowed to construct and operate the distribution facilities in the area where distribution service was not provided. The gas supply service by LNG tank lorry was to be introduced in the areas where distribution network was not provided.

At first, competition between two or three retail suppliers was to be promoted. Competition for retail services was to be introduced in phases after successful introduction of competition in the wholesale business. Large customers were to be allowed to choose suppliers. Then, the town-gas supply businesses were to be divided into operation of facilities and sales. Finally, retailers were to be allowed to market to small customers.

For overall supervision purpose of the natural gas industry, an independent

regulatory body was to be established and the current regulatory structure was to be redefined and reinforced to accommodate the plan.

Most of the schedules and the related time table in the Basic Restructuring Plan described above, however, are no longer valid due to the failure of passage of the relevant legislation in the Korean National Assembly in 2002 and the suspension of electricity industry restructuring in mid 2004.

### (3) Market Characteristics

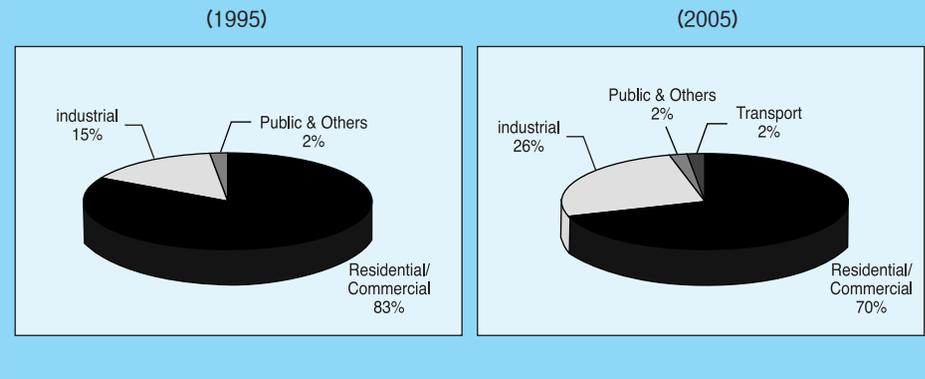
LNG had a share of only 3.2 percent of Korea's primary energy consumption in 1990, but its share has reached 13.3 percent in 2005. Major consumers of natural gas in Korea are town gas companies representing the demand in residential/commercial and industrial sectors and power plants representing the demand in electricity sector. KOGAS is the monopolistic seller in Korean wholesale natural gas market and the town gas companies have monopoly rights in their service territories of retail natural gas market. The majority of the town gas companies are supplied with natural gas from KOGAS.

In 2005, KOGAS recorded 22.8 million tons in sales, where sales to town gas companies were 14.0 million tons and those to power plants were 8.5 million tons. Until 1994 natural gas demand was higher in the electricity sector than in the residential/commercial and industrial sectors. Since 1995, however, the trend was reversed, mostly due to the relative price increase in oil and the rise in natural gas demand. The ratio of natural gas demand in the electricity sector and that in the residential/commercial and industrial sectors is about 63:100 as of the end of 2005.

In 2005, Korea recorded 17.8 million tons in sales of town gas, where its sales to residential/commercial sector were 12.5 million tons and those to industrial sector were 4.7 million tons. In 1995, the share of the residential/commercial sector and that of the industrial sector in town gas consumption was 82.3 percent and 15.4 percent respectively. In 2005, those shares changed to 70.2 percent and 26.1 percent respectively, indicating a faster growth in town gas consumption of the industrial sector compared to

Figure 7.

Town Gas Consumption



the residential/commercial sector during 1995~2005.

Currently, KOGAS imports majority quantity of LNG under the terms of the long-term contracts. Korea has diversified importing source of its LNG to Qatar, Indonesia, Malaysia, Oman, Brunei, Australia and Russia. Qatar has been the largest provider since 2001, though Indonesia was the one until 2000. Long-term contracts are mainly from Qatar, Oman and Yemen, which also provide equity participation in LNG projects. To manage the demand patterns of high seasonal fluctuations, where winter demands peak four times the summer minimum, KOGAS has negotiated for preferential imports in winter and minimal imports in summer, establishing annual delivery programs from existing long-term contract suppliers in the Middle East and Southeast Asia.

With the mid-term winter base contracts concluded in 2004 to procure 2 million tons of LNG from Malaysia and Australia, KOGAS has been able to mitigate a stable supply during the winter. Moreover, KOGAS established short-term contracts with Malaysia and Qatar to further secure a stable supply during the winter season.

Recently, long-term contracts with Yemen (YLNG), Russia (SEIC), and Malaysia (MLNG) were established to secure and maintain a stable supply in view of the expiring contract with Arun III in 2007 and to meet the demand forecast for LNG in accordance with the 7th Long Term Natural Gas Supply

and Demand Plan. YLNG, SEIC and MLNG are scheduled to start delivery by 2008, supplying 2 million tons, 1.5 million tons and 1.5 million tons respectively.

KOGAS is actively participating in international projects through equity participation in overseas LNG projects. KOGAS has purchased five percent equity in Oman LNG LLC, five percent equity in Qatar Ras Laffan LNG Co, and more recently, purchasing six percent equity in Yemen LNG (YLNG).

KOGAS established the International Projects Group in 2001 to expand its overseas business activities and to utilize and commercialize the technologies it has accumulated in the areas of construction and operation of gas facilities. The International Projects Group vigorously seek opportunities to provide consulting and training services and invest in overseas projects like LNG terminals or transmission construction. KOGAS is leading the PNG development project in Irkutsk, Russia along with CNPC (China) and RUSIA Petroleum (Russia). The PNG project in Irkutsk is a large-scale undertaking to connect pipelines from the Kovyntinskye gas field in Northern Irkutsk to supply natural gas to China and Korea.

KOGAS has also secured a foothold in the Southeast Asian gas market by establishing joint investments in the A-1 gas field exploration in Myanmar and undertaking a highly profitable gas and power generation consulting service project in Vietnam. Broadening its business scopes, KOGAS has established a presence in other regions, providing a training program for the Cawthorne Channel Associated Gas Gathering (CCAGG) project in Nigeria, thereby enhancing KOGAS' competency as an exporter of advanced technologies in gas facilities.

Furthermore, KOGAS participates in an integrated LNG combined system project; an integrated LNG combined system that generates power by integrating two different energy cycles to enhance production efficiency. The integrated LNG combined system uses a Brayton cycle, which is a gas turbine cycle at phase I. The system uses a Ranking cycle with vapor generated from the Heat Recovery Steam Generator (HRSG) at phase II. HRSG gathers energy from waste gas created by the gas turbine as it generates power. Currently,

energy efficiency of the integrated LNG combined system stands at approximately 50 percent and is expected to increase to around 60 percent in the near future.

In addition, Korea is exploring the possibility of a natural gas pipeline from the Kovykta natural gas deposit in the Irkutsk region of Eastern Siberia. The pipeline would supply China as well as Korea. The project as currently envisioned would supply about 1 bcf/d to Korea, and a larger volume to China. It now appears that the route should include a subsea section between China and Korea, bypassing North Korea. However, no final decision or binding contract has yet been concluded for the project.

#### (4) Gas Prices

Korea's natural gas industry consists of the wholesale market (KOGAS) that imports and distributes natural gas to the regional companies, and the retail (regional town gas companies) that supplies end-users. KOGAS also supplies end-users consuming more than 100,000 cubic meters per month, as well as KEPCO. The wholesale price charged to town gas companies, KEPCO and large end-users is subject to approval by the MOCIE. For power generation, the import price is adjusted on a monthly basis. The retail price of town gas to end-users varies according to the import gas price and prevailing exchange rates. Town gas prices are adjusted every quarter, but the range of adjustment must be within three percent of the previous price.

The price that is ultimately determined will reflect a number of factors,

**Table 2. Town Gas Prices by Sector** (won/cubic meter)

	Average	Residential	Industrial	Commercial
1990	224.9	284.9	200.5	214.4
1995	238.6	297.2	196.7	236.0
2000	389.3	461.3	291.8	406.0
2005	461.4	485.6	396.1	502.6

Source : Energy Economic Institute.

including:

- The purchase and offshore transportation costs for LNG, which make up around 75 percent of the final supply cost;
- Pipeline transportation, re-gasification, management and maintenance costs;
- Taxation, including VAT, import tariff on cif LNG import price, import surcharge on regasified gas, and a special excise tax on cif LNG price.

A number of levies and charges are included into the final price. For example, town gas companies are required to pay a safety management and import charge. Additionally, cross-subsidies exist between gas tariffs for power generation, town gas and regional retail prices. In terms of the regional retail prices, it is arguable whether regional cost differences can be incorporated into the price, suggesting that any regional pricing differences are either arbitrary, or reflect other social goals. Retail prices are also different from one another in terms of the customer class, which includes residential cooking, residential heating, commercial, general heating, general cooling, industrial, building cogeneration and regional cogeneration. The differences in tariffs reflect both the differences in costs and social equity purposes.

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