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Issues in Global Natural Gas: A Primer and Analysis

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Issues in Global Natural Gas: A Primer and Analysis

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Abstract

This paper discusses the rising profile of natural gas in global energy, factors constraining its further development, the gas contracting process, and the absence of a global market, which is analyzed in the context of the economic rent in the gas price and the opaque nature of gas contracts. A proposal for rationalizing the trade to ease these constraints is offered. Gas pricing, and factors driving demand are also analyzed using evidence from the literature. FDI can help to monetize some of the 'stranded' gas reserves, but success would depend on an investor-friendly climate, including appropriate tariff regimes in the domestic markets.

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I. Introduction

Natural gas has made a strong comeback in the global energy balance since the mid-1970s as a direct response to the increase in crude oil prices that started in that period. This development was given further impetus from the late 1980s in the light of new concerns about a potential global warming and climate change brought about by rising emissions and concentration of greenhouse gases (GHGs) in the atmosphere. The low carbon intensity of gas (lowest among the fossil fuels) has made it the fuel of choice from an environmental point of view, and opened new opportunities for countries that are endowed with exploitable reserves.

Most current projections foresee a rapid growth in the demand for gas in the next two decades: the *International Energy Agency* (2000), for example, forecasts an annual growth rate of 1.9 percent up to 2020 in its base case scenario. It is also widely acknowledged that the huge size of proven gas reserves is sufficient to accommodate rising demand over several decades. The main constraint to the sector's development is the costly transport infrastructure and the high cost of delivering gas to consuming markets, which has prevented the emergence of a global gas market. Consequently, gas trade is still largely localized. There is, thus, an investment challenge—both at the level of upstream gas exploration and development, as well as in terms of constructing the necessary transportation infrastructure to facilitate international trade in gas and its use domestically. There are also other constraints arising from inappropriate regulatory regimes, particularly in relation to the domestic pricing of gas and gas-based utility services, which have discouraged the investment needed to realize the full benefits of this fuel.

Many transition and developing countries with gas reserves are either in the process of developing them, or expanding their existing production capacities to take advantage of the opportunities afforded by the potentials of gas. There is relatively limited institutional knowledge about the gas sector, compared to oil, which dominates the energy sector. While the Fund is not generally involved with the technical work on gas projects in member countries, its surveillance work would require more widespread understanding of the underlying issues as more gas projects come on stream in the future. This paper has the following objectives: to provide a primer on natural gas (sections II-IV); analyze the factors that have prevented the emergence of a global gas market and offer a proposal for restructuring and rationalizing the trade (section V); draw evidence from the literature on the determinants of gas demand (section VI); and considerations underlying the pricing of natural gas, followed by a brief summary of the paper (sections VII and VIII). A short appendix discusses the structure of the sales and purchase contract for gas.

II. The Natural Gas Chain

Gas occurs either in the form of natural gas (methane and ethane) or as field liquefied petroleum gas (LPG)—butane and propane—which, together, constitute the basic hydrocarbon building blocks for petrochemical products, or feedstock for power generation and water desalination, as well as for a variety of industrial, commercial and household uses. Natural gas occurs as 'associated' or wet gas (i.e., as part of liquid petroleum), or as 'non-associated' (dry) gas. Wet gas generally contains greater amounts of the higher hydrocarbons (ethane, propane, butanes, and pentanes), and is a useful source of commercial LPG, while dry gas (mostly methane) is used more as fuel in power generation. Dry gas offers greater flexibility for hydrocarbon producers because its exploitation is driven by its own technical and marketing logic, rather than as an undesired by-product of crude oil.[2] For OPEC producers, for example, the output of associated gas is usually constrained by crude oil quotas.

Natural gas is transported either by pipeline, or by tankers (as LNG). The mode of transportation usually depends on the distance between the gas field and the market: pipeline transportation is more economical over short distances, while tanker shipping is more attractive over greater distances. An LNG chain consists of three main modules: the upstream (production and liquefaction), transportation (through tankers), and downstream (receiving terminal with associated facilities). The upstream module involves the actual production of gas, piping it into giant refrigerating units where it is frozen to a temperature below −161.5 degrees Celsius, which is the boiling point of methane, and transformed into a liquid state and stored. The gas is subsequently passed through a separation unit to separate non-methane gases. Other forms of natural gas, such as ethane and propane, have boiling points above this level, and separation of these gases takes place at the cooling stage. From the storage facilities, the liquid products are loaded into tankers that are specially designed to maintain the required temperature for the duration of the journey to final markets. At the downstream end (the receiving terminal), the gas is reheated and subsequently piped to the purchasing utility or distributor for onward transmission to final users (see Chart 1). The complete cycle, from the initial pumping of the gas into the holding unit, to freezing, separation, and storage is called a "train".

From an investment viewpoint, each of the three modules is expected to be financially viable as investors often choose to invest in one or another, rather than in the entire chain. However, for practical purposes, the transportation module is usually combined with either the upstream or the downstream in terms of ownership and operation although it is sometimes left to a third party. Pipeline operations are usually based on long-term contracts, with the charge being related to the load pattern. The pricing of pipeline service is based on the principle of 'causal responsibility', which is intended to reflect the cost imposed on the system by each user. The charge on peak users, for example, includes a fixed cost element (for the pipeline capacity, on grounds that the pipeline was built to serve such users in the first place), as well as a 'commodity' charge (for the fuel) and other variable costs (operating and maintenance). Off-peak users are not charged the capacity (fixed) cost element. Also important is the load factor: in general, a high load factor results in a low average delivered price for gas and vice versa, which largely explains the divergence in prices charged to large and small gas users.

Pipeline transportation has the advantage that it can be connected to existing grids (as in Europe and North America), but lacks the flexibility of redeployability in the event of unfavorable

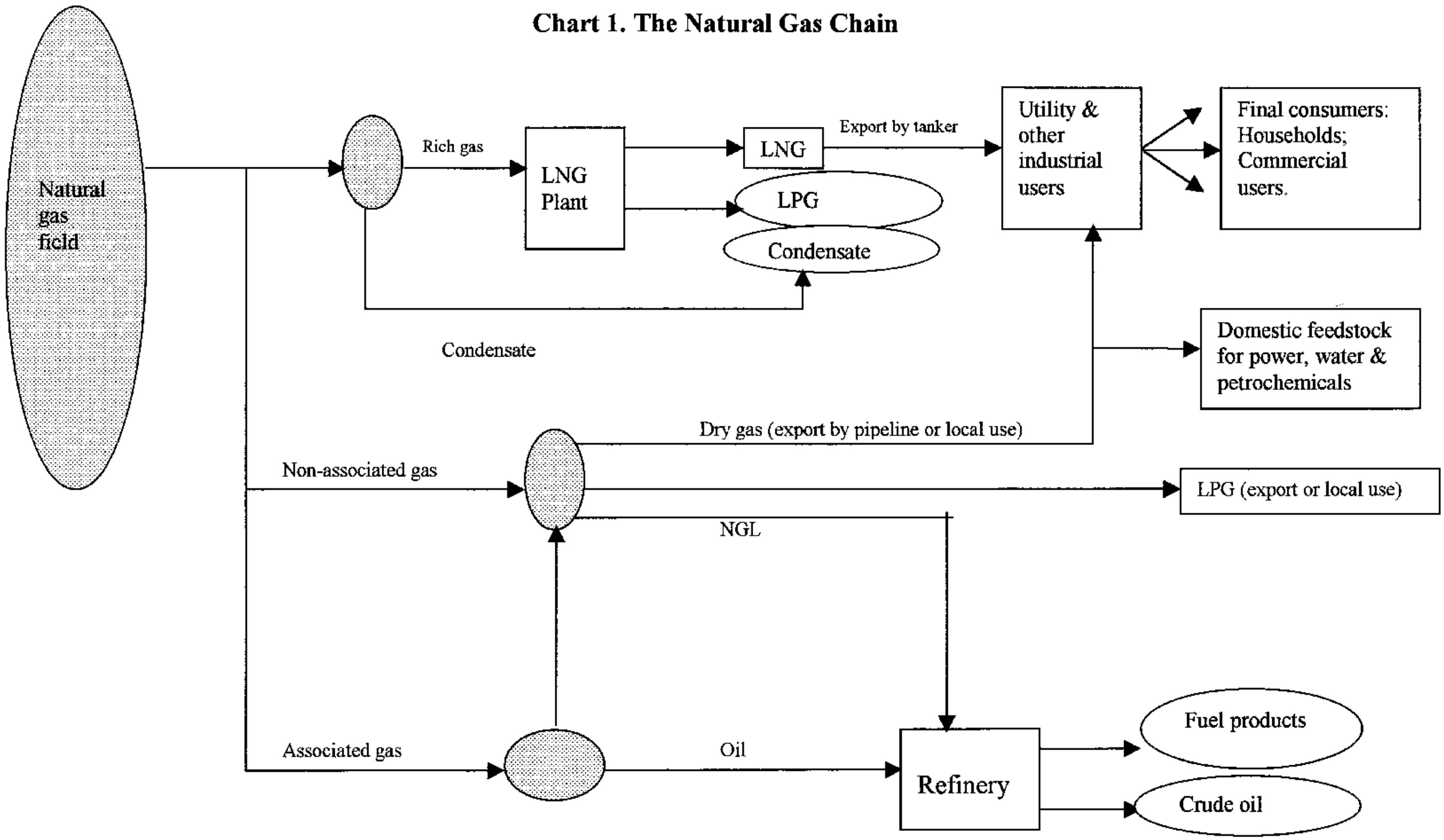
[2] As a by-product, associated gas is usually gathered and processed (where the facilities exist) or re-injected to maintain reservoir pressure, or otherwise flared.

developments (such as civil strife, war, or adverse political relations). In contrast, LNG infrastructure can be redeployed by negotiating new sales and purchase agreements (SPAs), or selling on a spot basis. LNG agreements tend to be less complicated than those for pipeline gas because they are generally bilateral in nature (unlike pipeline, which is often multilateral because of transit rights). Further, LNG projects tend to cost less than pipeline gas projects and, because the chain can be broken down into logical independent segments, its financing can proceed on a modular basis, thereby making it easier to raise capital. Where pipeline gas has an edge, this is usually self-evident, as in the case of sellers and buyers that have land contiguity and distances relatively short, or where tanker transportation is clearly unfeasible. These various considerations have influenced the development of natural gas projects, and the evolution of the gas market. The preponderance of long term SPAs, for example, is one of the factors that has contributed to limiting the emergence of a global market in natural gas. These agreements are, by definition, fixed over long periods, and are specific in several details; they represent long-term commitments between the contracting parties, which may not always reflect short-term developments on the international gas market.[3]

The gas chain described above evolved into a vertically integrated structure from the early days of the industry, based on the need of gas producers to provide a means for delivering the gas to their customers. Where pipeline owners were independent entities, they traditionally also played the role of marketing the gas to final users (the so-called 'merchant-pipelines'), because they have the most incentive to secure buyers, thereby guaranteeing that their pipelines are not idle. The sector's infrastructure requirements tend to capital intensive, involving large, costly and specialized non-redeployable assets, which may not be attractive to investors except with the assurance provided by centralized decision-making on volumes and scheduling coordination offered by vertical integration (See Williamson, 1985, for an exposition of industrial organization in the context of vertically integrated companies, and Teece, 1990, in relation to the gas industry). The integrated structure thus emerged as a 'natural' evolutionary process of the sector's development, and is seen by advocates as the best way to encourage the required investments and ensure supply security. In particular, Teece has argued for the integration of the merchant and transportation functions of the gas chain "... if scheduling, information and capital-utilization economies are to be obtained". He further notes: "It is not accidental that nowhere in the world ... has the natural gas industry evolved by itself into a fragmented structure. Integration efficiencies often dictate bundling". However, this form of industrial organization has since come under public scrutiny in many countries, and the gas chain has been "unbundled" into its component parts in recent years, in order to enhance competition (see section IV).

[3] There are usually price revision clauses in the SPAs, but these tend to relate more to developments in the particular end-user (buyer) market than to global developments.

Chart 1. The Natural Gas Chain



III. Natural Gas in the World Energy Balance

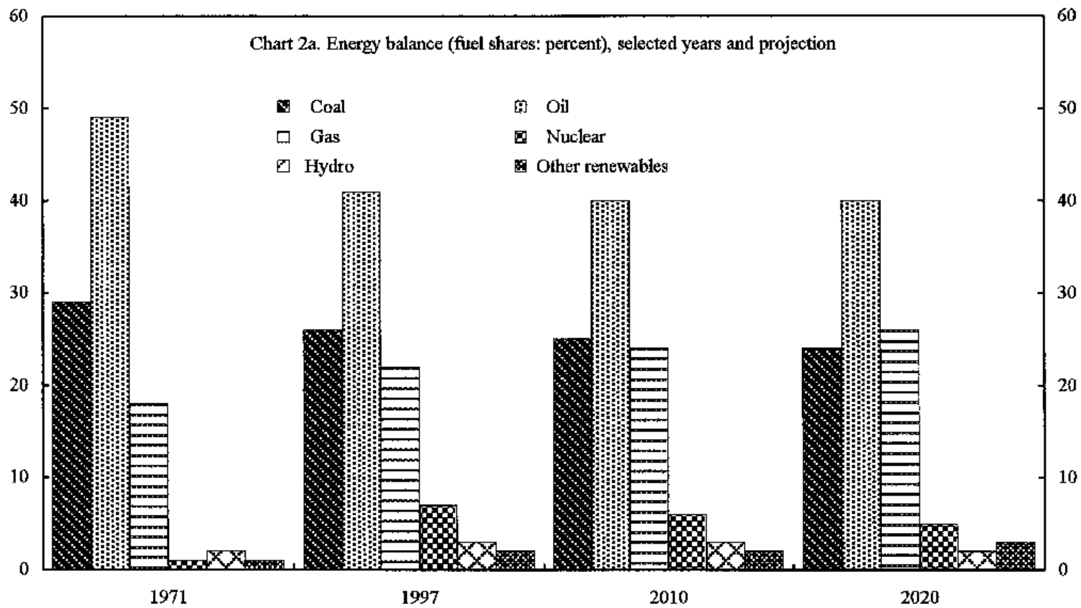
The structure of global gas demand

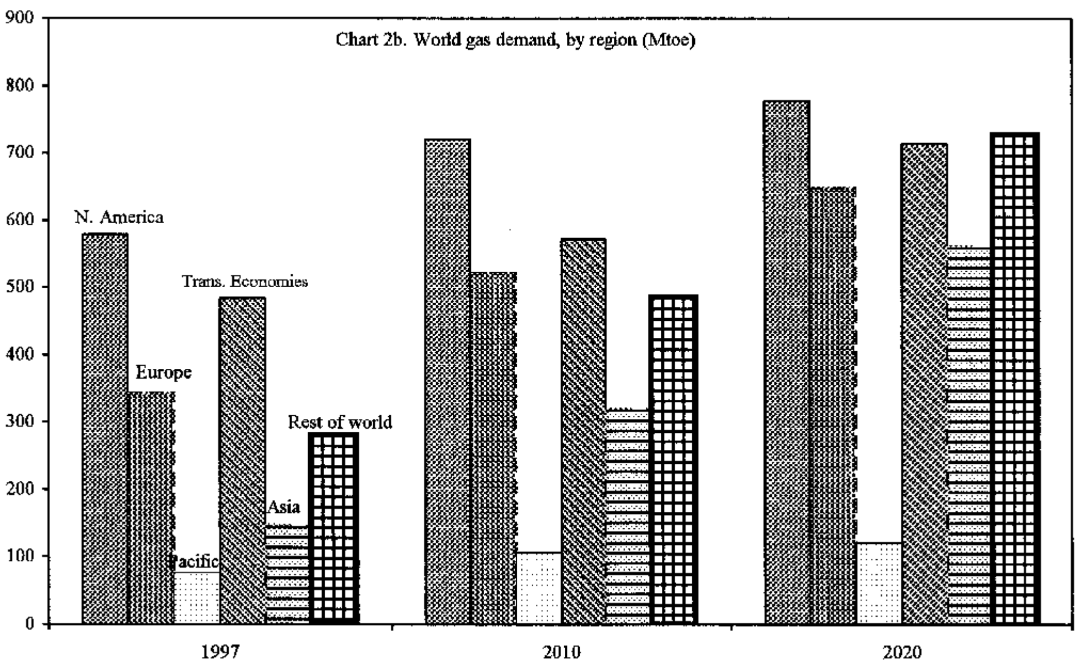
Natural gas is an important component in the global energy balance, and its image has been further enhanced in recent years because of its environmental credentials. According to IEA estimates, global final consumption of energy increased by about 74 percent between 1971 and 1997; during the same period, the share of natural gas in total primary energy rose from about 18 percent to about 22 percent (chart 2a). In contrast, the share of coal declined from 29 percent to 26 percent over the same period, while that of oil fell from 49 percent to 41 percent. The share of coal in the energy balance would have been even lower but for the deliberate policy to protect the sector in countries where there are indigenous reserves, such as Germany and Spain; and the UK up to the end of the 1980s. These policies have been pursued in spite of the reputation of coal as a 'dirty' fuel because of a desire to promote energy self-sufficiency, as well as using it as an instrument of regional policy to protect coal-dependent communities (Okogu and Birol, 1993). Most of the switch from oil has taken place in the power generation sector where the share of oil fell from 22 percent in 1971 to 9 percent in 1997. In contrast, natural gas has retained its share in power generation from 1971 to 1997, and it is projected to grow rapidly in the future. China and India are large users of coal, relying on their large reserves of the fuel rather than having to import cleaner, more expensive, substitutes.

The forecasts for 2010 and 2020 are for increases of 127 percent and 174 percent respectively (compared to 1971) in total energy demand, with the share of gas rising to 24 percent and 26 percent, respectively. In absolute terms, this implies that the demand for natural gas will almost quadruple over the 1971-2020 period (Table 1). Projections of the share of oil in power generation for 2010 and 2020 indicate further declines to 7 percent and 6 percent respectively, while the share of gas is expected to rise to 23 percent and 27 percent respectively. Coal is expected to maintain its share of the power generation sector at the current level of 44 percent. Gas has also increased its penetration of industry and other sectors and is projected to show a similar robustness in the future; however, its share of the transportation sector remains small, as petroleum continues to dominate it, accounting for about 96 percent of the fuel mix in the sector, as alternative fuels are still not commercially viable and are much less efficient.

The structure of global gas demand (in 1997) shows that 30 percent of total consumption is in North America (mostly the United States), 18 percent in the EU, and transition economies jointly accounting for 25 percent. The shares in 2020 are projected to show a decline to 22 and 20 percent respectively for North America and transition economies, in favor of Asia and the rest of the world, although rising substantially in absolute terms. Europe will maintain its share, Asian demand will almost quadruple, while demand in Latin America, Africa and the Middle East would almost triple over the same period. The OECD and Asia would jointly account for about 59 percent of gas requirements, with an estimated import dependency of 42 percent. Given the structure of reserve ownership, it is clear that there will be huge trade flows in gas in the future, which makes the early development of gas fields and supporting infrastructure so crucial. Chart 2b shows projected gas demand by region.

Chart 2. World energy balance, and gas demand





Source: International Energy Agency, *World Energy Outlook*, 2000.

Table 1. World primary energy balance, selected years
(Million tons of oil equivalent, and percent share)

	1971	1997	2010 (proj.)	2020 (proj.)
Coal	1,446	2,255	2,820	3,350
Percent share	29	26	25	24
Oil	2,461	3,541	4,589	5,494
Percent share	49	41	40	40
Natural gas	**900**	**1911**	**2724**	**3551**
Percent share	**18**	**22**	**24**	**26**
Nuclear	29	624	690	617
Percent share	1	7	6	5
Hydro	104	221	287	336
Percent share	2	3	3	2
Other renewables	72	189	279	361
Percent share	1	2	2	3
Total primary energy	**5,012**	**8,743**	**11,390**	**13,710**
Percent share	**100**	**100**	**100**	**100**

Source: International Energy Agency, *World Energy Outlook, 2000.*

Gas supply

The demand developments discussed above have inevitably created their own supply. With the rising profile of gas in the last two decades, major consuming countries have developed their indigenous reserves (where they exist) and/or increased their imports from sources that are conveniently located near to these markets. However, the extent of the gas trade is limited by its localized nature, which is a major source of difference between the oil and gas markets. Whereas the oil market is truly global, the gas trade is constrained by the costly infrastructure necessary to bring about unfettered transaction between producers and consumers (see next section). This limits the substitution possibilities of gas for oil. The fact that gas is available in a particular location does not make it a substitute for oil unless it can be transported to the relevant market at a reasonable cost, and its use is technically feasible.

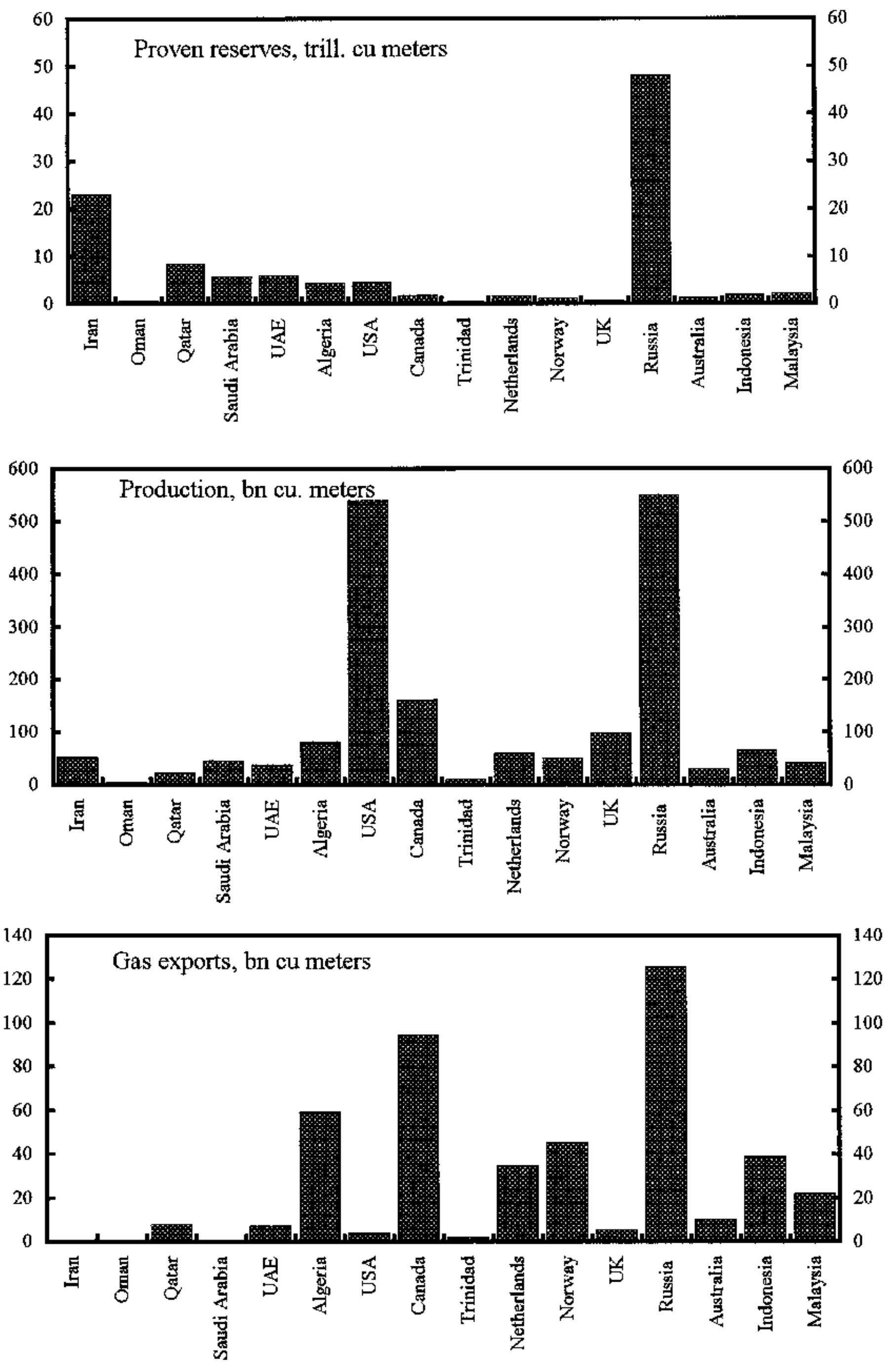
The extent to which gas can compete with other fuels depends critically on the delivery cost, a significant part of which is accounted for by transportation. One of the most obvious areas where a gas-for-oil substitution program can be fruitfully initiated is at the domestic level for countries that produce both oil and gas. Since the market for oil is more developed, increased use of gas in the domestic economy would release more oil for export. However, this would involve a substantial investment in the construction of the necessary infrastructure, which may be viable only with the existence of an appropriate tariff structure for the relevant utility.

Chart 3 provides a representation of the proven reserves, production, and export of natural gas in 2000. Russia leads the world in terms of the size of reserves (with 33 percent of the world total), production (24 percent) and exports (25 percent), while Canada with just 1.2 percent of the world's reserves accounts for about 19 percent of exported gas (obviously capitalizing on its proximity to the American market, with its good system of supporting gas infrastructure). Similarly, Algeria has 3.1 percent of the world's reserves but the early development of its reserves means that it now accounts for about 12 percent of total world exports. In contrast, Iran that has the second largest reserves (15.3 percent), produces a relatively small amount of gas (about 2 percent), and does not feature in the world export table at all, indicating that there is a large investment gap in the gas sector of the latter country. Indeed, Iran imports some gas from neighboring Turkmenistan (2.65 billion cubic meters in 2000) even though its proven reserves are eight times the size of those of the latter country. All of Russia's gas exports go to Europe and Turkey by pipeline, with Germany absorbing about 28 percent.

In some cases, the gas reserves are not developed because the country does not have sufficient capital of its own and the field is not sufficiently attractive for foreign investors. Related to this is the fact that the domestic price of gas may be controlled by the government, which, for socio-political reasons, may find it difficult to liberalize it. In such a case, the national gas company may be unable to mobilize the necessary capital to develop or expand production, as has been the experience of many developing countries that have huge reserves of 'stranded' gas. The absence of market-based tariff regimes in many developing and transition countries has usually discouraged private investment in the sector, and partly explains the ubiquity of state-owned utilities that rely on budgetary subsidies. It is also a major factor in the slow pace of privatization of these entities in many of these countries.

The supply cost of gas can be quite high, involving huge initial capital outlays for exploration, field development, liquefaction, pipeline, and shipping. Some projects factor out the shipping module, as a way of reducing the size of the required initial capital investment, by contracting the services of independent shippers. In addition, there is a marketing cost, particularly at the early stage when the producer must search for potential customers, and also convince financiers of the attractiveness of the project. This latter aspect boils down to a cash flow analysis under various cost and price scenarios that integrate all of the above considerations.

Chart 3 . Natural gas reserves, production, and export, 2000



Source: BP-Amoco Statistical Review of Energy

IV. Factors Constraining the Development of Gas

Gas reserves are more widely dispersed around the world than oil.[4] *BP-Amoco* estimates world proven reserves of gas at the end of 2000 at 150.2 trillion cubic meters—sufficient to last for about 61 years at present rate of consumption. However, there are constraints in the form of limited transportation infrastructure, and the high cost of developing gas fields and associated facilities, as well as inflexible regulatory regimes in many gas-bearing countries that prevent the price from performing its proper signaling role. Pipelines carry about three-fourths of total traded gas, with LNG carriers accounting for the balance; most of the LNG tanker capacity is of a dedicated nature in the sense that it is tied to existing SPAs. The world requirement of LNG carriers is projected at 250 vessels (each of capacity 125,000-135,000 cubic meters) by 2020, of which the Asia-Pacific region, which presently accounts for 74 percent of world LNG trade, would require about 160.[5] The United States *Energy Information Administration* (2001, Internet Edition) has estimated that as of February 1997, some 11,000 miles of gas pipeline were under construction, and over 34,000 miles of gas pipelines were planned for years beyond that.

The constraint is similarly severe at the domestic level in many countries. A pipeline network from the gas gathering centers to utility plants needs to be in place, while final users (households and firms) have to be connected to a national or municipal grid. Such network is expensive to build, and generally scanty or absent in many developing and transition countries that own natural gas reserves.

The fact that the development of a truly international trade in gas is constrained by transportation is clearly evident from the international trade statistics in gas. Of the 2,405 billion cubic meters of gas consumed in 2000, only about 22 percent was traded across international borders, with pipelines carrying about 75 percent of this. At present, the main markets for internationally traded gas are to be found in the EU, accounting for about 58 percent of the total (supplied mostly by Norway, Russia and Algeria)[6]; North America for 21 percent;[7] and Japan, which imports most of the rest[8]. All of Japan's imports of gas are in the form of LNG, mostly

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[4] It is true, however, that gas reserves in North America and Europe (where the bulk of the fuel is consumed) is now on the decline, but this has more to do with the fact that exploration and development is yet to be carried to its full potential in some cases.

[5] See Tokinao Hojo (2000).

[6] There are other smaller suppliers, including Libya and Nigeria.

[7] Virtually all of the North American gas trade is through pipeline but, since 1998, a small trade in LNG has taken root (exports from the US to Mexico), mostly related to the increase in manufacturing facilities located on the Mexican side of the border (see Todaro, 2001, for a discussion of the United States gas trade).

[8] India, South Korea, Taiwan and Singapore are also becoming important importers for gas.

because of its geographical location vis-à-vis its suppliers. There is also some trans-border gas trade in the southern cone of South America, while a regional gas pipeline is soon to be constructed in West Africa.

Some major oil companies have recently begun to consider the gas-to-liquids (GTL) technology option under which they will convert the gas into liquid petroleum on site in remote fields, and subsequently transport the products to final markets in the usual way. Examples of these include a joint project between *Shell* and *Sasol-Chevron* involving some uncommitted gas in Australia; a proposed Shell middle distillate plant in Argentina; and a proposed Sasol GTL project in Qatar. However, the success of these projects would depend on the price of oil, with industry sources suggesting US$14 per barrel as the break-even point.[9]

The move towards deregulation of gas markets

In an attempt to overcome some of the constraints in the gas market, various authorities have initiated policies designed to deregulate the industry, for example, through unbundling the system into logical segments—production, transmission, and distribution. The rationale for this de-integration process is based on the belief that this would result in increased competition at the various stages, guarantee supplies, and produce competitive prices for consumers. In the European gas market, the impact of deregulation has been a dramatic increase in gas-on-gas competition in recent years, with Russian, Algerian and other long haul exporters competing very effectively with Norwegian gas. Indeed, many European countries are increasingly relying on non-European suppliers rather than on Europe-based producers like Norway.

A related issue in the efforts to tackle the constraints facing the industry is through third party access (TPA) arrangements, under which an outside gas exporter is given access to the pipeline network of local operators so long as spare capacity exists. This is at the heart of the deregulation process in the European Union, and has made gas trade more competitive.[10] While this is expected to ease the constraint somewhat, the fact remains that the pipeline capacity is limited, and would have to be expanded to accommodate increasing demands from third parties. Besides, there is still some resistance to the concept in some European countries, which would have to be overcome before this factor can deliver its full potential. Longer term, technological improvements in long haul transmission of gas could reduce the cost and make remote fields more commercially attractive. A third source of potential attractiveness of remote gas fields is GTL processing technology discussed earlier.

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[9] See *Petroleum Economist,* May 2001.

[10] The EU's gas directive made it mandatory that at least 20 percent of each member country's gas market be opened to competition, effective August 10, 2000 (see *Petroleum Economist,* May 2000). Access to the local pipeline network is a pre-requisite for this to function effectively.

The implied superiority of deregulation (based largely on the attractiveness of greater competition and efficiency) has, however, been questioned in the context of the gas industry by a number of studies, including Teece (1990); Jensen (1992); and Banks (1997). This body of critique, as discussed earlier, revolves around the argument that vertical integration is more suitable for industries with large investments in specialized, non-redeployable assets and that the gas industry should be left to operate in this mode in order to attract the required levels of investments.[11] This, in turn, would ensure adequate supplies and stable prices since integrated gas companies are in a better position to program volumes in such a way that they match demand. This argument appears to have been vindicated by the admission by the *Energy Information Administration* (of the US Department of Energy) to the effect that since the onset of deregulation: "The wellhead price has moved from a relatively stable but high price environment during the early 1980's to one with a great deal of price volatility but at lower price levels". The lower price is the result of increased competition, but this has also "...created a more dynamic system that responds quickly to changes in the amount of natural gas consumed or supplied" (EIA, 2001, *op cit.*). The principal criticism that integrated markets tend to stifle competition and keep the price higher than it would otherwise be, is clearly borne out in the case of the US. Thus, there is an implicit trade-off between supply security and low, albeit volatile, prices and the United States, Europe and several other countries appear to have opted for deregulation and liberalization in line with global market trends of recent years.

Role of foreign direct investment

In the light of the constraints identified above, the question arises as to how the role of foreign direct investment can be increased in the gas sector in order to meet the investment challenge of the next 10-20 years, both in gas field development as well as in transportation facilities to satisfy the expected growth in demand. As indicated earlier, the IEA projects an annual growth rate of 1.9 percent for gas up to 2020.[12] On the basis of this growth assumption, and using the *BP-Amoco* consumption data for 2000, gas requirements could rise to about 2,820 billion cubic meters by 2010, and to 3,405 billion cubic meters by 2020. If it is further assumed that most of the extra gas would be traded across international borders since it would come from outside the main consuming centers, then the transportation infrastructure would have to be expanded by about 25 percent by 2010, and by nearly 50 percent by 2020. Most of the demand increase would be in North America, Europe, and Asia Pacific due to secular growth, but also as a result of fuel switching to meet the Kyoto environmental commitments.

Given this scenario, the long-term prospects for gas appear bright, and could make the sector continue to be attractive for foreign direct investment. How attractive it actually turns out

[11] Long-term contracts are seen to be capable of playing a comparable role, as long as contracts can be enforced.

[12] Other sources, such as the US *Energy Information Administration*, put it higher, at over 3 percent.

to be would depend on several factors, including oil price developments since the price of gas is still tied to that of oil. The opportunity for investment in energy projects, including gas, has decreased significantly since the Asian crisis of 1997, with financiers showing greater risk aversion than in the past (see World Bank, 2000). This has been compounded by the nascent slowdown in global economic activity generally, and the difficulties recently experienced by many emerging and transition economies. This has raised the threshold of the quality of projects that are capable of attracting risk capital although the expected long-term growth in demand for gas would ensure that there is no shortage of capital in the sector if the rate of returns justifies it. As with other areas, investment decisions in the gas sector are usually based on the value of the assets and envisaged cash flow position of the project, in addition to whether a long-term sales contract has been secured for the project with a creditworthy buyer. In some cases, governments have found it necessary to provide guarantees in order to give comfort to potential investors.[13]

Whether the required private investment would actually be forthcoming would have to be viewed at two levels: gas development for the domestic market of the host country, which depends on the existence of both adequate demand and an appropriate tariff regime; and gas production dedicated for exports. In order for the domestic market to be attractive to private investors, the investment and regulatory regimes have to be right to make such a venture profitable. Assuming the existence of an investor friendly environment, there would still need to be sector-specific requirements, including a liberalized utilities market with a tariff structure that guarantees adequate returns on capital. The ability of gas-based utilities to pass on the full effect of any changes in the cost of gas through the energy chain to final consumers is an important requirement for potential investors. Where such conditions exist, as in a number of Asian and Latin American countries, private investment in gas-related utility projects has thrived on a build-operate-own (BOO) or build-operate-transfer (BOT) basis. It has been more difficult in other countries without such arrangements, which partly explains the low utilization of gas in the domestic markets of many countries that own huge reserves. However, government continues to have a role in pricing, both within the framework of instituting a regulating agency, as well as during periods of sharp price swings, in terms of balancing the need for financial viability of the power company with the interest of consumers. In many developing and transition economies, the electricity and water tariff rates are fixed by the government—usually at below break-even levels—which tend to discourage private developers. The recent agreement between Saudi Arabia and international oil companies (IOCs) to allow the IOCs to produce gas in the upstream sector for utilization in downstream projects such as petrochemicals, water desalination and power generation, represents another model of attracting FDI to the gas sector.[14]

[13] There are other variants of this arrangement, including an agreement to dedicate all or most of the proceeds of the gas sales to repaying the debt through an escrow account.

[14] The projects are expected to involve investments of about US$100 billion over a period of twenty years. The discussions on the fiscal regime are still in progress, but the outcome would, presumably, provide for an adequate profit margin for the IOCs through tariff liberalization or some compensatory arrangement.

Gas-based projects that are dedicated for exports have tended to do better generally in terms of attracting FDI since the price is determined on the international market and the cash flow is guaranteed on that basis, as in the case of Qatar LNG projects financed partly by foreign private capital; Kuwait's joint petrochemical project with Union Carbide, etc. Starting from this premise, it would appear that as long as the market conditions justify it, international capital would be available to finance export-oriented gas projects. The market prerequisites center around having a secure effective demand, preferably in the form of a long-term contract. A combination of continued progress in the area of deregulation and competition, along with technical progress to reduce transportation costs, can be expected to loosen some of the constraints and increase the international trade in gas.

V. TOWARDS THE EMERGENCE OF A GLOBAL GAS MARKET

In spite of the projected strong global demand for gas, the absence of a global market for the fuel has resulted in systematic inefficiencies, whereby excess gas supply in some (regional) markets exists side-by-side with shortages in some other markets. Chart 4 shows the effect of this phenomenon, as manifested by the relative prices of natural gas in the US and EU in the 1990s. The EU prices were higher than those in the United States in most of the years, with a sharp reversal of this relationship for a period of about a year starting around mid-2000 as the demand-supply balance in the US tightened in the wake of declining inventories, and the California energy crisis of the summer of 2000. American gas suppliers were unable to take advantage of the market opportunity presented by such price differentials (even after allowing for transportation costs) because of the absence of a global gas market. Similarly, European and Asian gas producers could not take advantage of the huge price differential when the gas price in the USA was more than double the European price for several months in 2000-2001. This can be explained in terms of the limited fungibility of natural gas due to the fact that most traded gas has a pre-determined destination/market, based on fixed long-term contracts.

The current industry expectation is that supply may exceed demand in the Asia-Pacific market in the medium term due to the volume of present and planned gas developments that are targeted at the region, which raises the specter of a depressed market in the area. At the same time, shortages are projected to occur in some other markets, particularly in the Atlantic Basin over the same period. The supply arrangements to the two markets are typically of a long-term nature, and are fixed in legal terms as well as by the supporting infrastructure. Changes in the supply-demand balance in one market may result in price spikes that persist for a long time (until corrected in that market), rather than through inter-regional volume flows.

The potential for the saturation of the Asia-Pacific market can be illustrated by the present race for sales contracts by several producers. As of now, three Middle Eastern countries—Oman, Qatar and the United Arab Emirates—already have a significant presence in the region, and are presently in search of further bankable customers in the area for planned new LNG trains, and the expansion and debottlenecking of existing plants. Meanwhile, gas producers in the region, including Australia, Brunei, Indonesia, and Malaysia are also planning capacity increases targeted at the same markets. With no new significant offtakers expected in the near future, these countries are now looking towards China and India where market opportunities are expected. However, the Chinese project (at Guangdong) is small, while there is uncertainty in some of the Indian projects due to delays, project scale-back, and questions about their overall viability. The *Petroleum Intelligence Weekly*—PIW—(November 27 2000) reports that as of late 2000, only one of the ten or more proposed Indian LNG schemes had secured financing. Meanwhile, newer producers, such as Iran and Yemen have initiated plans to build LNG plants, and have joined the search for clients in these markets as well. Yemen plans to build a 6.2-million tons per year LNG plant in 2001, with the Indian market as its main target, while Iran is reported to be planning a 15-million tons per year plant to come on stream in 2005.

The perception in industry circles is that some of the newer LNG projects in the Middle East region, for example, may not be following proper sequencing, and may be driven more by a desire *not* to be left behind by competitors, rather than rational economic planning. This, however, should not be a major source of concern, as investors in the sector will always be guided by the logic of the industry and adjust the scope and timing of their programs in the light of market developments. The securing of long-term SPAs, as a prerequisite for committing significant amounts of funds, is still the prevailing mode of operation in the gas business. Any uncertainty in this regard makes it more difficult to secure private financing. Thus, the policy challenge for gas producing countries is to synchronize their expansion programs with effective demand.

Unlike the situation in the oil market, where a spot market developed as an avenue through which market agents secured the marginal barrel or disposed of uncontracted volumes, a similar market has not emerged in the gas market (except in localized forms) due to the physical specificities related to the points of gas delivery.[15] For example, it is not possible to ship gas (by pipeline) to a particular destination just because there are market opportunities at that location; the transportation, storage, and other relevant infrastructure must already be present for that to happen. And if a producer is not already part of a gas system (e.g. with access to the pipeline network), such a party cannot participate effectively in the spot trade in that market. In the same vein, the futures market for natural gas is still developing, and its role limited. Banks (*op cit.*) has observed that since the inception of the NYMEX natural gas futures in 1990, "... sudden changes in the throughput, limited pipeline capacity, etc., have very often led to a pattern of spot and futures prices that have prevented the gas futures market from duplicating the efficiency of the oil futures market". However, some degree of market integration has been achieved in the European gas market, facilitated by increased pipeline interconnectivity, which, in turn, has increased spot trading activities.

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[15] The spot gas trade in North America is relatively more advanced and more liquid, owing to the larger number of participants and greater degree of market liberalization.

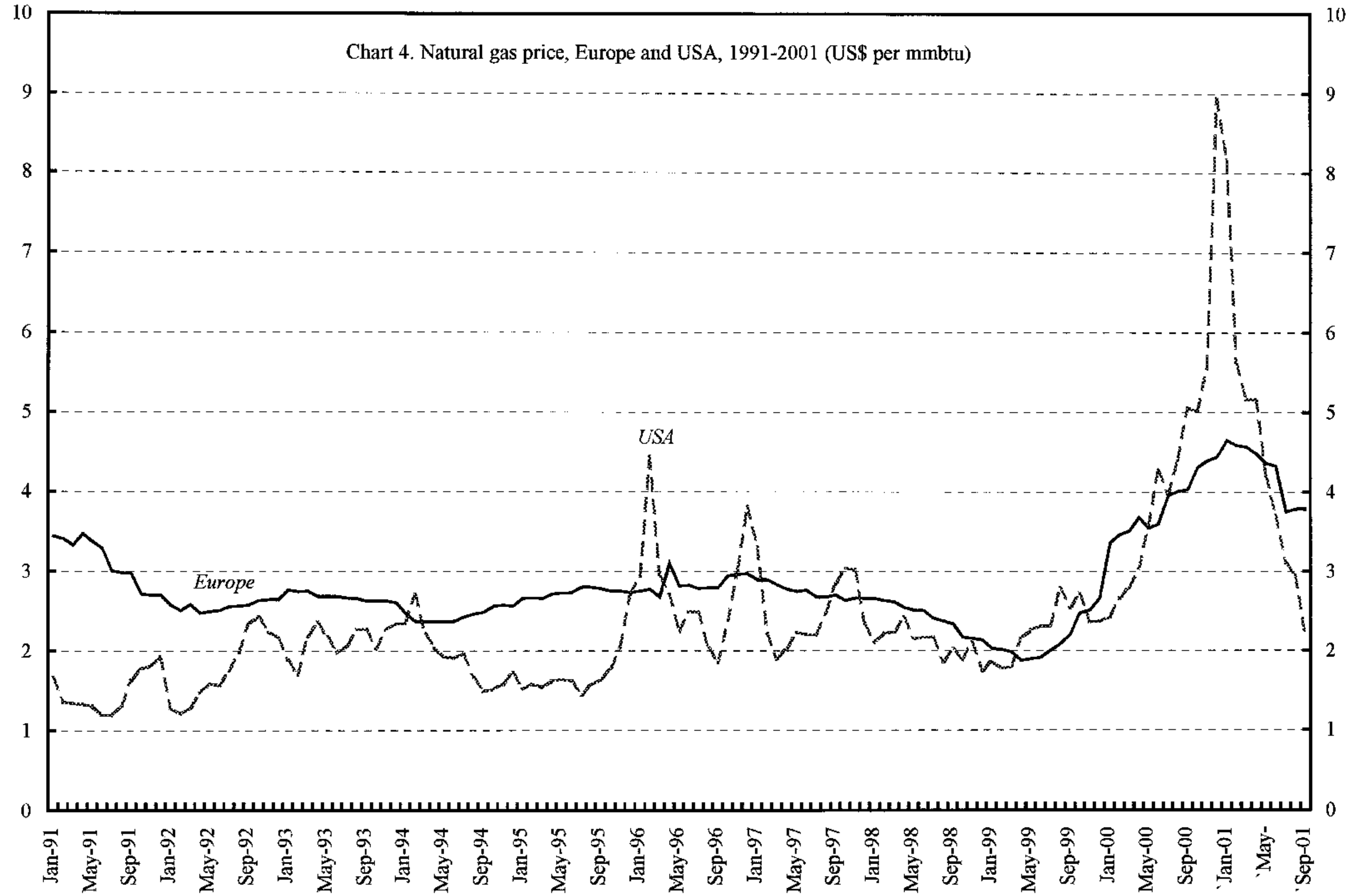

Chart 4. Natural gas price, Europe and USA, 1991-2001 (US$ per mmbtu)

Source: World Bank, Personal communication

Economic Rent and the Supply Price of Gas

There is increasing recognition in the gas market that the existing infrastructure assets are not being optimally utilized (see, for example, *Petroleum Economist*, May 2001), and this poses a challenge to the key players in the industry. Many LNG contracts involve transporting the gas over very long distances when the supply could be made by sources closer to that market. The problem has its roots in the very nature of the trade, which is carried out through long-term contracts, and the fact that contract prices are not always arrived at through a sufficiently open competitive bidding process. Like oil, there is a user cost (*UC*) and some element of rent, $R\varepsilon$, $(R\varepsilon > 0)$ in the gas price for many producers, especially the better-endowed countries with relatively lower production costs.[16] The user cost, which is commonly associated with exhaustible resources, can be viewed as compensation for the fact that a unit of gas produced today is no longer available to be produced in the future (Hotelling, 1931). The rent is defined as the difference between the price actually paid for a product and the minimum price necessary to supply it (see, e.g. Varian, 1990; and in specific reference to the oil market, see Okogu, 1996). The rent, $R\varepsilon$, may be written as:

$$R\varepsilon = P^* - (MCp + UC)$$

where P^* is the market price, MCp is the cost of production, and UC is the user cost.

In a perfectly competitive industry with an open bidding process, the contract price would be the same as the equilibrium price of a firm operating under perfect competition. Since bids are usually sealed, the optimal strategy for each producer would be to bid a supply price that gives him 'normal' profits. Assuming identical quality gas, production technology, and factor costs, resulting in identical production cost (C_1), the producer with the lowest shipping cost (C_2), would win the bid in an open competitive bidding arrangement. The optimum contract bid price would be one that maximizes his profit function (Π), i.e.

$$\underset{P}{Max}\ \Pi = R\text{-}C$$

$$= PQ - C_1Q - C_2Q$$

$$d\Pi/dQ = P - (C_1+C_2) = 0$$

$$P^* = C_1+C_2$$

P^* is the minimum risk-adjusted supply price necessary to ensure an adequate return on capital, and is what a profit-maximizing producer would bid in a competitive setting. Now, under an exhaustible resource model, with rent and user cost, profit maximization requires that provision be made for these two elements over and above normal profits, i.e.:

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[16] In principle, the user cost and rent could be collapsed into one item, simply referred to as economic rent, but we keep them separate because they represent different things.

$$\Pi - R\varepsilon - UC = R - C$$
$$= PQ - Q(C_1 + C_2)$$

Taking first order conditions, the profit-maximizing price would be:

$$P^* = C_1 + C_2 + R\varepsilon + UC$$

This equilibrium price is higher than that under perfect competition by the amount of the rent and user cost. The key feature of this price is that it contains a cushion, which alters the bidding behavior of the gas producer. The minimum risk-adjusted supply price that he would be willing to bid, under this model, is no longer P^*, but $P^* - R\varepsilon - UC$, with the rent and user cost providing a *negotiation* margin. With such cushion, and a relatively non-transparent contract bidding process, a gas supplier can afford to bid a lower supply price for contracts in distant markets (with high transportation costs) and still be profitable. In fact, as long as $0 < R\varepsilon + UC > C_2$, a producer has the incentive to try to increase his market share by undercutting lower cost competitors (those with lower transportation costs due to closer proximity to the market in question) in the contract bid and, in the process, tie down more tanker tonnage than optimal.

Rationalizing the Gas Business for Increased International Trade

A rationalization of the gas trade could involve a deliberate restructuring of the market to optimize the use of existing gas transportation infrastructure, which would harmonize gas prices across the main trading regions through increased inter-regional trade, and result in a more transparent process of bidding for new buyers between gas projects. The optimization strategy could involve rationalizing the regional trades such that *proximity* to the market plays a greater role in determining contracts. This would come about, not by *fiat*, but through more open competitive bidding for gas supply contracts that favor the least cost source (including transportation costs). In practical terms, this would mean that LNG from Asian producers would be the primary suppliers of Asian markets, while African and Middle Eastern producers (in addition to Europe-based producers) would serve the European market, and Trinidadian gas would go to the United States. Such an arrangement would release some shipping capacity that is presently 'wasted', for example, in the form of shipping LNG from Asia to North America, or from the Middle East to the Far East, etc.

The logic underlying this proposal is not far-fetched. Indeed, it is already in operation in the industry—in the pipeline segment of the gas trade. Of necessity, due to the physical constraint of the infrastructure and the dictates of cost minimization, the pipeline system has evolved according to the optimization principle. There are no pipelines running from South America to Europe, or from the Middle East to Asia-Pacific, for example, because it is not cost-effective! The present chaotic, albeit understandable, supply arrangements (geographically speaking) arose partly out of the long-term nature of SPA contracts: at the time of the agreements, either these were the only available supply sources with the capacity to meet the requirements of the buyers in question, or else, it was the result of non-transparent contract bidding process. This is not to trivialize the merit of free, long-distance trade, which, after all, is the hallmark of the international trading system. The proposal is motivated by the peculiar nature of the problem facing the gas trade, namely, the limited infrastructure.

It is recognized that such an optimization process can only be achieved with the main gas exporters and importers agreeing to such a change, which would take a major effort. In the interim, less tedious mechanisms based on market principles, such as asset swaps between pairs of exporters, could pretty much serve the same purpose. To illustrate the merit of this proposal, Trinidad in 1999, for example, exported 1.3 billion cubic meters (bcm) of LNG to the United States, and 0.75 bcm to Spain, while Qatar exported 0.60 bcm to the United States, and 0.84 bcm to Spain. An asset swap arrangement between these two countries (under which Trinidad would have supplied the US market with the total volume for both countries, and Qatar did the same for Spain), with minor adjustments for volume differences, would have resulted in substantial savings in shipping costs for both parties, and free up some shipping capacity in the process. There are other asset-swap opportunities of this type that could have produced similar benefits for the parties concerned (Table 2).

The freeing up of extra shipping capacity would encourage the growth of trade in uncontracted gas among the regions, especially where there is spare capacity. Countries would be less constrained in their capacity expansion plans since they can trade surplus volumes on the open (spot) market. This, in turn, would produce price convergence across regions, as producers would more easily move gas to take advantage of favorable price developments in other regions. Such a development would make contract prices more transparent and lead to standardization. Since most long-term contracts have renegotiation clauses, many of the existing SPAs could then be renegotiated to better reflect market developments. This would, in turn, make the process of bidding for sales contracts more transparent and efficient, and deliver price benefits for final consumers.[17]

Table 2. Liquefied Natural Gas Trade Movements, selected countries (1999) (Billion cubic meters)

	From								
To	USA	Trinidad	Qatar	UAE	Algeria	Australia	Brunei	Indonesia	Malaysia
North America									
USA	–	1.30	0.60	0.08	2.20	0.31	–	–	0.08
Europe									
Belgium	–	–	–	–	4.04	–	–	–	–
France	–	–	0.08	–	10.10	–	–	–	–
Italy	–	–	0.04	0.20	2.10	–	–	–	–
Spain	–	0.75	0.84	0.31	4.22	–	–	–	–
Turkey	–	–	–	–	3.10	–	–	–	–
Asia Pacific									
Japan	1.65	–	5.90	6.40	–	9.76	7.40	24.80	13.37
South Korea	–	–	0.67	0.08	–	–	1.01	11.36	4.40
Taiwan	–	–	–	–	–	–	–	2.65	2.70

Source: BP-Amoco, *Statistical Review of Energy*, 2000.

[17] At present, a lot of SPA negotiations tend to be opaque, with the terms of agreement often regarded as trade secrets by the parties.

VI. FACTORS DRIVING THE DEMAND FOR NATURAL GAS

As with other fuels, the demand for gas is driven by certain key factors: economic activity, its own price, the price of substitute fuels, and a vector of other factors, including environmental regulation and the weather. On the demand side, the desire for increased self-sufficiency in the major consuming countries, the need to diversify the fuel mix, and the imperatives of a cleaner environment along the lines of the Kyoto protocol are powerful drivers for a shift towards greater use of natural gas. Following the oil price shocks of 1973/74 and 1979/80, major oil consuming nations introduced a variety of measures to promote the use of domestic energy sources (including coal in the UK and Germany, and nuclear electricity as in France). The automobile industry continues to push ahead with new technologies such as hybrid-electric and fuel cell cars in an attempt to find an alternative for the petrol-based internal combustion engine. There has also been concerted effort to substitute away from oil to other fuels, including gas, through a policy of high taxation on petroleum products (Okogu, 1996; IEA, 1999), tax incentives for the development of alternative technology, increased R & D funding, and setting standards (e.g. emission standards for power plants and refineries).

Following the publication of the Brundtland Report (1987), and the *Earth Summit* in Brazil in 1992, there have been a series of meetings under the aegis of the *United Nations Framework Convention on Climate Change* (UNFCCC), which culminated in the adoption of the Kyoto Protocol of 1997 setting emission reduction targets (primarily for industrial countries).[18] The world's environment has come to be viewed as a global 'public good' that may not necessarily be used at an optimal rate because externalities are not internalized (see e.g. Baumol and Oates, 1988). International environmental policy in recent years has been geared toward reducing GHG emissions, including through policies to promote the substitution of gas for more carbon-intensive fuels. Gas has also continued to gain acceptance as an alternative to middle distillates in the domestic and commercial sectors, particularly in the OECD.

The demand for natural gas has also grown in connection with the requirements of the petrochemical industry, which relies on gas as feedstock to produce a variety of products, including ethanol, methanol, MTBE, ethylene, polyethylene, vinyl, ammonia, fertilizers, urea and sulfuric acid. These are used as raw materials in several industries, such as agriculture, pharmaceuticals, and textiles. Gas-rich countries, such as those in the Middle East, have used the opportunity of the availability of cheap natural gas to establish petrochemical companies in order to exploit their natural advantage in the fuel. In some cases, the motivation for gathering and processing the gas stems from a desire to use it as a substitute for oil in some domestic uses so as to free more (higher value) oil for export and for its convenience, as well as to avoid the default alternative of flaring, which pollutes the local environment.

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[18] See the special issue of the *Energy Journal* on the Kyoto Protocol (1999) edited by Weyant and Hill for a detailed discussion of the Protocol and related issues; and Mitchell (2000), for a more concise treatment of the key elements.

Empirical studies on gas demand are relatively few, and many are based on data up to the 1980s or earlier. Even newer research, such as Pesaran *et al* (1998) that studies the important Asian region, use data only up to 1990, and gas is very often grouped as part of other fuels. A more recent study (US EIA, 1999), has estimated the demand for natural gas in the United States for several sectors as part of its integrated short-term energy model, including household, commercial, and industrial sectors.[19] Monthly gas demand is modeled as a function of the weather (deviation from normal heating degree days), and seasonal dummy variables in all of these sectors. In addition, specific relevant variables were included in the equations: the commercial sector equation takes account of population, while for the industrial sector, gas-related industrial output was included. The price of gas (relative to that of residual fuel) was used as an argument only in the equation for the industrial sector, probably because this variable was found to be *not* significant in the other equations. In the residential sector, for example, the demand for natural gas is unlikely to be very responsive to changes in the price of the fuel in the short run because the capital investment for gas usage in homes is usually long term, which makes it difficult to switch to alternative fuels at short notice. The same argument applies to commercial establishments, but industries usually have more complex power systems, often with multiple fuel sources. Similarly, whereas output is certainly an appropriate variable for the commercial and industrial sector equations, the effect of income (or other proxy for output) on gas demand in the household sector is unlikely to be significant since the fuel is an essential good, the demand for which does not vary much with income levels. The generic form of the estimated equation may be represented as follows:

$$Dgi = Dgi(W\text{-}Wn,\ Pgi/Pci,\ Oi,\ Md)$$

where Dg is the demand for gas in sector i

$W\text{-}Wn$ is the percentage deviation of the number of heating days from the norm

Pg/Pc is the price of gas relative to the price of the competing fuel in sector i

O is the output of sector i

Md is a series of monthly dummy variables, with a value of 1 during the heating season, and zero otherwise.

As explained above, not all the variables are used for all sectors; all the coefficients are expected to have positive signs, except for the price variable.

Other studies, based on interfuel substitutions, provide both own and cross price elasticities of demand for gas vis-à-vis competing fuels in particular sectors (see, for example, Bacon, 1992, which summarizes the results of a number of such studies). A general form of the equation on interfuel competition casts the share of each fuel in total energy demand as a function of the proportion of that fuel in the total expenditure on energy and other determinants as follows:

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[19] Long term variables, such as autonomous energy efficiency improvement, demographic trends, etc., are not included in the equations.

$Dij/\Sigma Dij = Pij/\Sigma pijDij + f(\Phi)$

where *Dij* is the demand for fuel *i* in sector *j*

Pij is the price of fuel *i* in sector *j*

and Φ is a vector of all other relevant factors driving demand.

The demand for any particular fuel would be inversely related to its price relative to the price of competing fuels if they are substitutes, and directly if they are complements. An implicit assumption here is that there is perfect substitutability among the relevant fuels within the sector in question, which may not always be true, particularly in the short run. Some of the elasticity results from the literature are summarized in table 3. The own price elasticity obtained by Pindyck for the industrial sector of the USA is very close to that of Considine.

Table 3. Gas Demand Elasticities

	Own price elasticity (except USDOE, where weather elasticity is reported)					
	USDOE (weather elasticity)			Griffin	Pindyck	Considine
	Commercial	Industry	Household	Electricity	Industry	Industry
USA	0.003	0.18	0.005	-0.90	-0.52	-0.58
Japan	--	--	--	-2.40	-1.49	--
W. Germany	--	--	--	-0.80	-2.31	--
UK	--	--	--	-1.82	-1.38	--
OECD	--	--	--	-0.94	--	--
	Cross price elasticities					
	USDOE (industry)		Griffin (electricity)		Pindyck (industry)	
	Oil/Gas	Coal/Gas	Oil/Gas	Coal/Gas	Oil/Gas	Coal/Gas
USA	-0.47	--	0.53	0.16	-0.72	1.66
Japan	--	--	3.67	-0.07	-0.08	0.65
Germany	--	--	0.77	0.08	-0.18	0.43
UK	--	--	2.18	-0.03	-0.06	0.52
OECD	--	--	0.66	0.11	--	--

Sources: Bacon (1992); USDOE (1999).

Cross-country comparisons of own price elasticities in the electricity and industrial sectors show considerable dispersion, with gas demand in Japan and Germany, respectively, exhibiting the most sensitivity to price in these sectors. This may well be a reflection of the different firing technology in the countries; the scope for fuel switching is obviously greater in plants with dual firing than those based on a single fuel. The cross price elasticity results suggest that there is a strong degree of substitutability between oil and gas in the electricity generation sector, but a very weak degree of substitution between gas and coal in the same sector, or complementarity (since many countries have dual firing technology, using coal as base fuel and gas for peak load). On the other hand, oil and gas are weakly substitutable in the industrial sector (except in the USA), while coal and gas are strongly substitutable in the industrial sector.

VII. The Pricing of Natural Gas

The pricing of natural gas, under the long term SPA, is typically arrived at through a process of negotiation between the producer and the buyer—based on several factors—and the relative bargaining powers of both parties.[20] The main factors are summarized in Box 1. A gas-short country with little suitable alternative energy sources would be in a weaker bargaining position in an SPA negotiation compared to a better-endowed country. In this context, the relatively high price of Japanese LNG contracts is attributed in part to the greater need by the country to ensure security of supply due to a lack of indigenous energy resources (see, for example, World Bank, 2000). Similarly, a gas exporting country with a vulnerable pipeline network (e.g. due to civil war) would be weak compared to another country without such risks. A seller of LNG would, in most cases, have an edge vis-à-vis a potential buyer as compared to a pipeline-based gas seller in contract negotiations, *ceteris paribus*. Flexibility of delivery is generally greater with LNG than with pipelines, especially if they transit long distances or unstable territories, conferring the former with the image of being a "better quality" product than the latter. However, a stable political and legal environment, as in Europe and North America, reduces the perception of risk commonly associated with pipeline gas.

The price of gas would typically take account of the economic cost of producing the gas (including extraction cost, a user cost, and costs relating to externalities, etc.), as well as transmission and distribution costs. In addition to the above, the principle of gas pricing also seeks to relate the price of gas to its value in the individual end-user market for competing fuels. For example, the pricing formula under the SPA would usually link the gas price to the movement in the price of a competing fuel, including provision for periodic adjustments, to

[20] The outcome of the negotiations typically follows the two-party bargaining model with a non-unique outcome. The exact equilibrium depends on the relative bargaining strengths of the parties, including the ability to hold out and deploy bluffs and counter-bluffs. The fact that some of the key determining factors (see Box 1) are subjective in nature, and information about their state is usually incomplete, provides even more scope for such bargaining. For a concise exposition of the two-party bargaining model, see, for example, Layard and Walters (1978).

reflect changing conditions in the market for the competing fuel, and possibly also independent inter-temporal gas price escalations. It is usual to use the concept of "netback value", which is the maximum price of gas at the consuming market less all intermediate costs (regasification, transportation, liquefaction, etc.). At such a price, the buyer (usually a utility) is indifferent between using gas and other fuels as feedstock.[21]

A commonly used gas pricing formula, with minor variations, can be represented as follows:

$P_t = \beta + \pi K_{t-i} + \gamma P_{t-1}$
$i = 0, 1, 2, \ldots$(usually measured in months).

where P is the price of gas at time t;
β is a base price agreed at the outset;
π is the pass-through coefficient negotiated under the contract;
K is the price of the competing fuel at the agreed time, and may itself be linked to some international oil benchmark price;
γ is an intertemporal price escalation coefficient (γ=0, except in those periods when a price adjustment is made).

The above equation formulation encapsulates the basic issues underlying the gas market: (i) a recognition of the price risk inherent in the business, and the need to provide for the sharing of that risk between the buyer and seller under the SPA; (ii) provision for the price to track developments in the market for substitute fuels; (iii) provision for intertemporal price adjustment if and when considered necessary. With the base price and pass-through coefficient, the seller is protected against price swings below a predetermined level, while the purchaser benefits from the link between the gas price and that of the competing fuel.

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[21] See Siddayao (1997) for a detailed discussion of cost considerations as applicable to natural gas pricing.

Box 1: Factors affecting natural gas pricing provision

General situation of the country:
- Whether it is gas-short or gas-rich country
- Sharing of risk and chances
- Share of the gas compared with competing fuel
- Penetration strategy and penetration speed

The "quality" of the product
- Reliability of the gas
- Flexibility of deliveries
- Quality

Market conditions
- Which competing fuels?
- Shares of the competing fuels
- Changes of competing fuels over time or by price development
- Any premium may be subject to change in light of technical developments
- Changes in market structure (e.g. gas-to-gas competition)
- Changes in specific marketing costs due to changes in market structure (e.g. lo factor) or changes in sales volume.

Taxation

Source: *World Bank/ESMAP (1993)*

The pricing of LNG imported into Japan from Qatar illustrates the above principle:

$$PLNGt = 0.1485*JCCt + 1.0$$

$$JCCt = 2.2252145 + 0.95297774*QLCt$$

where in period t,
PLNG is the sale price of LNG into Japan;
JCC is the price of a cocktail of crude oils imported into Japan (the competing fuel);
QLC is based on the forecast price of the OPEC basket, which is highly correlated with JCC, as indicated by the high correlation coefficient.

The pass-through coefficient of 0.1485 (which is equivalent to using a conversion factor of 6.73 million BTU per barrel of oil) and the base price are the actual figures agreed between the parties. The price of the Qatar gas is on a *CIF* basis. The details of individual contracts may vary, for example, in terms of the level of the base price, but they generally follow the above principle. The Omani LNG agreement with Japanese buyers, for example, is on a *FOB* basis and uses a pass-through coefficient of 0.1515 (an implied conversion factor of 6.6 Mbtu per barrel of oil), but does not contain a fixed component or a minimum price.[22] Oman's *FOB* agreement means that it does not have to invest in shipping capacity to deliver its gas or even make the

[22] See Bartsch (1998).

means that it does not have to invest in shipping capacity to deliver its gas or even make the transportation arrangements through third parties, but this also robs it of the flexibility of placing extra volumes at short notice when they arise. Further, by not specifying a minimum price in the formula, investors in the Oman project fully assume the price risk below a certain level. The pricing of the European traded gas also follows the above general pattern, as it is typically tied to the price of Russian gas landed at the German border, which, in turn, is linked to the price of oil in European markets with some lag.

The determination of the natural gas price in the US has undergone significant changes since the early days when the industry was fully integrated, to the more recent era of "open access". In the earlier period, gas prices were arrived at either on the basis of market-determined netback calculations, or regulated wellhead prices plus intermediate costs (of transportation, handling, etc.). The present deregulated system has emerged, following a series of changes by the Federal Energy Regulatory Commission (FERC). The gas market is more competitive now than before, due to the regulation changes and the larger number of suppliers. The price of gas in the US is determined more on the basis of gas-on-gas competition than through indexation to the price of oil. In principle, this form of direct competition has the effect of driving the price down toward its cost of supply, which partly explains the lower cost of gas in the United States during most of the 1990s compared to Europe, for example.[23] Even with gas-on-gas competition, the price of gas is still related to that of oil, especially distillates, with which it is in direct competition in some uses (see Chart 5). An important factor in the behavior of gas prices relates to the developments regarding storage. Gas production in the United States plus imports are sufficient to satisfy domestic demand during most of the year, but not so during the winter season. The supply system therefore operates according to buffer stock rules under which gas is withdrawn from storage or built up throughout the year depending on demand levels. Hence the gas price has a direct relationship with storage levels and utilization rates (see Herbert *et al.*, 1997). Chart 5 shows the relationship between the prices of gas and oil in the major consuming markets—United States, Europe, and Japan.

The determination of gas prices in Europe is gradually beginning to look like that in the United States, with the emergence of gas-on-gas competition as the market has become more open in recent years. Similarly, the gas paper market has been growing, with a larger number of long-term contracts being tied to the price in this market. Spot trading activities remain sporadic, but growing as buyers increasingly look for flexibility rather than be tied down in long-term contracts, and sellers seek to dispose of uncommitted capacity.

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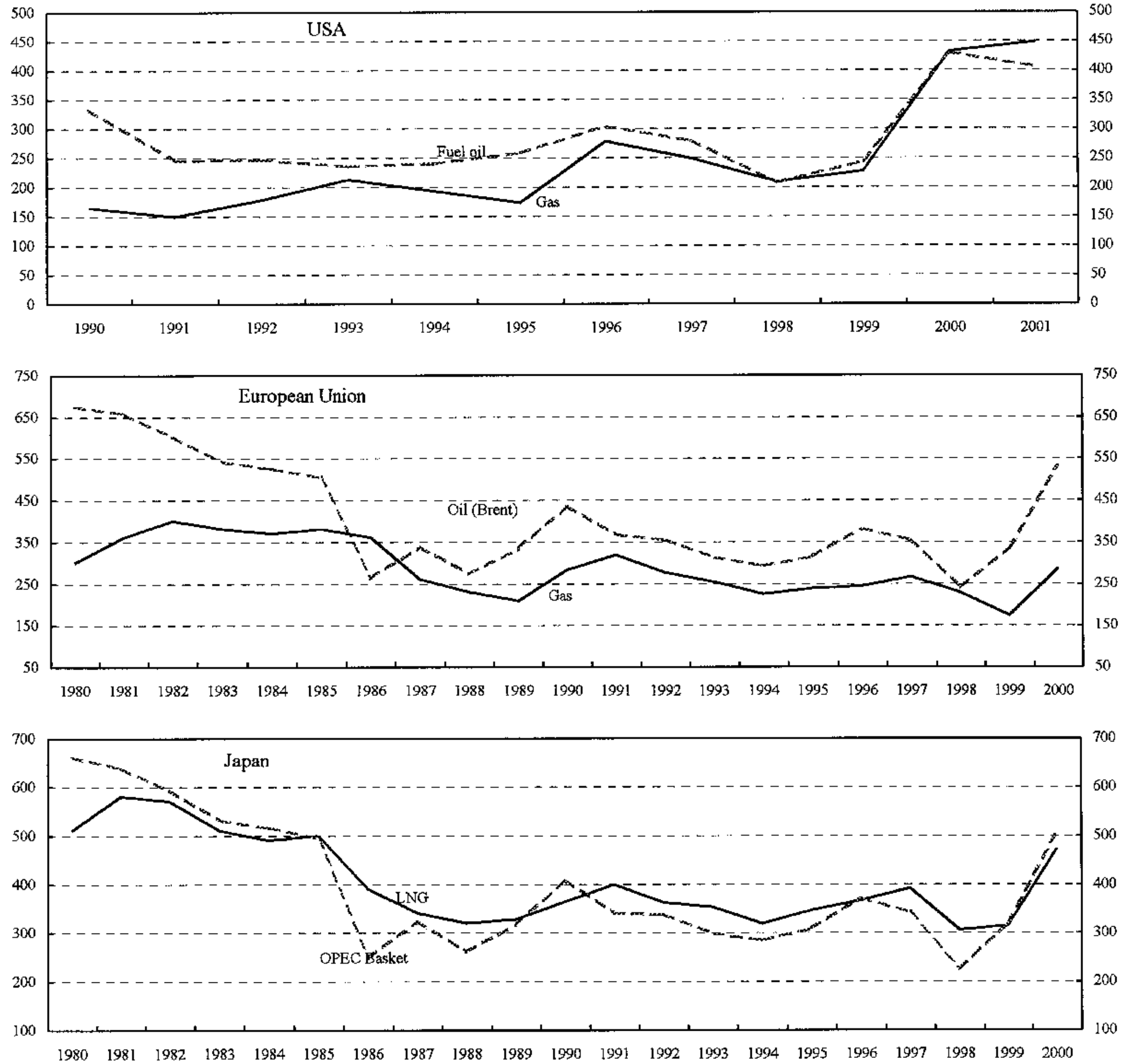
[23] In general, price regulation could achieve the same effect of driving down the price in the direction of the supply cost although at a slower pace than that based on the market.

Chart 5. Relationship between gas and oil prices: USA, EU, and Japan
(cents/mmbtu)



Sources: USDOE/EIA; BP Annual Statistical Review of Energy; OPEC

VIII. SUMMARY AND CONCLUSIONS

This paper has discussed various aspects of natural gas: its role in the global energy balance, factors constraining its development, and those preventing the emergence of a global market in the fuel. Further, evidence from the literature of the determinants of gas demand, the system of pricing, and the gas contracting process were analyzed. The share of natural gas in the global energy mix has risen significantly since the mid-1970s, and appears set for further acceleration in the years to come—driven by a variety of factors—including the need for greater energy security; a desire to take advantage of the availability of domestic reserves; and more recently, for its environmental advantages. Although the resource base is huge and more widely dispersed than oil across regions, the pace of development of the industry is constrained by the high cost of the specialized supporting infrastructure, and has left pockets of gas reserves 'stranded' in many countries.

The new wave of 'unbundling' the gas trading system in the US, Europe and elsewhere has increased competition, but a truly global gas market is yet to emerge, as the limited cross-border trade (at just 22 percent) is organized mostly on a regional basis, with very little interaction among the regional markets. The non-transparent nature of the gas contracting process, coupled with the presence of a significant element of rent in the price of gas for many exporters, has inadvertently led to a sub-optimal usage of the sector's limited infrastructure. The price cushion implied by the rent makes it possible for far away producers to outbid some short-haul competitors in a non-transparent contract setting, thereby tying down more tanker tonnage than necessary in long haul deliveries. A proposal for rationalizing the usage of the sector's shipping facilities through a strategy that optimizes the present trading arrangements is offered. This would not only cut costs but also release some shipping tonnage, open up the regional gas markets, help the development of a global gas trade in a more transparent international market, and eventually produce price convergence.

Evidence from the literature on the demand for gas is relatively scanty, but indicates a wide variation in the own and cross price elasticities of demand in different sectors. The variation is even more pronounced across countries, partly reflecting differences in resource endowments, energy policies, and firing technology in the relevant sectors (electricity generation, industry, etc.). At the level of long-term contracts, the price of natural gas is arrived at through negotiations between the parties, often without going through a rigorous competitive bidding process. The pricing generally tends to reflect several considerations, including the price of the closest substitute fuel, a negotiated pass-through coefficient, and an escalation clause to capture developments in the wider energy market. The contracting arrangement itself is typically done in such a way as to have complementarity in the distribution of risks and rewards across the various segments of the gas chain, with appropriate performance clauses, partly reflecting the inter-dependence of the different segments (see appendix).

APPENDIX

Gas contract negotiations

The sales and purchase contract is the cornerstone of any gas development project and, as such, is the subject of careful and intense negotiation between the relevant parties—the producer, the transporter, the purchaser, and possibly also the wholesale power purchasing companies. Best practice suggests that these various contracts be signed and implemented at the same time, as each component is essential for the success of the entire project. An LNG SPA, for example, is not complete until a secure arrangement for tanker transportation is made; a downstream purchaser of gas cannot be financially viable unless he has a reliable source of gas, and has secured sales outlets for the gas, which, in turn, depends on the existence of effective demand by final consumers, with an appropriate tariff system in place. The logic of simultaneous contract signing stems from the reality that the entire project can only be as strong as its weakest link. In addition to the main contracts, a terminal and pipeline operating agreement covering the handling of gas at the delivery port is also necessary in the case of LNG.

The purchase contract is entered into between the upstream producer and the buyer, with provision for a separate shipping contract if this module is owned by an entity different from the producer and purchaser.[24] This contract is typically long term (about 20 years or more) with adequate take-or-pay provisions for specified minimum and maximum takes. Given the large amount of money involved in gas projects, and the long-term nature of the sales and purchase contract, the producer would usually look for evidence that the purchasing company is financially strong and stable. The gas buyer, in turn, seeks to sign a fuel supply agreement with downstream gas users in order to guarantee an outlet for his gas. Depending on the power supply arrangement, the utility may also sign long term power purchase contracts with power distribution companies or final consumers to match its take-or-pay gas contract. In addition to the above, there are other contracts that need to be negotiated and signed at both the upstream and downstream segments of the chain, including construction contracts with clear completion dates, financing agreements, pipeline access agreements, port handling, etc. (chart 6).

As earlier noted, the gas industry originally operated largely as an integrated structure in many countries, with the various operational stages integrated into one organic whole.

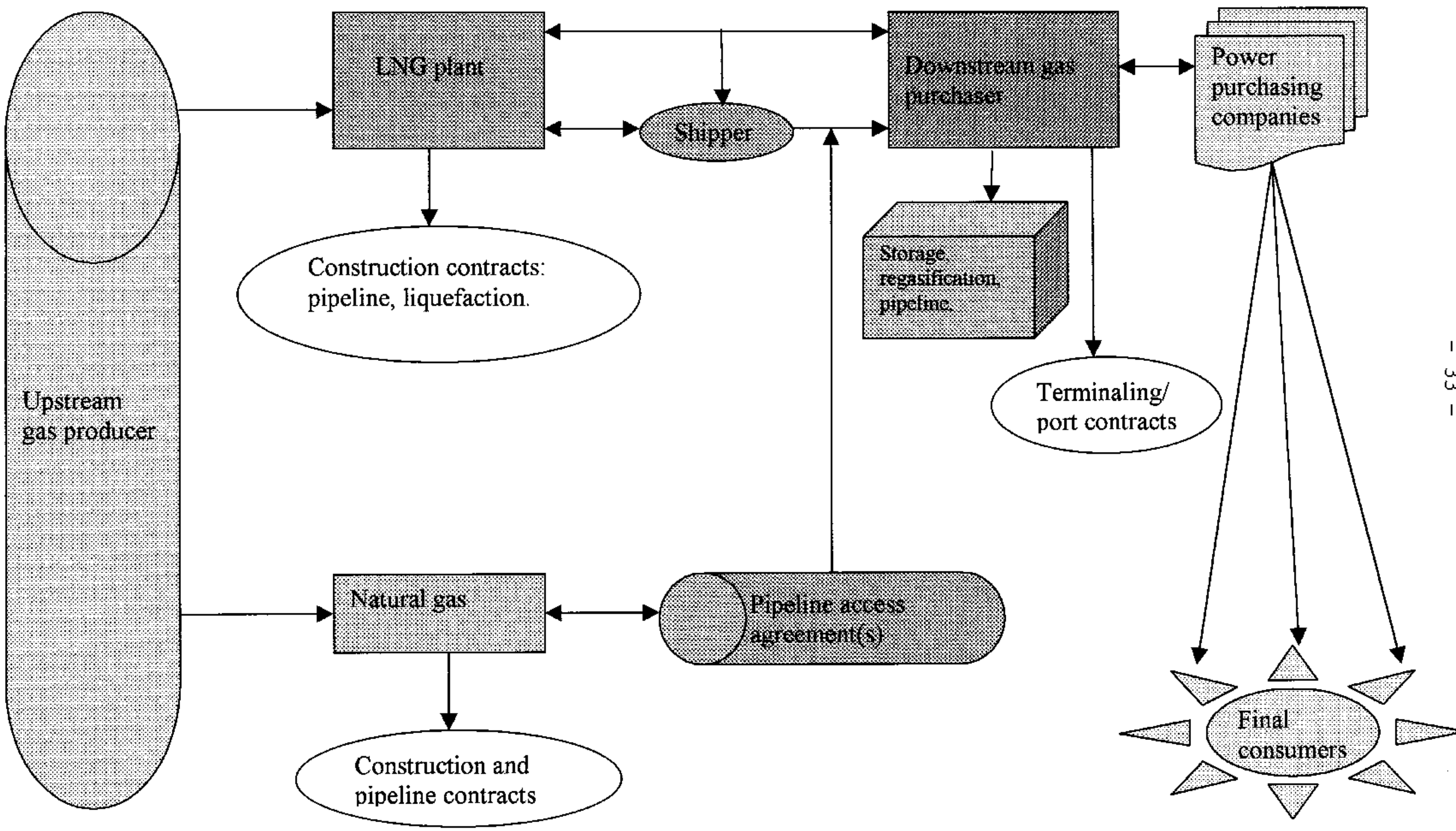
[24] It is often the case that the upstream gas producer would also purchase a fleet of tankers as part of the overall project investment; however, there are instances where this function is left to a third party. This latter situation clearly requires that a contract be signed between the tanker company on the one hand, and either the gas producer or purchaser on the other.

Such a system was more tenable in the context of a single country, and before the era of open access and competition. In the absence of centralized decision-making in the areas of production volumes, transportation, costing of ancillary services, marketing, etc., the performance of any segment of the gas chain is no longer dependent on the efforts of that segment alone, but on the actions of outside entities as well. Under such circumstances, investment decisions have to take account of the possibility that a complementary service provider may fail to perform, for reasons other than *force majeure*, even with a well-designed contract. Long-term contracts in the gas industry represent an alternative to the traditional model of vertical integration. It is an attempt to use legally binding agreements to replicate, as closely as possible, the characteristics of an integrated structure—particularly the assurance that the actions of the different segments of the operation are coordinated. However, even where contract enforceability is not a problem, there are still costs associated with the process. Hence, the contract approach is generally seen as a second best option. The contracts are usually arranged as a series of back-to-back agreements, designed to create links in the risk chain between the parties.

The provisions governing the contracts are usually such that risks are appropriately allocated across the various segments and that there is complementarity over the range of terms governing the agreements, such as contract duration, the base price, indexation, etc. In addition, as part of the imperative to have a financially viable company at the end of the chain, it is also necessary to have assurance that the regulatory regime in the downstream market is sufficiently flexible to allow the pass-through of costs and prices to final consumers as and when they arise. In this context, it is sometimes the case that the regulatory authority in the end-user market is required to approve the initial gas purchase contract, with special attention to the pricing and price escalation clauses. There is usually provision for independent arbitration in the event of disputes between the contracting parties—an option that is generally more attractive to participants because of the inherent tedium of a formal legal process, especially given the transnational character of these agreements.

The *QatarGas* contract example illustrates the process quite well. Incorporated in 1984, serious project planning began only in 1992 after *QatarGas* secured a long-term SPA with *Chubu Electric* of Japan to supply the latter with about 4 million tons of LNG per annum, with option of an additional 2 million tons (later exercised). It contracted an independent shipping consortium to transport the gas so as to minimize the initial investment cost. Chubu Electric had secured matching sales contracts with utilities in a growing Japanese power market, with a liberalized tariff structure that allows cost pass-through. The contracts underpinning the various segments of the chain were arranged in such a way that they were complementary with respect to risk, duration etc., as well as relevant take-or-pay clauses.

Chart 6. Schematic representation of the gas contract arrangement



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