Energy Deregulation in Asia: Status, Trends, and Implications on the Environment

by

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Introduction

The World Bank surveyed energy reform in 115 developing countries in 1998 to see what steps have been taken and the achievements in this regard.[1] Included in this survey were nine countries from East Asia and the Pacific (EAP) and five countries in South Asia. The survey covered the power and oil and gas subsectors (divided into upstream oil and gas, downstream gas, downstream oil-refining, and downstream oil-wholesale and retail). The survey identified six key steps in the reform of each sector: corporatization, law permitting divestiture and unbundling, establishment of regulation, corporate restructuring, private concessions or greenfield investment, and privatization of existing assets. On average, according to the survey, two to three of these steps have been taken in the energy sectors in EAP and South Asia. The numbers for both sub-regions are slightly better than the developing world average, but lagged behind Latin America and the Carribean's, which have taken at least three of the six steps.

The results are mixed according to the energy sectors and by sub-region. In EAP, more steps have been taken in downstream oil-refining, followed by upstream oil and gas, than in any other sectors, including power. In South Asia, power, upstream oil and gas, and downstream gas equally lead all sectors in energy reform with half of the key reform steps having been carried out. In both sub-regions, downstream oil-wholesale and retail lags all other sectors in reform with only one or two of the reform steps having been carried out.

But there is one common trend in all the countries surveyed and in all sectors. Countries that have allowed private investments have very strongly tended to take other reform steps. The only exception is upstream oil and gas, in which the presence of a concession is associated with little likelihood of having taken other reform steps.

This paper reviews the status and direction of energy reform, or *deregulation*, in the Asian oil, gas, and power sectors. As implied, energy deregulation is defined in broad terms and encompasses privatization, the sale or transfer of government assets to the private sector, and restructuring, the move towards more competitive markets. Energy deregulation also implies transition from regulated or controlled to market-based energy prices. Asia covers selected countries in East Asia and the Pacific (Southeast and Northeast Asia) and South Asia and these sub-regions taken together.

Energy deregulation started in the hydrocarbon sector with the dismantling of government monopolies. This was in response to the 1970s oil price shock that made supporting government monopolies with subsidies and ignoring their financial performance unsustainable. Today energy deregulation is oriented towards increasing competition in different parts of the supply chain and choice in energy demand. The electricity sector leads in this direction.

Energy deregulation has implications on the economic, social, and environmental fronts – the three dimensions of sustainable development. This paper will look only at its possible impacts on

[1] Bacon (1999).

environment policies in the region. The next section provides an overview of the energy supply and demand and environment situation in Asia.

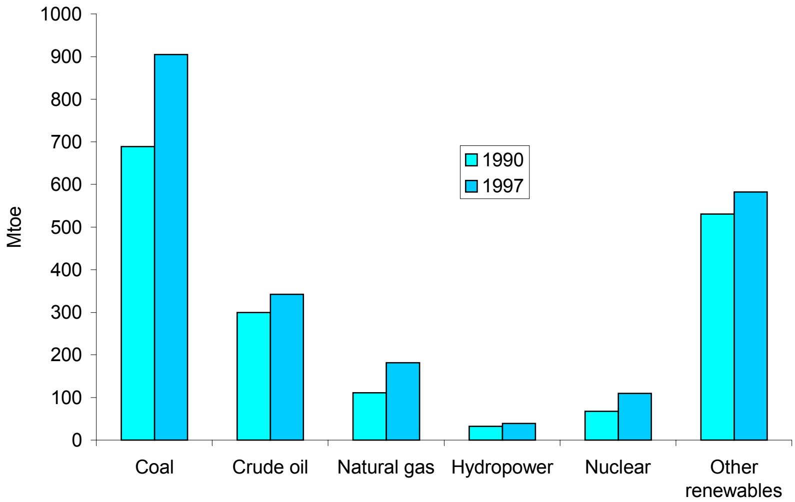
Overview of Energy-Environment Situation

Primary energy supply and demand

Largely because of India and China, Asia is endowed with coal resources that are equivalent to more than 20% of the world's recoverable reserves of coal. Recoverable coal reserves in China were placed at 126.251 billion short tons in 1999, while those of India were 82.379 billion short tons. In contrast, crude oil and natural gas reserves as of 1999 accounted for only around 4% and 6%, respectively, of the world's totals. Asia, however, represents 75% of the world LNG trade, with Indonesia, as the largest LNG supplier and Japan, the largest energy consumer, worldwide. In addition to fossil fuel reserves, the region also has substantial hydropower and renewable energy potential and harnesses nuclear energy in a few countries.

Total primary energy production reached 2,160 Mtoe in 1997 and represented more than one-fifth of the world's total. Of this, half was produced only in China. Coal accounted for 42% of the region's total energy production. Hydropower and other renewables contributed 29%, followed by crude oil (16%) and natural gas (8%). Nuclear energy added 5%.

Figure 1: Asian energy production by fuel, 1990 and 1997.

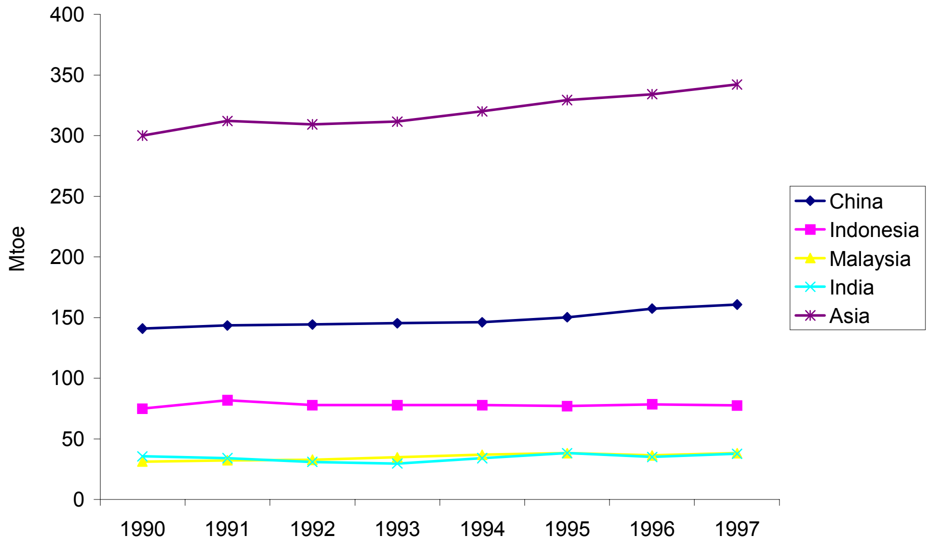


Source: IEA/OECD (1999).

Asia's coal production increased at the rate of 4% per year in 1990-1997. China's coal production in 1997 accounted for more than three-quarters of Asia's total and increased more or less at the same rate as the region in 1990-1997. Coal production increases during this period were very high in Indonesia, Malaysia, Thailand, and Vietnam, even though their combined coal production accounted for only a little over 5% of the region's total. India's coal production increased by 5% in the period, but accounted for more than 16% of the region's total.

On the other hand, Asia's crude oil production (including natural gas liquids) increased 2% per year in 1990-1997. China led the region in crude oil production with 47% share in 1997, followed by Indonesia (23%), Malaysia (11%), and India (11%). Vietnam and Thailand, however, registered the highest annual rate of growth in production at 20% and 11%, respectively, in 1990-1997.

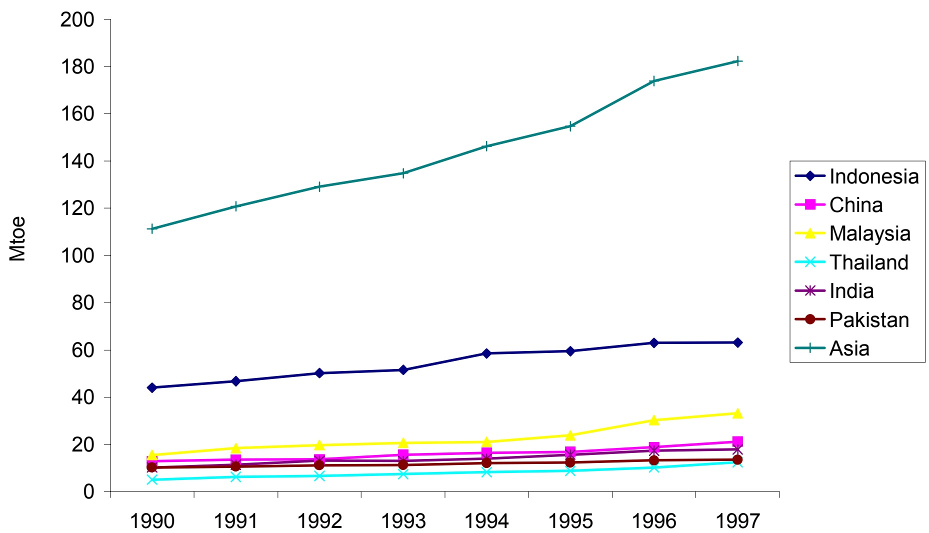
Figure 2: Crude oil production in selected Asian countries, 1990-1997.



Source: IEA/OECD (1999).

The highest rate of growth in fossil fuel production was registered by natural gas at 7.3% per year in 1990-1997. In fact, all Asian countries producing natural gas enjoyed healthy growth rates. The highest during this period was registered by Vietnam at 34%. The growth in natural gas production was also high in Thailand (14%), Malaysia (11%), India (8%), China (7%), and Bangladesh (7%). This was a result of a high domestic energy demand and in addition for Malaysia, the high demand for LNG in Japan, South Korea, and Taiwan. Indonesia has had the largest share, contributing 35% to Asia's total in 1997. Malaysia added 18%, China around 11%, and India close to 10%.

Figure 3: Natural gas production in selected Asian countries, 1990-1997.

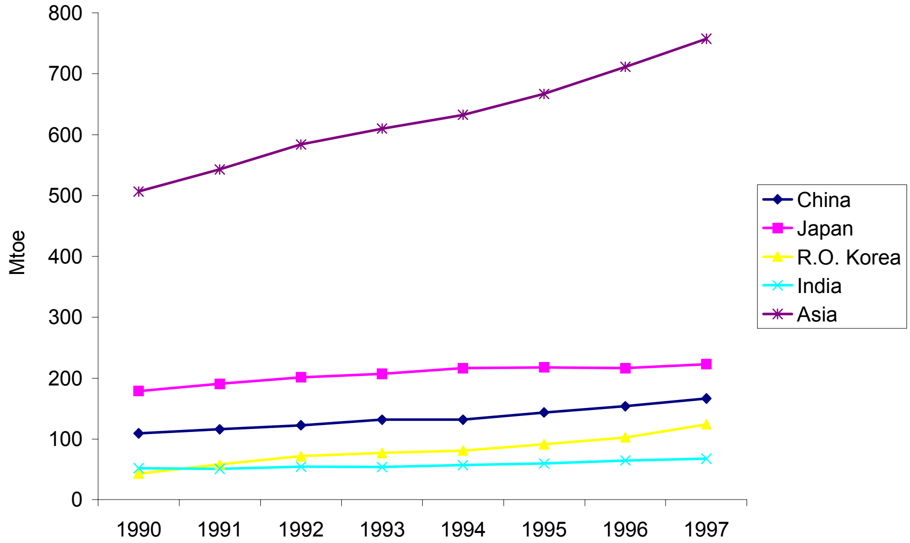


Source: IEA/OECD (1999).

The production of refined petroleum products also increased significantly at about 6% per year in 1990-1997. Two countries stand out in this case: Thailand and South Korea, with a 17% and 16%

increase per year, respectively. Brunei, Malaysia, and the Philippines also recorded growth rates higher than regional average. However, Japan, China, and South Korea remainED the biggest producers of petroleum products. Japan contributed 29% to Asia's total in 1997, China added 22%, and South Korea supplied 16%.

Figure 4: Petroleum products output in selected Asian countries, 1990-1997.



Source: IEA/OECD (1999).

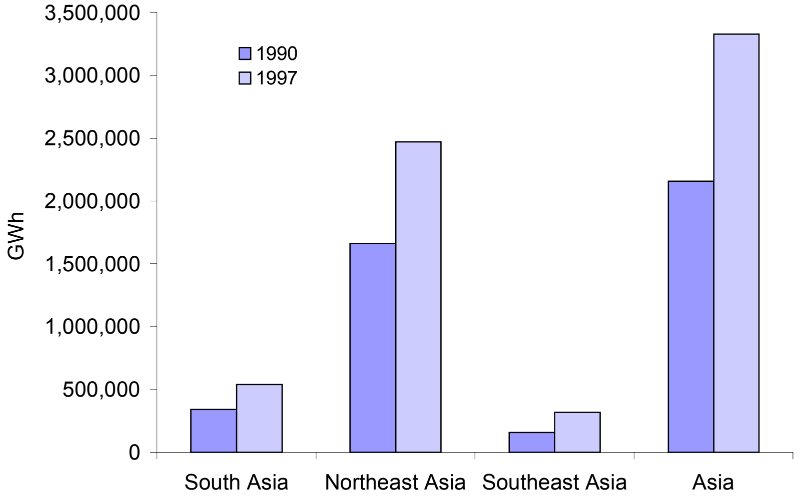
Asia also produces nuclear energy, equivalent to more than 17% of the world's total in 1997. Of this, Japan accounted for more than three-quarters, while South Korea added 18%. China' share was only less than 4%, but domestic nuclear energy production grew nine times between 1994 and 1997. India's share was also only less than 3%, but corresponding production grew more than 20% per year in 1994-1997.

Hydropower potential is large particularly in China, which accounted for more than 40% of Asia hydropower production in 1997. Japan also holds significant hydropower potential, contributing almost 20% to world's total hydropower production in 1997. Hydropower is also an important source of energy in India, whose hydropower production in 1997 was more than 16% of the world's total.

Hydropower represented only 6% of the total energy supplied by renewable energy sources to Asian energy mix. A huge portion, or 92%, came from combustible renewables (mainly biomass) and wastes. The balance was accounted for by geothermal, solar, wind, and other non-conventional energy sources. Geothermal energy, for example, has made important contributions in the energy mix of Japan, Indonesia, and the Philippines. Among the countries in Asia, Nepal and Myanmar depended on renewable energy for 80-90% of their total primary energy needs; Bangladesh, Sri Lanka, and Vietnam for more than 60%; and India, Pakistan, and Philippines for more than 40%.

Hydropower also contributed to total electricity generation in the region. The period 1990-1997, in particular, saw high rate of growth in electricity production in practically all countries in the region. Southeast Asia led with nearly 11% annual growth.

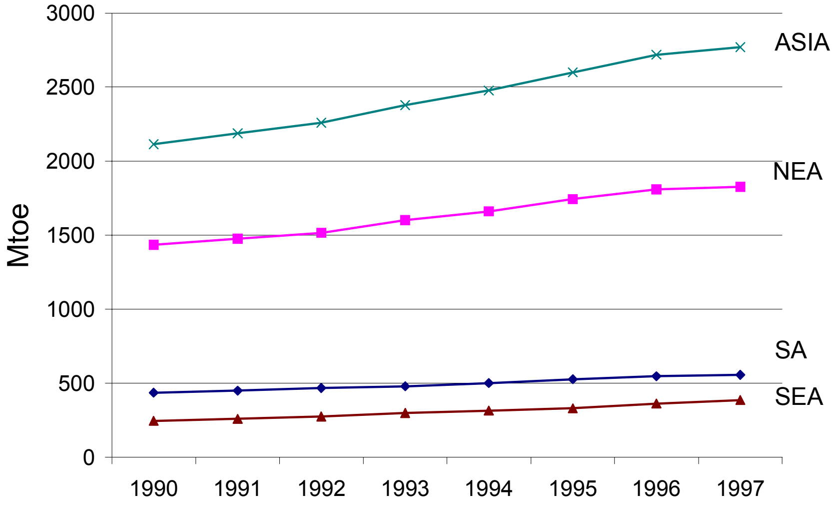
Figure 5: Growth in Asian electricity production, 1990 and 1997.



Source: IEA/OECD (1999).

Asia's total primary energy demand grew 3.9% per year in 1990-1997 to 2,771 million tonnes of oil equivalent (Mtoe). Of this amount, nearly two-thirds were by Northeast Asia. China alone accounted for 40% of Asia's total. Japan added more than 18%, which is slightly higher than India's 17%. The whole of South Asia represented 20% of Asia's total energy demand. Southeast Asia accounted for the remaining 14%. Energy demand in this region, however, was growing at more than 6% per year on average between 1990 and 1997, compared to less than 4% in South and Northeast Asia (with the exception of South Korea).

Figure 6: Growth in primary energy demand in Asian sub-regions, 1990-1997.



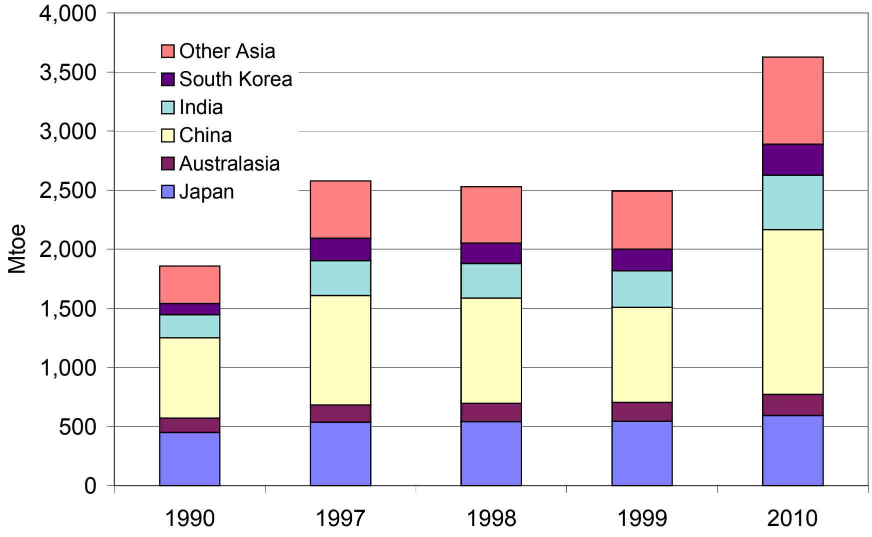
Source: IEA/OECD (1999).

The difference between demand and supply is met by imports. In 1997, net energy imports in Asia totaled 657 Mtoe, as against the world total of 21 Mtoe, indicating the strong dependence of the Asian economy on imported fuels. Northeast Asia, because of Japan and South Korea, is the most dependent on energy imports.

Primary energy demand forecast

Based on the latest forecasts by the Energy Information Administration (EIA) of the US Department of Energy, primary energy demand in Asia-Pacific[2] will increase from 2,493 Mtoe in 1999 to 3,629 Mtoe in 2010, or by 3.5% per annum.[3] At this rate of growth, Asia-Pacific's primary energy demand will have overtaken North America's by 2010, and its share in the global energy demand mix will have increased from 26% in 1999 to 29% in 2010. China's share in the region's total primary energy demand, which is the largest, will have increased to 38% by 2010 from 32% in 1999. China's energy demand growth of 5.1% per year during this 11-year period will also be the highest in Asia. India's energy demand will grow the second fastest in the same period (3.8% per year), but its share will remain under 14% even until 2020. The share of Japan in the region's total energy demand will decrease from 22% in 1999 to 16% in 2010, and its energy demand growth will be barely 1%. South Korea's share will remain at around 7% and growth will be just over 3%, less than the regional average. The rest of Asia will see their energy demand grow 3.8%, slightly above the regional average, but their share staying at around 20%.

Figure 7: Primary energy demand forecast in Asia, 1990-2010.

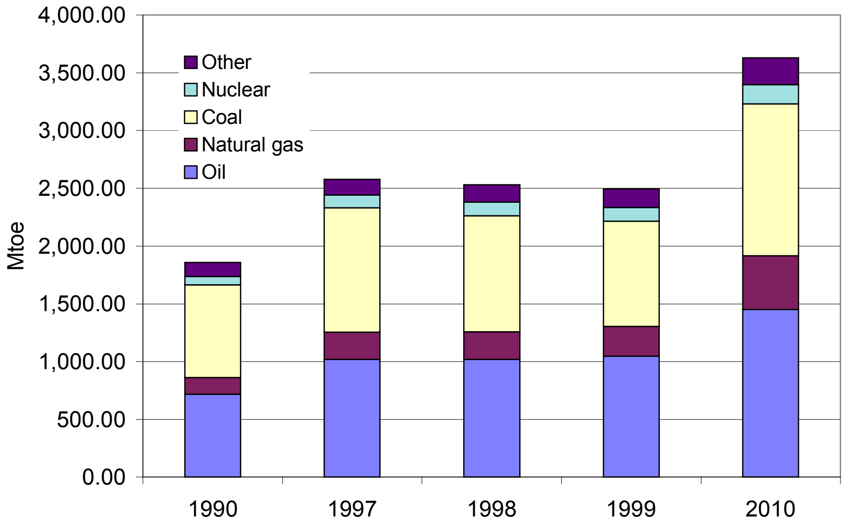


Source: EIA/USDOE (2001a).

Natural gas demand, growing at 5.5% annually in 1999-2010, will be the fastest, compared to oil's 3.0% and coal's 3.4%. Natural gas share to total energy demand, however, would remain less than 15% even until 2020. Oil and coal will continue to be the main fuels, with their shares through this period staying at 40% and 36%, respectively.

2 Including Australasia.
3 EIA/USDOE (2001a).

Figure 8: Primary energy demand forecast by fuels, 1990-2010.



Source: EIA/USDOE (2001a).

Private investments in energy infrastructures

Energy infrastructure development in particular for power generation, transmission and distribution, and oil and gas exploration and development, processing, transmission and distribution requires huge investment. For example in China, a total of US$36.74 billion was invested in power sector development during the 1990-1995 period.[4] It was estimated that this figure could have reached US$48.82 billion during the 1995-2000 period. Even with a relatively low GDP growth rate (i.e., 4.5% projected by APERC, 1998), the investment demand in the power sector is expected to reach US$69 billion at 1998 prices during the 2000-2005 period. In India, the government approved Rs79,589 Crore[5] (US$24.5 billion) for the power sector development during the 8th Five year plan, 1992-1997. During the 2000-2005 period, it was estimated that the power sector in India would need US$25 billion.

In Indonesia, before the financial crisis, capital outlays for power sector development was estimated to top US$60 billion during 1996-2008 period or US$5 billion per year on average. However, due to the financial crisis electricity demand was expected to grow slowly. Still, it was estimated that the country would need US$10 billion for its power sector development during the 2000-2005 period. Similarly it has been estimated that Malaysia would need a total of US$7.84 billion for the power sector development during the 2000-2005 period.

The power development plan of Thailand (PDP99-01) prepared by Electricity Generating Authority of Thailand would require 420 billion baht (US$10.5 billion) to implement through 2011. Based on EGAT's estimates, it is expected that the country will require about US$7 billion in the 2000-2005 period alone. Similarly, as estimated in the latest power development plan of Philippines, the country will need total investments of about US$3 billion for the power sector development during the 2000-2005 period (NPC, 1997).

In sum, it is estimated that by 2005 the annual investment requirement of the energy sector in East Asia alone would be in the range of US$150-200 billion.[6] Following global trends, two-thirds of that amount would go to the power sector.

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[4] CEERD (1999a).
[5] 1 Crore=10,000 Indian rupees.
[6] Based on Izaguirre (2000).

The role of private sector in financing the investment requirements for energy infrastructures has increased in the last few years. East Asia and the Pacific accounted for a third of the global investment in energy projects with private participation in 1990-1999, amounting to around US$60 billion (at 1998 prices)[7]. South Asia received private investments in energy infrastructures close to US$20 billion. Thus, the whole of Asia practically hosted US$80 billion worth of energy investments by private sector, matching that of Latin America and Caribbean, which have led the growth in private participation in energy. In contrast, however, to Latin America, in which private activity has been concentrated on divestitures or privatization of existing assets, private activity in Asia focused on green-field investments, specifically independent power projects selling electricity to vertically integrated state-owned utilities. IPPs accounted for 80% of private investments in East Asia and 93% in South Asia. Among the low-income countries, investments were concentrated mostly in China and India. Among the middle income countries in the region, Indonesia, Malaysia, and Thailand have always figured among the top in the list.

The financial crisis, however, has dampened private investments in the region. Private activity in East Asia dropped from US$12 billion in 1997 to US$3 billion in 1999 as a result of cancellation of many high-profile projects in Southeast Asia and reduced activity in China.[8] In fact, annual private energy investments in Malaysia, the Philippines, and Thailand in 1998-99 were only one fourth than in 1993-97.

Energy and environment

Energy production, transformation, and consumption activities contribute to environmental degradation at the local, national, regional, and global levels. Countries like China and India, where coal accounts for around 70% and 60%, respectively, of the their total primary energy consumption, are the main sources of local and regional air pollutants. China tops in SO_2 and NOx emissions. APEC estimates these to be about 20 million tons and 7.4 million tons, respectively, in 1987.[9] India ranks second. The ALGAS study executed by ADB estimates India's SO_2 emissions to be 4.58 million tons and NOx emissions to be 3.08 million tons, both in 1990.[10] Also according to the ALGAS study, the energy sector accounts for 80% of the total 1990 greenhouse gases (GHGs) emissions of 11 Asian countries participating in the study.[11] These 11 countries represent 97% of the population, 95% of the land area, and 95% of the 1995 GDP of ADB's developing member countries. The same study projects that under a baseline scenario the energy sector will account for about 90% of the total GHGs emissions by 2020.

Energy deregulation in the hydrocarbon sector

Based on the World Bank survey cited earlier, in upstream oil and gas most of the eight countries surveyed (five in EAP and three in South Asia) have restructured their oil and gas companies and many have corporatized them or introduced laws permitting divestiture and unbundling. Half have allowed private concessions and three have established regulation. However, none of the countries surveyed in both sub-regions has proceeded with full privatization. Yet, the numbers indicate that major changes have taken place in the upstream oil and gas industry, and national oil and gas monopolies have been the focus of these changes. In China, the government created two vertically integrated oil and gas firms—China National Petroleum Corporation (CNPC) and China

[7] Izaguirre (2000).
[8] Izaguirre (2000).
[9] APEC (1997).
[10] ADB (1998b).
[11] ADB (1998a). These 11 countries include Bangladesh, People's Republic of China, India, Indonesia, South Korea, Mongolia, Myanmar, Pakistan, Philippines, Thailand, and Vietnam.

Petrochemical Corporation (Sinopec)—in an effort to restructure the industry. Before the restructuring, CNPC had been engaged mainly in oil and gas exploration and production onshore,[12] while Sinopec in refining and distribution. In 1998, the government ordered an asset swap that transferred E&P assets to Sinopec and refining and distribution assets to CNPC. CNPC now operates in northern and western part of China, and Sinopec in the south. A third entity, CNOOC, retains control over majority of offshore oil and gas production. The purpose of this restructuring is to prepare the industry as China enters the World Trade Organization (WTO), as well as to prepare these enterprises for international equity offerings.[13] Thus, in fact, all three firms have successfully launched initial public offerings (IPOs) in 2000 and 2001.[14]

In Indonesia, a new oil and gas law still pending in the legislature would privatize and unbundle Pertamina, the country's oil and gas monopoly, into separate entities handling exploration and production, transportation, distribution, and retail. In addition, Pertamina's function of awarding and supervising production sharing contracts with foreign oil and gas companies will be transferred to the Ministry of Mines and Energy. In Pakistan, the state-owned Oil and Gas Development Corporation (OGDC) has been corporatized and converted into a joint stock company. It is further planned that government-shareholding be disinvested through either a strategic sale, or through share offerings in the domestic and international capital markets. In Thailand, the Cabinet approved in 1997 the sale of government shares in Petroleum Authority of Thailand Exploration and Production (PTTEP) so that PTT's shares will be reduced to 51%. In Chinese Taipei, the Chinese Petroleum Corporation has been slated for privatization between 1998-2000.

Similarly, countries in the region have opened up oil and gas exploration and production to private and foreign investments. They enter into different contractual arrangements with developers to ensure a fair share of economic rents on their hydrocarbon resources.[15] Indonesia, Malaysia, India, China, and Vietnam develop their oil and gas resources through production sharing contracts. South Korea and Thailand use concessions, while Philippines employs service contracts. Brunei had used concessions before it decided to introduce other (non-concessionary) forms of agreements. It has adopted competitive bidding to invite foreign companies to develop its oil and gas resources.

In India, the foreign investment restriction has led to low reserve accretions. To attract private investment, the New Exploration and Licensing Policy (NELP) was announced in 1997. The government is now offering small and medium oil fields to the private sector, allowing companies to conduct their own seismic surveys and also encouraging joint ventures with Oil and Natural Gas Corporation (ONGC) and Oil India Ltd. (OIL) for exploration and production. Further, the Ministry of Petroleum has recommended that all exploration companies, including the ONGC and OIL, be given the right to market the extracted crude to any buyer, national or international, without reserving for the government the first option to purchase the entire output.[16]

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[12] Most Chinese oil production capacity, approximately 90%, is located onshore.

[13] EIA/USDOE (2001b).

[14] CNPC carried out its IPO for a minority share in a subsidiary, PetroChina, in Hong Kong and New York stock exchanges in April 2000 and raised over US$3 billion. Sinopec carried out its IPO in the same markets in October 2000 and raised about US$3.5 billion. Lastly, CNOOC held its IPO in February 2001, in which Shell bought a large block of shares valued at around US$200 million (EIA, 2001b).

[15] These are called petroleum fiscal systems that determine how the revenue from oil and gas production is shared between the government and the contractor involved in E&P. Concessions allow private ownership of mineral resources and contractor is subject to payment of royalties and taxes. In contractual systems, the government retains ownership of mineral resources and contractor receives a share of the production or revenue from the sale of oil and gas. In a production sharing contract, the contractor receives a share of production. In a service contract, the owner (government) receives a share of profit.

[16] The initial response to the first round of bidding in 1999 was disappointing with no bids from the major multinational oil companies. But India proceeded to award 25 blocks in January 2000. A second round of bidding with another 25 blocks on offer is underway (EIA, 2001c).

The privatization trend is also sweeping the downstream sector. Most of the countries surveyed by the World Bank have corporatized—usually the first step in the privatization process—their national oil and gas firms. Many have introduced a law allowing divestiture, particularly in gas, and a few have actually proceeded with partial or full privatization. In India, the government has reduced its equity interests in oil and gas transmission and distribution companies and to a greater extent in refineries. Other reforms taking place include deregulation of crude imports, permitting free import and export of oil products, granting refining companies rights to transportation links, permitting pipeline construction by independent refining companies, gradual removal of marketing dealer's commission and liberation of retail sales of products. On top of these, India is gradually phasing out the administered pricing mechanism and moving towards one that is market-based (see later section). Full deregulation of the downstream oil sector is expected by 2003. In Korea, Korea Gas Corporation (Kogas) is slated for full privatization by 2002. The Korean government held 50.2% stake in Kogas as of end-1998. In Malaysia, Petronas, the state-owned oil and gas corporation, sold 25% of its stake in Petronas Gas, which supplies gas to large consumers (such as power plants), in 1995. In Pakistan, the government plans to privatize Pakistan State Oil (PSO), which holds 75% of the market for petroleum products distribution and has 8,000 outlets. As part of this privatization, the government is setting up the Gas Regulatory Authority and the Petroleum Regulatory Board. In Thailand, PTT has been also slated for privatization, first by corporatizing its subsidiaries—PTT Gas, PTT Oil, and PTT International—and then by offering PTT's shares to the public.

Some have started to allow private investment in oil and gas transmission and distribution and oil refining and marketing. In Indonesia, Presidential Decree No. 31/1997 opened Indonesia's downstream sector to private investment, but Pertamina has remained as the sole distributor of refined products in the domestic market, even though private refineries has been allowed to sell their products to Pertamina or to intenational markets. The new oil and gas law still pending in the parliament would ultimately privatize Pertamina and Perum Gas Negara (PGN), which transmits and distributes natural gas. Pertamina would become a "normal" commercially focused company, while PGN would be broken into separate transmission and retail companies, and possibly an upstream company. Producers would be able to sell directly to consumers, transmission and retail distribution segments would be open to private sector companies, and there would be third party access (TPA) of pipelines. In India, the gas downstream industry remains in government hands. But it is committed to the eventual deregulation of the gas market, which would require a regulatory authority, a gas supply code and regulations for TPA use of pipelines. In Taiwan, the state-owned Chinese Petroleum Corporation (CPC) is the dominant player in all stages of the petroleum (oil and gas) industry, from exploration and production, transportation and distribution, oil refining and marketing, and LNG importation and processing. But significant competition began in July 2000 with the opening of a fourth private-owned refinery that when operated at full capacity would account for more than one-third of total refinery capacity in the country. A fifth refinery has been proposed by another private sector group but put on hold for environmental reasons. This same group has proposed to build Taiwan's second LNG import terminal.

In some countries, the downstream oil industry has been in private sector hands, but deregulation continues in other aspects of the industry. For example, in the Philippines, a new law deregulating the oil industry was signed in February 1998. The Downstream Oil Industry Act of 1998, or Republic Act 8479, liberalizes and increases competition in the downstream oil industry. For one, it imposes a single and uniform 3% tariff duty on imported crude oil and refined petroleum products. The act also encourages new entrants into the downstream sector by eliminating the requirement that all companies maintain a minimum 40-day inventory. Most important, under the new law, oil companies are allowed to set their own prices for refined products. In South Korea, the government under financial pressure decided in October 1998 to fully deregulate the oil refining industry. New companies have been allowed to enter the industry beginning 1 January 1999. Oil prices, except of LPG, have been completely deregulated since February 1998. The

Thailand downstream oil industry was deregulated in 1991 when oil price controls were lifted. Deregulation continues with liberalization of investment in domestic petroleum refining capacity, procedures for licensing for new service stations and promotion of competition at every stage of the LPG market.

Deregulation of oil and gas prices is discussed in a separate section.

Energy deregulation in the power sector

According to the World Bank survey earlier cited, seven of the nine countries surveyed in EAP and all of the five countries surveyed in South Asia have allowed the entry of independent power producers (IPPs). In 1996 and 1997, about half of the new IPP projects worldwide were in Asia and the Pacific. In 1997, Asia hosted 17% of the IPP projects worldwide.

Most Asian countries have introduced some degree of competition in generation by allowing IPPs to sell to established government utilities, most of which have attained the status of state-owned corporations. Many are in transition to privatizing their electric utilities and introducing competition in wholesale and retail electricity supply. These include Thailand, Philippines, Indonesia, South Korea, and Malaysia. In Thailand, despite delay in implementation due to the financial crisis, the government has contracted seven IPP projects with a total capacity of close to 6,000 MW, not to mention small private power producers, cross-border projects (with Lao, China, and Myanmar) and privatized generation subsidiaries of EGAT. The government has prepared the blueprint for introducing wholesale competition by 2003 or 2004, privatizing EGAT, and separating generation from transmission. In the Philippines, 33 IPP projects (excluding private rehabilitation and operation and maintenance projects) with a combined capacity of 5.2 GW were commissioned between 1991 and 1998. In 1999, IPPs accounted for almost 50% of total installed generating capacity. A law privatizing Napocor and allowing wholesale competition has been pending in Congress since 1994, but is being pushed by the present government. If approved the law will also break up Napocor into seven generation companies and a separate transmission company.

In Indonesia IPPs with a combined capacity of 6,500 MW have been completed, while projects totaling15,000 MW have been delayed or cancelled as a result of the financial crisis in 1997-1998. Nevertheless, the government is contemplating the introduction of a more competitive market in which different generators and off-takers would be competing in a pool. In August 1998, the government launched the Power Sector Restructuring Policy that will unbundle the Perusahaan Listrik Negara (PLN), the state power utility, and establish competitive electricity markets in Java and Bali. Part of the plan is to establish a ‘multi-buyer multi-seller’ market by 2003. Meanwhile, four IPP projects are in the pipeline in South Korea and due to come on-stream between 2001 and 2004. It plans to establish a power pool and a separate transmission company in 2002 and introduce retail competition in 2009. The Korean Electric Power Corporation (KEPCO) is also due for unbundling and privatization. Under the latest plan published by the Ministry of Commerce, Industry and Energy in January 1999, KEPCO would split its 42 thermal and hydropower plants into five subsidiary companies that will be sold through share issues and auctioning. A sixth that will comprise KEPCO’s nuclear plants will remain under the government. Malaysia opened its electricity market to IPPs in 1994, and 15 licenses were issued. As of 1998, nine of these with a combined capacity of 4.3 GW were in operation. Like most of its neighbors in Southeast Asia, Malaysia expects to introduce wholesale and retail competition in its electricity market. However, in contrast to its neighbors, the country has no definite plans or targets towards this end.

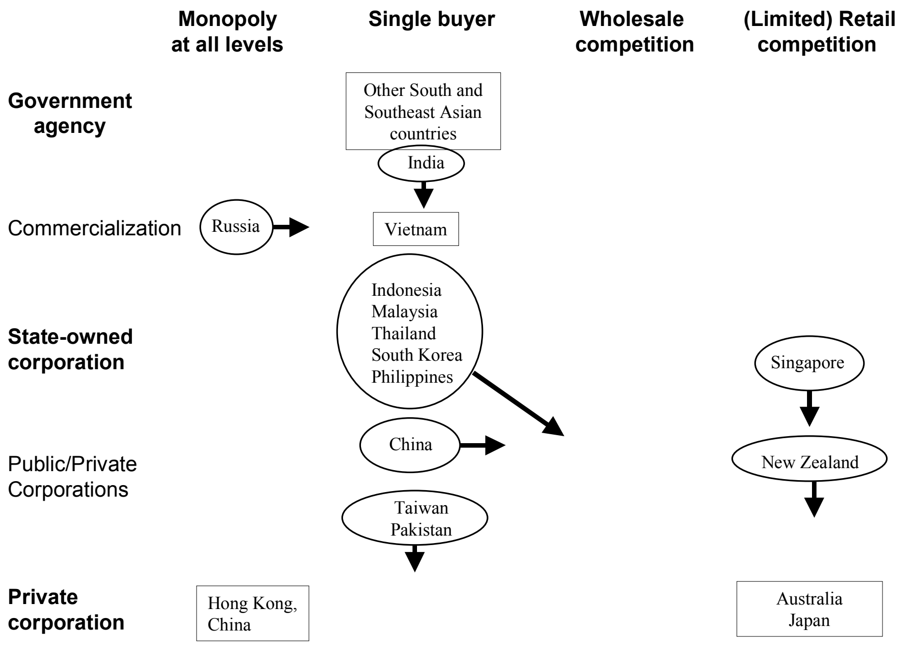
But some countries that have allowed IPPs do not follow the above trends; they include China, Vietnam, Taiwan, and Pakistan. In China in 1998 alone, 26 private power projects with combined capacity of 6.6 GW were in operation. On top of these, 14 projects (10 GW) were under construction or development and 61 (75 GW) were being planned or under consideration. IPPs now supply about 50% of China's power supply requirements. The State Power Corporation of China (SPC), which was established in 1997, has also announced that it intends to separate generation from its transmission and distribution businesses by 2005. A pilot bidding system has already started in five provinces and one municipality along China's progressive east-coast in 2000. The target is to establish a truly competitive electricity market by 2010 based on the experience gained through the pilot bidding systems. Yet, these plans do no include privatizing SPC. Similarly, Vietnam has recently instituted reforms that transformed its electric utilities into a vertically integrated state-owned corporation (Electricity of Vietnam, or EVN), but does not show indications of privatizing it nor introducing competition in the short- and medium-term. IPPs, however, is expected to add more than 2,000 MW to total generating capacity by 2005 and more beyond 2005. In Taiwan, the government approved in 1995 11 IPP projects totalling 10.3 GW. The first major IPP, however, was commissioned only in 1999 even when the government would allow IPPs to provide up to 20% of the country's electricity requirements. The amendment to the Electricity Act calling for the privatization of Taipower is pending in the parliament. The Ministry of Economic Affairs has set 2005 as the most likely date for privatization. However, there is no indication that wholesale and retail competition will be introduced in the foreseeable future. In Pakistan, a total of 33 IPP projects with combined capacity of 7,740 MW were approved between 1994 and 1995 by the Bhutto government.[17] The privatization of the Water and Power Development Authority (WAPDA) and Karachi Electricity Supply Corporation (KESC) is also underway. But as in Taiwan, there is no definite plan to introduce wholesale and retail competition.

On the other hand, the electricity sectors in the other transition economies in Southeast Asia as well as the other economies in South Asia remain in the hands of government departments or ministries with no independent accounting and management systems. For example, in India, the State Electricity Boards dominate the electricity sector. But reforms have begun in a number of states (Orissa, Haryana, Andra Pradesh, and Rajasthan) since 1994. In Orissa, for instance, the SEB has been split into two generation companies (one of which has been privatized) and one transmission company, independent from each other. The other states are following this lead.

Meanwhile, Singapore and Japan have introduced limited retail competition by allowing large electricity consumers to choose their power supplier. In Singapore, electricity customers with power requirements of at least 2 MW can choose their power supplier from July 2001 and can buy electricity in the wholesale market at spot prices at the end of 2001. Already, electricity customers with power requirements of at least 5 MW has been able to choose their supplier since April 1998. Six power retailers currently supply electricity directly to large customers. However, generation and transmission remain in the hands of state-owned corporations, although their privatization has been slated for the future. In Japan, an estimated 8,000 electricity consumers who use more than 2,000 kW annually at 20 kV or higher are able to choose their supplier from March 2000. Japan's electricity market is served by 10 privately-owned vertically-integrated utilities and IPPs that have been present since 1995.

[17] IPPs, however, have been involved in disputes with the government of Nawaz Sharif over the rates set in the power purchase agreements (PPAs). IPPs have been charged for allegedly engaging in price-fixing and bribing officials of previous government.

Figure 9 Status of privatization and deregulation of Asian electricity systems



Note: Classifications based on Hunt and Shuttleworth (1996).
Source: Based on CEERD (1999).

The entry of IPPs in generation has become almost a necessity in the transition of electricity sectors from being dominated by vertically-integrated government monopolies to one characterized by competition. The entry of IPPs paves the way for further reforms and contributes to increasing the competitiveness of the electricity sector.[18] This observation is consistent with that of the World Bank survey in which countries that allowed private investments tend to take other reform steps. Yet the role of IPPs is also changing with the introduction of competition at the wholesale and retail levels.[19] This trend will see a decrease in the traditional IPP contracts and the rise of merchant power plants.[20]

The setbacks of the Asian power sector due to the regional financial crisis in 1997-1998 exposed flaws in the IPP model and have stressed the need for more competitive arrangement than the single buyer model. It is true that the single buyer model has its benefits:[21]

- facilitates balancing of electricity supply and demand;
- less costly and not as institutionally demanding as wholesale competition (it preserves the role of state-owned enterprises (SOEs) and energy or power ministries and thus favors them), which allows third party access and multiple buyers and sellers;

[18] See for example Roseman and Malhotra (1996).

[19] Wholesale competition means that distribution utilities can choose generators, that is, they can continue to buy from generating utilities or directly from IPPs. Retail competition, on the other hand, allows final consumers to choose their electricity suppliers, with the large ones able to buy directly from generators.

[20] A pure merchant plant is a power plant built without guaranteed customers for the electricity generated by the plant (Smock, 1997). Developers bear the risk that they will be able to sell power to willing buyers. Hybrid merchant plants benefit from having at least some portion of their output secured under contractual sales arrangements. The merchant trend started in the United Kingdom with the introduction of wholesale electricity competition in 1990. It spread to Argentina, Chile, Australia, and other countries that adopted competitive bulk power supply systems. Now it is spreading to California, New England, Texas and other regions of the United States where competitive wholesale power generation is on the rise.

[21] Lovei (December 2000).

- simplifies price regulation by maintaining a unified wholesale electricity tariff;
- protects investors and creditors from market and regulatory risks (e.g. PPA); and
- a compromise to completely switching to wholesale or retail competition.

Yet, the disadvantages tend to outweigh the benefits:[22,23]

- encourages over-investment because investment decisions continue to be made by government officials (through power development plans, IPP approval process, based on government load forecast) who do not have to bear the financial consequences of their actions (government and taxpayers do);
- creates contingent liability for the government (through the prescribed government guarantees) when state power utilities default in their contractual obligations with IPPs;
- prices rise, not fall, when demand collapse because of the take-or-pay provision (of the PPA);
- hampers cross-border electricity trade as state power utilities do not have strong commercial motive;
- weakens incentives of distributors to collect payments from customers as state-owned single buyer normally could not take unpopular action against non-paying distributors;
- makes government intervention easy;
- no competitive pressure for the IPP to lower costs, so that efficient operation depends solely on the profit motive;
- dispatch can occur out of the merit order, leading to a loss of a system's productive efficiency;
- the lack of competition for market share between the IPP and other generators means that, even if operated efficiently, the IPP poses no threat to other generators: and
- delays transition to a truly competitive electricity market.

One flaw of the application of the IPP model in developing countries that was exposed during the financial crisis was in the allocation of risks. The PPA usually obliges the government to assume the foreign exchange risk. At first glance, it may appear that governments should assume the risks associated with currency exposures because they have some control over exchange rates (and interest rates), and, if they take on these risks, they will have incentive to follow stable macroeconomic policies. There are a number of reasons, however, why government should pass on to investors exchange and interest rates risks:[24]

- government guarantees may encourage investors to take large exposures to exchange and interest rate risks;
- exchange rate guarantees may have an adverse influence on government behavior, for example, they might discourage a government from allowing a needed depreciation of the domestic currency following a terms of trade shock;
- many governments—and the taxpayers who support them—are already exposed to the risks associated with exchange and interest rate shocks; and
- in the absence of a government guarantee, the private sector might have more incentive to manage exchange rate risk.

[22] Lovei (December 2000).
[23] Bacon (May 1995).
[24] Thobani (March 1999).

In general, moreover, government guarantees threaten to undermine the benefits of privatization or private sector financing of infrastructure in a number of ways:[25]

- if the government assumes the risk of project failure—for example, by guaranteeing demand for the services provided—private investors have little incentive to choose financially sound projects and to manage them efficiently;
- guarantees may impose excessive costs on the host country's taxpayers or consumers; and
- the issuance of guarantees could lead to a fiscal crisis by encouraging investors to take excessive risks.

Deregulation of energy prices

Energy deregulation also implies transition from regulated to market-based energy prices. However, this transition is more complicated and politically difficult as energy prices fulfil conflicting objectives of efficiency, social equity (affordability and accessibility to poor energy consumers), and financial viability of energy suppliers.

Thus, few countries in Asia have introduced market-based oil pricing mechanism (Japan, Philippines, South Korea, Taiwan, and Thailand). The Philippines and South Korea deregulated petroleum product prices in February 1998. In Thailand, petroleum product prices have been deregulated since 1991. In these countries, the oil refining industry is dominated by the private sector. In most other countries, oil producers are government owned and oil products prices are either controlled or subsidised or both. In China, Indonesia, Pakistan, and Vietnam, petroleum products prices remain regulated and controlled by the respective governments and are heavily subsidized. In Indonesia, an attempt had been made in the summer of 1998 to raise retail oil prices and remove subsidies, but old prices were immediately reinstated to appease strong public opposition. However, in some of these countries, oil prices are in transition to being market-based. India is gradually phasing out the administered pricing mechanism (APM) and moving toward a market-determined pricing mechanism. Oil pricing reforms began last April 1998 with partial price decontrol of some petroleum products. Thus, consumer prices of naptha, low-sulfur heavy stock, fuel oil, paraffin wax, and bitumen were partially decontrolled, subject to a monthly price adjustment. However, prices for gasoline, diesel, kerosene, cooking gas and aviation fuel continue to be administered, and the consumer price of diesel oil is fixed based on import parity pricing up to the ex-storage point level. Kerosene and LPG remain subsidized. Petroleum products remain regulated in Pakistan, but deregulation is being pursued in parallel with the privatization of the Pakistan State Oil, the state-owned petroleum products distributor.

Because oil is an internationally traded commodity, taxation or tariff duty is an issue in oil pricing. And taxation of oil products has become an instrument to meet fiscal (to raise government revenue with low administrative costs), economic (to discourage wasteful consumption of petroleum products and conserve energy), social (to improve the distribution of income), and environmental (to reflect cost of environment externalities into prices) objectives.[26] In Thailand, producer prices, which are agreed upon by the concessionaire and the Petroleum Committee and approved by the Prime Minister, are levied tax. Retail oil prices in Bangkok, on the other hand, are the sum of the ex-refinery prices (import price), excise and municipal taxes, the marketing margin, the Oil Fund contribution, the Energy Conservation Fund contribution, and value added tax (VAT). In Taiwan, the implied net taxes on retail oil price range from 7% on fuel oil and diesel to 46% on premium gasoline.

[25] Thobani (1999).
[26] APERC (2000a).

Electricity prices remain regulated by the Asian governments and do not reflect cost of providing electricity service, or remain below economic levels. One reason for this is the subsidies to some electricity customers, either through direct or cross-subsidies. For example in the Philippines' electric systems, three kinds of cross-subsidies exist: inter-grid, between customer classes of a distribution utility, and between customers of National Power Corporation (Napocor), the state-owned generation and transmission utility. The Luzon grid subsidizes the Visayas and Mindanao grids as well as the small island grids. Within the franchise area of distribution utilities, residential customers are subsidized by industrial and commercial customers. Lastly, the Manila Electric Company, Philippines largest distribution utility, subsidizes all other utility and non-utility customers of Napocor. In Thailand, the "unified" tariff policy reflects cross-subsidies. The Electricity Generating Authority of Thailand (EGAT) charges the Provincial Electricity Authority (PEA) a much lower rate than the Metropolitan Electricity Authority (MEA) even though it is more expensive to supply PEA's franchise areas. Another reason for the low electricity prices is the poor accounting and financial management standards that undervalue assets and underestimate depreciation for instance. In Vietnam, the estimated financial costs of the power utility do not reflect the current and future costs of electricity production such that electricity prices remain below economic levels despite successive tariff increases.[27]

However, the transition to competitive electricity markets, which is envisioned by many countries in the region, is expected to free electricity prices from government intervention or make them reflect actual costs of production. For example, in Indonesia as part of the Power Sector Restructuring Policy, the government managed to raise the electricity tariff levels by 29% in 2000 and plans to make gradual adjustments until electricity prices approach economic levels.[28] In competitive electricity markets, electricity prices will be determined in the spot market or negotiated freely between buyers and sellers of electricity. Transmission and distribution charges (wheeling rates) would remain regulated to prevent monopoly rents. Moreover, electricity prices or initial access costs for some consumers will remain regulated or subsidized to ensure that these consumers receive electricity.

Unlike oil products and electricity, coal and natural gas remain largely energy commodities for power generation in several countries in the region. In most countries, domestic coal prices are determined by the market and based on international prices. Among the exceptions are Vietnam and Indonesia, where a ceiling price for coal used for power generation is imposed; and Japan and the South Korea, where a ceiling price is imposed on domestically produced coal, because of their limited production volume.[29]

Natural gas prices are largely regulated by the government with the objective of promoting gas exploration and development (producer prices) and its utilization (consumer prices). Non-economic pricing prevails in gas rich countries especially (India, Pakistan, Indonesia, China, and Bangladesh), but in the region as a whole, along with industry restructuring and privatization, gas pricing is converging to a market-based framework.

Thus, producer prices are either market-based (Malaysia, Thailand), cost-based (India, Taiwan, Pakistan), or a mix of both (Indonesia). In Malaysia, offshore producer gas price is pegged to the medium fuel oil price ex- Singapore. In Thailand, producer gas prices are linked to WPI (wholesale price index), price of MFO ex-Singapore, US Index of Export Prices, US producer Price Index for oil field machinery and tools, and the exchange rate of baht to US dollar. In India, natural gas prices are covered by the APM that specify a producer price based on costs of production from the South Bassein plus a 15% post-tax ROI and transportation costs plus 10% ROI. The producer prices in Taiwan and Pakistan are also based on cost-plus formula approved by the government. In Indonesia, gas producer prices are negotiated from field to field basis and

[27] Lefevre, et al. (1999).
[28] WEC (2001).
[29]APERC (2000a).

are based mainly on the economics of gas field development. In most cases prices are based on the production cost and market prices of substitute fuels.

Retail gas prices, on the other hand, are pegged to substitute fuels and cost-plus values. In India, for example, since October 1997, the consumer price of natural gas at landfall point has been linked to the international price of a basket of four fuel oils. The linkage increased from 55% in 1998, 65% in 1999, to 75% in 2000. Retail gas pricing in other countries is indicated by Table. But in some countries, gas prices to selected consumers are heavily subsidized. Thus, gas sold to fertilizer plants as feedstock is heavily subsidized in Pakistan, India, China, Indonesia, and Bangladesh. The ultimate aim of such policy is to protect farmers from high fertilizer prices. This policy, however, means controlling prices of gas upstream.

Table 1: Retail gas pricing mechanism in selected Asian countries

	Indonesia	Malaysia	Thailand
Residential	compete with kerosene	indexed to prices of LPG, diesel, and fuel oil	
Industry: fuel	compete with fuel oil	compete with LPG and diesel	40% lower than bulk price of LPG
Industry: feedstock	subsidized		25% higher than local fuel oil
Transport	half the price of gasoline		
Power Generation		104% of medium fuel oil	producer price + cost of transport

Source: CEERD (1999a).

Energy deregulation and the environment

Energy deregulation in Asia is happening in parallel with increasing concern for the state of the environment in the region. This has led to an important question: Will energy deregulation lead to a better environment.

Evidence from developed countries indicates that the impact of deregulation of the electricity sector on the environment is mixed. For example, one study argues that in the US emissions of NOx and CO2 would increase due to wheeling as a result of restructuring.[30] The reason cited is that wheeling causes substitution of expensive nuclear power generation by that of cheaper coal-fired plants. On the other hand, another study reports that electricity market liberalization in the UK and Norway resulted in short-term environmental improvements.[31] In the UK, the removal of coal subsidies accompanying the power sector restructuring caused the substitution of coal-fired power plants with natural gas. In Norway, the establishment of Nordpool facilitated the export of its hydropower generation to other Scandinavian countries, thus replacing their thermal generation.

Environmental benefits of privatization and deregulation

There are elements of privatization and deregulation that can improve the environmental situation: efficiency gains, use of advanced technologies, environmental regulation and use of market-based instruments, and subsidy removal.

[30] Palmer and Burtraw (1997).
[31] Eikland (1998).

Efficiency gains

Privatization and deregulation is aimed at increasing productive efficiency. Competition in fact forces power producers to use their resources more efficiently. This implies increasing factor and fuel productivity, which, in turn, means less fuel consumption per unit of electricity generated and less emission of pollutants. For a given type of technology, improvement in fuel efficiency is achieved through better fuel quality and fuel handling practices.

Advanced technologies

Increase in fuel efficiency could also be achieved through the adoption of advanced technologies such as clean coal technologies and gas-fired combined cycle power plant. These technologies have less environmental emissions. However, IPPs are unlikely to choose more advanced generation technologies (for example, PFBC and IGCC) because of the costs and high risks associated with these technologies. But continued research and development would lower their costs, and hence, increase their attractiveness to IPPs.

Environment regulation and market-based instruments

Privatization and deregulation is happening simultaneously with increasing environmental regulation and management. Environmental regulation of the power sector consists of mandatory environmental impact assessments of new power projects, emission standards, and control of fuel quality and technology. While these regulations initially applied to utilities, IPPs are also required to comply. Moreover, international financial institutions (like World Bank and ADB) have tied financing with environmental compliance.

Privatization and restructuring is also expected to create an environment in which private power producers have incentives to participate in market-based pollution control mechanisms such offsetting and emission trading. Market-based mechanisms are viewed superior to the traditional command-and-control approach in reducing environment emissions, if only because these offer a lot of flexibility in dealing with the environment. Included in these market-based instruments are the flexibility mechanisms developed under the Kyoto Protocol to deal with climate change or GHG emissions. All of these approaches, whether based on command-and-control or market-based, will improve environmental performance under competitive electricity markets.

Subsidy removal

The privatization and deregulation of the electricity sector exerts similar pressure on fuel supply industries. One consequence of this, for example, is the phase-out of subsidies on indigenous fuels (particularly local coal). Subsidies have made these indigenous fuels cheap and have encouraged over consumption. Worst these fuels contribute to environmental emissions. But privatization and deregulation of the electricity sector will encourage a level-playing field for all fuels and thus, limit the over consumption of dirty fuels.

The ALGAS study has also analyzed different mitigation options for the energy sector and reports that energy efficiency (or conservation) measures on both the supply and demand side account for most of the least-cost GHGs mitigation options. In addition, using clean fossil fuels such as natural gas is also a relatively low-cost GHGs mitigation option for many of the 11 countries participating in the study. Furthermore, increasing the level of GHGs mitigation requires moving towards costly new and renewable energy sources. Deregulation has mixed implications on these environment-friendly energy options.

Implications on DSM and energy efficiency

The countries in Asia are at different stages of implementing a DSM program and employ a mix of various measures[32]. For example, South Korea and Thailand are implementing full-scale DSM programs via a mix of several measures. Chinese Taipei is still in the pilot project stage and implementing DSM through time-of-use pricing. Indonesia is also in the pilot project stage, but focusing on energy efficient appliances. In fact, many other countries in the region, including China, Pakistan, Philippines, Bangladesh, India, Sri Lanka, and Vietnam, focus their DSM programs either on time-on-use pricing or energy efficient appliances or both. At the same time, these countries, particularly, Thailand, Philippines, South Korea, China, and India are in the more advanced stages of privatizing and restructuring their electricity supply industry.

In fully competitive electricity markets, the generation segment of the industry has no incentive to implement DSM programs. For example, in Thailand, there is fear among the employees of the department of the national generation and transmission utility managing the country's DSM programs that their office would be dissolved upon the introduction of wholesale competition. However, the remaining monopoly segments—transmission and distribution—could have motivations to continue DSM programs. For example, distribution utilities can continue to use DSM as customer-service programs to maintain and build market shares.[33] Aside from customer service needs, DSM programs under a restructured electricity supply industry could also be motivated by operational and regulatory needs.[34] DSM can continue to be seen as a resource by utilities, with all its environmental benefits. Also because of its environmental benefits, regulators may continue to ask utilities to implement DSM programs. Finally, in the absence of utility funded DSM programs, energy service companies (ESCOs) could invest in DSM programs and profit from them.

Implications on increasing utilization of natural gas

Natural gas consumption in Asia[35] grew 7.6% per year to 239.22 Mtoe in 1990-97, faster than oil (5.1%) and coal (4.2%). This trend will continue in the next ten years or so, although slightly slowing down to 5.5% (in 1999-2010) because of the financial and currency crisis in 1997-99 that dampened economic activities in the region and therefore energy demand. Nevertheless, natural gas share in the region's energy mix is expected to go up to 12.7% in 2010 from 7.7% in 1990. This will be somehow at the expense of oil and coal, whose contributions would slightly diminished but remaining the largest source of energy in Asia.

Developing Asia, particularly China and India, will be the most important source of this high growth in natural gas consumption. Natural gas consumption in China is expected to grow 11.2% per year in 1999-2010, while that in India close to 8% per year. China will have almost equalled Japan as the largest consumer of natural gas in the region by 2010. By that year, India's share in the region's natural gas consumption will have reached 11% from only 8% in 1990. Earlier projections from APEC also show natural gas consumption growing fast in South Korea and Chinese Taipei. Developing Asia will account for 75% of Asia Pacific natural gas consumption in 2010 from 56% in 1990.

In CEERD/AIT's recent survey of coal and natural gas competition in the power sector of APEC economies, including East Asian and Pacific economies, it was found that natural gas is

[32] These measures can be grouped into legislation and regulation, pricing mechanisms, command and control, financial incentives, competition and awards, and education and information campaigns (CEERD, 1999).
[33] Hirst et al. (1996).
[34] Keating (1996).
[35] Including Australasia.

competing closely with coal. Natural gas use in the power sector in Asia has increased remarkably since the beginning of the 1990s. The advent of cost-competitive gas-fired generation technologies and the environmental qualities of natural gas have made it a preferred fuel for power generation.[36] Coal, however, remains attractive because of its abundant supply and stable prices in the international market. Moreover, clean coal technologies are reducing the environmental emissions from coal burning.

The study concludes that the competition between these two fuels is a complex process driven by interrelated factors, including:

- availability of the resource;
- relative prices both in the domestic and international markets;
- environmental policies and regulations, including the international response to global climate change;
- technological developments; and
- on-going deregulation in the power sector, which is the major user of coal and natural gas.

The entry of IPPs have contributed to these trends in the fuel mix in Asia. Most IPPs are using either natural gas or coal. In South Korea, three of the four IPP projects due to come on stream between 2001 and 2004 will burn LNG. Another block of 3,650 MW planned for 2005-2010 will be designed for LNG. In China, the largest market for IPPs in Asia, coal remains as the most competitive fuel choice. The 2 x 350 MW Laibin B, which is the first BOT by Chinese standard, is using coal. The 2 x 700 MW Zhuhai, which qualifies as a BOT by international standard, is a US$1.2 billion power project using coal. Shandong Zhonghua Power Co., the largest IPP in China to date, is building four coal-fired power plants with a combined capacity of 3,000 MW at a total cost of US$2.2 billion. In Thailand, coal is competing closely with gas. Of the seven approved IPP projects, four with a total capacity of 2,394.3 MW will be using gas, and the other three projects will run on coal, but with a higher combined capacity of 3,441 MW. In Vietnam, all of the gas-fired combined cycle planned after 2005 through 2020 (with a total capacity of 7,200 MW) are candidate for BOT implementation.

The choice of fuel dictates the choice of technology. With increasing preference for natural gas, gas turbines have been filling in the demand for new capacity worldwide. Asia has consistently topped the market for gas turbine capacity additions.[37] Steam turbines, however, remains popular in Asia, indicating preference for solid fuels.[38]

Gas-fired power plants are often the particularly attractive option for IPPs because of:[39]

- their relatively low capital construction cost;
- the use of a well-established technology;
- their shorter construction lead times;
- their relatively high fuel conversion efficiency; and
- their lower environmental impacts.

Ultimately, however, the choice of fuel and technology by IPPs is driven by:[40]

[36] Natural gas emits 40% and 20% less CO2 and 60% and 30% less NOx than coal and oil, respectively. Its SOx emission is practically nil.
[37] Schuler (1997).
[38] Burr (1996).
[39] Apogee Research (1997).
[40] CEERD (1999b).

- the availability of fuel;
- relative fuel prices;
- attractiveness of the corresponding generation technology, in terms of:
  - cost;
  - efficiency;
  - construction/installation lead times; and
  - environment compliance;
- environment considerations; and
- cost of generation.

Implications on renewables

New and renewable energy sources have become attractive national energy options because of their environmental benefits as well as a means of increasing energy access in areas in the developing world that could not be served by the electricity networks.[41] New and renewable energy technologies have occupied significant market shares in Asia since the early 1980s.[42] In fact, some Asian countries have implemented these technologies at equivalent or higher level than developed Western countries. Most have already formulated policies for the development and promotion of new and renewable energy technologies or are in the process of doing so. China and India, for example, have designed ambitious plans and programmes to strengthen the contribution of these technologies to their total energy supply. Developments in renewable energy, however, have been largely as a result of direct and indirect government intervention.

Table 2 Environmental emissions of electricity options

Electricity generation option	GHG emissions (kt eq. CO_2/TWh)	SO_2 emissions (t SO_2/TWh)	NO_x emissions (t NOx/TWh)	Particulate matter emissions (t/TWh)
Hydropower with reservoir	2-48	5-60	3-42	5
Diesel	555-883	84-1,550	316+-12,300	122-213+
Modern coal power plant: bituminous coal	790-1,182	700-32,321+	700-5,273+	30-663+
Old coal power plant: lignite	1,147-1,272+	600-31,941+	704-4,146+	100-618
Oil thermal w/o scrubbing	686-726+	8,013-9,595+	1,386+	
Nuclear	2-59	3-50	2-100	2
Natural gas CC	389-511	4-15,000+	13+-1,500	1-10+
Biomass: energy plantation	17-118	26-160	1,110-2,540	190-212
Wind power	7-124	21-87	14-50	5-35
Solar PV	13-731	24-490	16-340	12-190

Source: Adapted from IEA (2000), p. 8.

[41] Actually, developed countries were the first to explore the potential of renewables, but for energy security reasons, particularly in response to the oil price shock in the 1970s.
[42] Timilsina and Lefevre (1999).

Privatization and deregulation is posing threats on renewables by "changing the rules of the game, and by reducing or eliminating traditional support mechanisms…As markets liberalize, government's ability to intervene directly to support renewables has diminished. Price supports, mandatory purchase agreements, capital subsidies, and fixed prices contradict the fundamental premises of market liberalization."[43] Investors in competitive electricity markets would not have incentive to choose *new* renewables that remain expensive options.

However, a number of instruments are available to make renewables attractive options in a deregulated electricity market. In the European Union, which targets to increase the share of renewables in the generation mix to 12% in 2010, the approaches or instruments being considered include: (1) a network access system; (2) a tendering system; (3) internationally harmonized energy taxes on production; and (4) substitution of heat for electricity.[44] In the network access system, electricity generated from renewables are guaranteed access to the grid and paid a price set by the state. In the tendering system, instead of setting the price, the state decides on the site, size and type of a renewables plant, and set a fund for the project in the form of a fixed subsidy. Electricity produced from various sources may be taxed according to their emissions. In this case, renewables could become more attractive because of their low emissions. Some renewables (biomass, solar) are used for heating purpose to substitute for electricity. Renewables can also be promoted by reflecting in the tariffs the real cost of transporting electricity.

On the other hand, others argue that dynamics of electricity sector reforms actually offer opportunities for new and renewable energy sources. The privatization and break up of the national electric monopoly and the unbundling of the electricity system into its different functions increase opportunities for distributed or decentralized energy systems (including cogeneration systems) that are fuelled by renewables. Moreover, the increasing concern for the environment calls for internalizing the environmental costs of generation technologies. This would make renewables more competitive and increase its market value. Experience in developed countries that restructure their electricity sector indicates that a large number of consumer contract renewable electricity, or *green power*, from merchant power producers (generators in competitive electricity markets), despite its higher price.[45] The public awareness campaigns conducted by government and non-government organizations have been largely responsible for such consumer response.

Conclusion

The Asian energy sectors, in particular the oil and gas industries, both upstream and downstream, and the power sector, are at different stages of deregulation. The privatization trend is definitely sweeping all the energy industries. But Asian governments are proceeding cautiously with it in terms of selling state-owned enterprises that monopolize especially the power sector and upstream oil and gas industries. Rather, many governments have opted to opening up the sectors to private and foreign direct investments (as against outright sale of assets). In upstream oil and gas, the result of this approach was the different contractual arrangements in oil and gas exploration and production. In the power industry, the opening up to private and foreign direct investments led to the mushrooming of independent power projects in the region, largely because in response to the strong growth in electricity demand and the inability of these economies to finance the needed capital investments. IPPs have been successful in meeting the expected growth in demand, but the financial crisis in 1997-1998 has exposed flaws in this kind of arrangement, which are typical of a single-buyer model, and called for more competitive arrangements or ultimately consumer choice. In addition, the financial crisis has renewed the thrust towards privatization, which is viewed as

[43] Bess (1999), p. 29 and 30.
[44] Havskjold (1999).
[45] ADB (2000).

the long-term solution to structural weaknesses not only in the energy industries, but in the economies as a whole.

In contrast, downstream oil and gas industries are largely in private sector hands. But governments continue to intervene in terms of retail pricing. In quite a number of domestic markets, retail oil prices continue to be regulated or controlled by governments. But oil pricing is in transition to being market-based, and many countries have actually deregulated petroleum product prices. Natural gas prices at end-user level are based on substitute fuels and therefore largely market-based.

Electricity prices remain regulated although there have been efforts for these to reflect economic cost. They will remain so until wholesale and retail competition has set in. Even then, transmission and distribution charges will continue to be regulated and lifeline rates will need to be maintained for very small electricity users.

The ultimate reason for deregulation is economic efficiency in the energy industries. However, while the economic benefits of deregulation are desirable, there could be implications to the environment that call for policy intervention. The environmental implications of deregulation are actually mixed. For example, the spread of IPPs and the private attention to risks have increased the utilization of environment-friendly natural gas-fired technologies that are deemed cost-effective. But deregulation could have negative implications on renewables and energy conservation and efficiency. In this case, policy should intervene so that these most sustainable energy options are not left out in deregulated energy markets.

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