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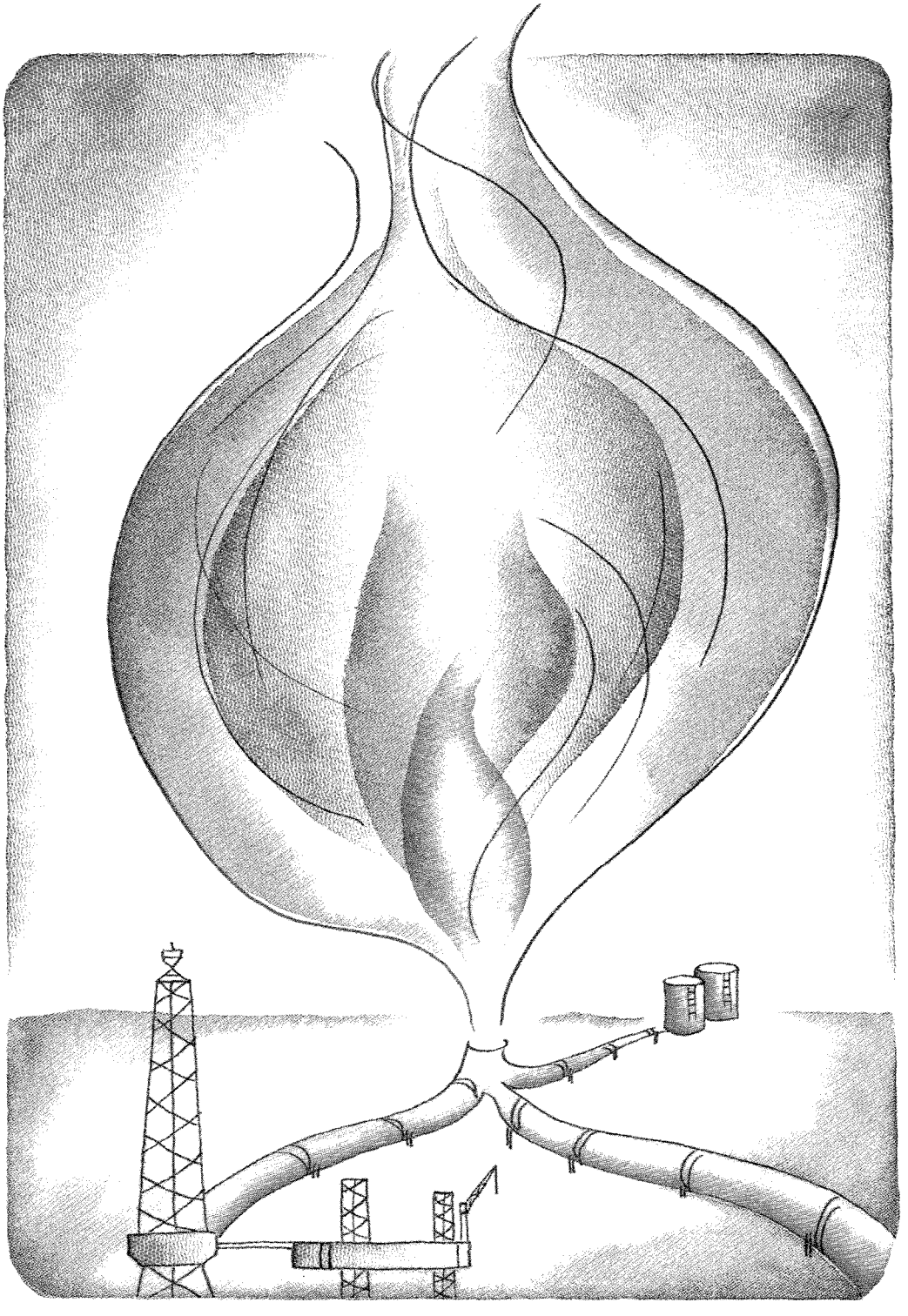

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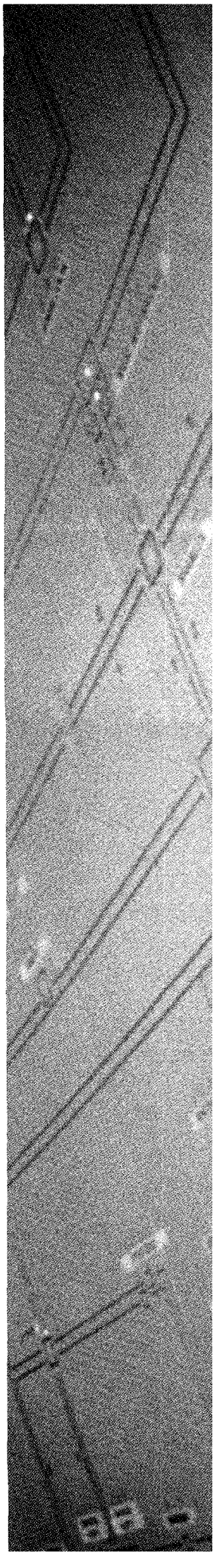

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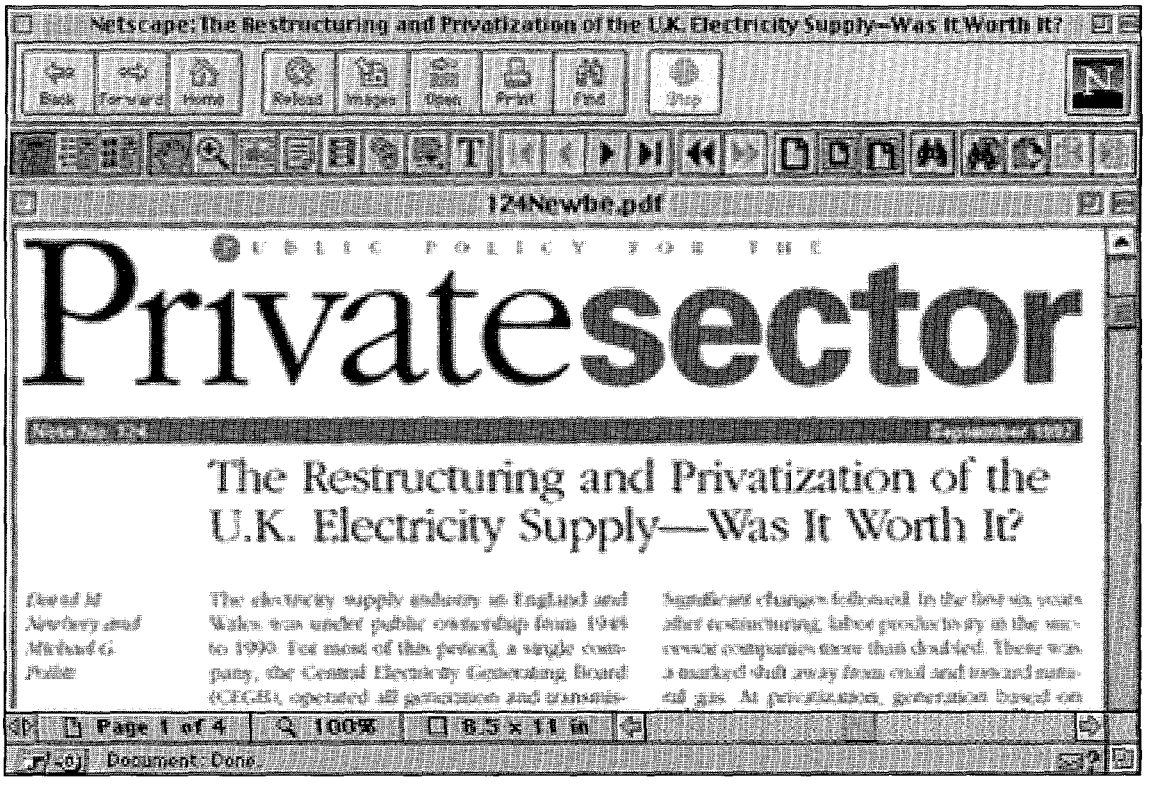

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Competition in the Natural Gas Industry

The emergence of spot, financial, and pipeline capacity markets

Andrej Juris

Countries in Asia, Europe, and North and South America are introducing reforms to boost efficiency and attract new private investment in their natural gas industries. The trend has been to unbundle along vertical and horizontal lines and to open wholesale gas markets to new entrants. These new entrants stimulate competition and the development of new markets in gas supply, in financial gas contracts, and in pipeline capacity. Such has been the success of these new markets—especially in the United States and the United Kingdom—that it has prompted a search for other potential markets in the industry. This Note, part of a broad effort to aid reformers by disseminating knowledge from early reforms, describes the underlying structural and trading arrangements in gas and pipeline markets. Two companion Notes examine these markets in the United Kingdom and the United States.

The emergence of gas and pipeline markets

Government control over gas companies and intervention in their operations and investment decisions have often led to distorted prices, inefficient operation, and deteriorating infrastructure. Thus reforms have aimed at limiting government's role in the industry's day-to-day operations and establishing an effective regulatory framework under which market forces would balance demand and supply in segments of the industry where competition is feasible. Only those segments where competition is not feasible would remain subject to economic regulation.

A traditional, vertically integrated gas industry typically has only one market, in which natural gas and transportation services are sold as a "bundle" to final consumers (figure 1). Introducing open access to pipeline transportation or unbundling supply from transportation creates two distinct markets: the gas market, where participants trade natural gas as a commodity and minimize price and supply risks, and the transportation market, where participants trade transportation services for shipping gas through the pipeline system (figures 2 and 3).

The increasing complexity of transactions in the gas and transportation markets calls for the use of intermediaries and for spot markets that promote efficient pricing and minimize transactions costs. Well-functioning spot markets concentrate trading in a central location where gas supplies and pipeline capacity are easily accessible. Spot market trading typically arises first in natural gas because of the viability of competition in the gas market. As deregulation of the gas industry continues, however, markets may also emerge in other segments, such as natural gas storage, metering and meter installation, pipeline construction, and system balancing.

But markets cannot be created in all segments of the gas industry, so reformers must consider

the viability of competition and markets in each segment separately. The market for natural gas has great potential for competitive supply and demand because economies of scale are relatively unimportant in natural gas production and trading. Multiple firms can operate in the market unless it is extremely small, and prices of natural gas can be freely determined by market forces. By contrast, the natural monopoly characteristics of pipeline transportation prevent efficient operation of multiple pipeline firms in the same market unless it is extremely large. As a result, tariffs for pipeline transportation must be subject to economic regulation to prevent an incumbent pipeline company from exploiting its market power.

The increasing complexity of transactions in gas and transportation markets calls for the use of intermediaries and for spot markets that promote efficient pricing and minimize transactions costs.

Well-functioning spot markets concentrate trading in a central location where gas supplies and pipeline capacity are easily accessible.

Both structural and regulatory changes have generally played an important part in reforms of the natural gas industry. In the United States, however, reform has focused on gradual regulatory changes, since the industry was already vertically unbundled. The government created a competitive wholesale gas market by deregulating wholesale gas prices and unbundling the supply of natural gas from transportation on interstate pipelines. And it promoted flexibility in pipeline transportation services by allowing resale of firm transportation contracts in a secondary market. Under way for more than ten years, deregulation has now shifted its attention to the retail gas market.

Gas reform in the United Kingdom involved both structural and regulatory changes, but in an inappropriate sequence. Gas supply to large consumers was liberalized and opened to competition in 1986, but the government failed to vertically unbundle British Gas, the former monopolistic gas company. Independent supply companies could not compete with British Gas, which controlled access to transportation and thus gas supply. Only after repeated regulatory interventions in the gas market in the early 1990s and an intricate separation of British Gas into two companies in 1996 could competition flourish in the wholesale gas market. Correcting the initial failure to decentralize the industry structure took ten years. But the new industry structure offers better conditions for liberalizing the retail gas market.

Argentina and several other countries in Latin America adopted a more radical approach to reform, vertically unbundling the industry and deregulating the wholesale gas market in one quick stroke. In these countries gas reform was part of a larger economic reform package to enhance efficiency and investment in all major infrastructure sectors.

The natural gas market

In the natural gas market, where natural gas is traded as a commodity separate from transportation services, participants typically trade natural gas under contracts. These contracts are of two main types, physical and financial, traded in different markets. The main participants in both the physical and the financial gas markets may include producers, traders, suppliers, pipeline companies, and distribution utilities, depending on the industry's degree of vertical and horizontal unbundling.

MARKETS IN THE NATURAL GAS INDUSTRY

FIGURE 1 VERTICALLY INTEGRATED NATURAL GAS INDUSTRY

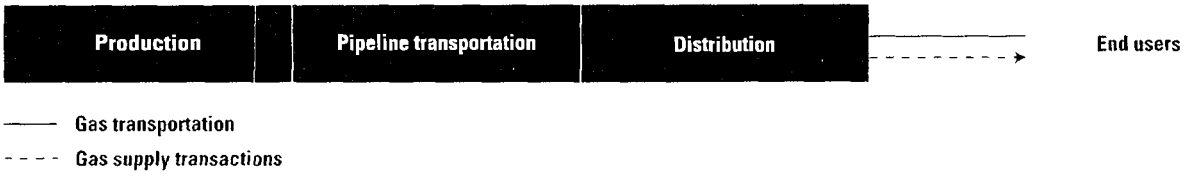


FIGURE 2 OPEN ACCESS AND WHOLESALE COMPETITION

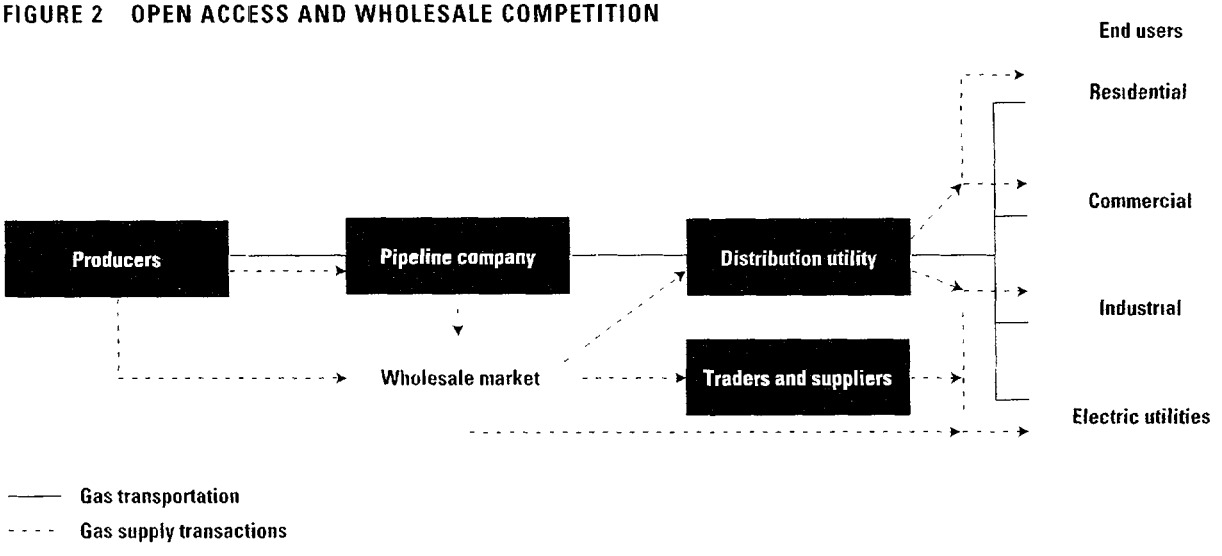
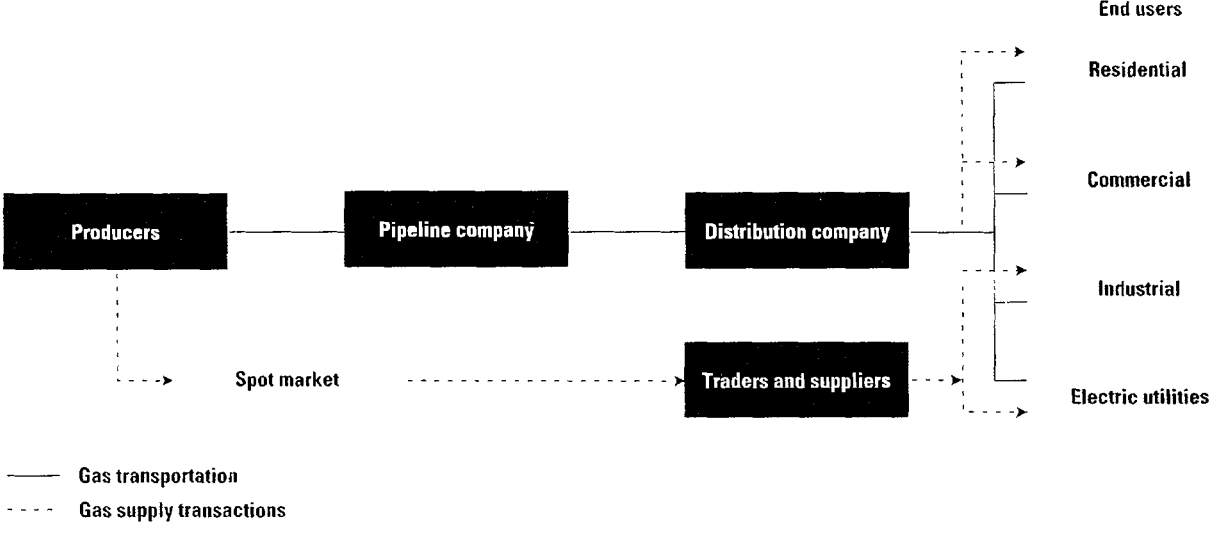


FIGURE 3 UNBUNDLED INDUSTRY AND RETAIL COMPETITION



The physical gas market

Participants in the physical gas market trade contracts for the physical delivery of natural gas—arrangements known as physical gas contracts (sometimes referred to as cash gas contracts). These contracts differ in two main dimensions, the purpose of the transaction and the duration of supply, and thus divide the physical gas market into several segments. A purchase of gas for resale takes place in the wholesale gas market, and a purchase for end use in the retail gas market. Wholesale transactions are concluded among producers, traders, suppliers, pipeline companies, and distribution firms, while retail transactions occur between suppliers and industrial or residential consumers.

Participants in spot markets, unable to predict future prices of gas, are exposed to price risk. Their need to minimize this risk leads to the development of a financial gas market.

Differences in the duration of gas supply divide gas contracts into three classes:

- Short-term gas contracts, for supply of up to one calendar month.
- Medium-term gas contracts, for supply of one to twelve months.
- Long-term gas contracts, for supply of more than one year.

Natural gas transactions were traditionally based on long-term supply contracts between integrated gas companies and their customers. Because these contracts fixed the price and volume of gas to be supplied over a specified period, they reduced supply and price risks. But they provided little flexibility to reflect the economic value of natural gas under changing market conditions. For example, the economic value of natural gas tends to be high during extremely cold weather, when gas supply and transportation capacity are generally constrained. If the contract price of natural gas is fixed, supply and demand do not adjust in response to the higher value. Demand may exceed supply, and gas shortages may occur. In such a situation demand must be rationed by administrative rules—an interruption of supply—rather than prices.

Deregulation of the gas industry and greater flexibility in natural gas supply change the importance of long-term supply contracts. Participants in deregulated gas markets need to balance their supply and demand in both the long and the short term so they can react to changing market conditions. Short-term balancing can be achieved by trading in the short-term (spot) market, where producers, traders, suppliers, distribution utilities, and large end users enter into daily trades. Spot market participants can acquire natural gas supplies relatively quickly and choose the time and quantity of supply based on needs and price. That flexibility allows them to form a portfolio of long- and short-term contracts that minimizes supply and price risks in both the long and the short run.

Spot markets typically develop where buyers and sellers are concentrated, such as at a pipeline interconnection near a large metropolitan area or at a major terminal in a gas-producing region. The Henry Hub in Louisiana and the Bacton terminal in the United Kingdom, for example, are both located at the entry point to a major pipeline network in a large producing region. By aggregating supply and demand, spot markets offer industry participants the benefits of high liquidity, intensive competition among buyers and sellers, and greater efficiency in the pricing of natural gas.

In a well-functioning spot market short-term (spot) prices reflect the economic value of natural gas. Gas industry participants use spot prices to value supply contract portfolios and make decisions about the size and timing of con-

sumption. Thus spot markets in natural gas serve the same function as other commodity or stock exchanges—they reveal the market value of the commodity traded. In the United States spot prices of natural gas at Henry Hub are a common indicator of market value.

Spot prices tend to be volatile, however, responding to changes in underlying factors of supply and demand such as the weather, available pipeline capacity, or consumption patterns. Participants in spot markets, unable to predict the future prices of natural gas, are exposed to price risk. Their demand for tools to minimize this price risk leads to the development of a financial gas market.

The financial gas market

The contracts traded in the financial gas market serve two main purposes: they minimize the price risk in the natural gas spot market, and they minimize the basis risk resulting from the changing price differential between physical and financial gas contracts. Financial gas contracts also serve as an instrument for speculation and price arbitrage in the gas market. They are seldom used for physical delivery of natural gas.

The most common financial gas contracts are forward contracts, swaps, futures, and options. Forward contracts and swaps are typically custom-tailored, with every aspect negotiated by the parties to the contract. Futures and options are standardized contracts typically traded in established commodity exchanges such as the New York Mercantile Exchange (Nymex) in the United States.

Transactions in the financial gas market involve the transfer of risks between market participants with different risk characteristics and risk management skills. For example, a distribution company with an obligation to serve final customers tends to be exposed to price risk because it cannot adjust its demand in response to changes in spot prices. Intermediaries such as traders or brokers tend to be experts in managing risk and can therefore better absorb the price risk. A transfer of price risk from the distribution utility to intermediaries minimizes the overall exposure to price risk and the costs of risk management.

A financial gas market will emerge in countries where the physical gas market has reached a certain level of maturity and a large share of natural gas is traded under short-term contracts. Since only a few countries have a mature spot market, the financial gas market is a relatively new concept. Only the United States and the United Kingdom have active financial gas markets today. Nymex, in the United States, developed and actively trades three natural gas futures and options contracts for delivery in three major spot markets in the United States and Canada. The International Petroleum Exchange, in London, trades a natural gas futures contract for delivery at the National Balancing Point, a notional balancing point in the pipeline system of BG (the pipeline transportation spin-off of British Gas). Financial gas markets are likely to emerge in other countries as deregulation continues.

Transactions in the financial gas market involve the transfer of risks between market participants with different risk characteristics and risk management skills.

The transportation market

Contracts traded in the transportation market cover transportation services—the supply of pipeline capacity and delivery of natural gas deliver to a desired location. Pipeline companies sell transportation contracts to shippers—any industry participants that want to move natural gas—in the primary transportation

market. In some instances holders of firm transportation contracts may resell them to other market participants in the secondary transportation market.

The primary transportation market

The contracts purchased by shippers in the primary transportation market give them the right to transport natural gas under specified conditions. The most important distinctions among transportation contracts are the duration and the reliability of the services provided. Contracts can be long, medium, or short term. And they can provide firm or interruptible service, a distinction that determines the priority given to a shipper during capacity shortages. Transportation contracts also specify the location, timing, and volume of natural gas shipments.

If transportation contracts establish transferable property rights to pipeline capacity, contract holders can trade the contracts freely and the secondary market can flourish.

The natural monopoly characteristics of pipeline transportation require that the primary transportation market be regulated to limit the market power of pipeline companies and promote efficient allocation of resources. A pipeline company must incur substantial fixed costs to construct the pipeline system before it can provide transportation services. These fixed costs dominate the company's cost structure because the variable costs of shipping natural gas through the system tend to be relatively low. Pipeline transportation exhibits economies of scope as well as scale. Once the pipeline is constructed, a company typically uses the same facilities to offer different transportation services.

Deregulation of natural gas markets creates a need for flexible transportation services. Market participants need to be able to match their gas supplies with transportation services. And they often require short-term balancing of natural gas supply and demand to optimize the cost and reliability of natural gas deliveries. They can achieve such balancing only if they can match their portfolio of gas supply contracts with a corresponding portfolio of transportation contracts. Thus pipeline companies need to offer medium- and short-term transportation contracts and flexibility in the choice of injection and delivery points. Such services are typically preceded by the development of a more flexible regulatory environment for pipeline companies and the creation of a secondary transportation market.

The secondary transportation market

Holders of unused firm transportation contracts can resell these contracts in the secondary transportation market. Buyers and sellers in this market may be almost any participant in the primary transportation market, though pipeline companies are excluded because of their market power.

Secondary transportation markets came into existence in the United States in 1992, when the Federal Energy Regulatory Commission introduced a capacity release program requiring interstate pipelines to allow holders of firm transportation contracts to release, or sell, any unused portions of their reserved pipeline capacity to other network users. The United Kingdom introduced a similar program of pipeline capacity resale in 1996 under the Network Code of British Gas.

The resale of transportation contracts promotes efficient allocation of transportation capacity. As a result of short-term changes in supply and demand, some pipeline users will not utilize all their contracted capacity, while others will lack capacity to ship their gas. In the absence of a secondary market holders of unused capacity cannot sell it to those who need it and pipeline capacity may go unused. A pipeline company

can use spare capacity for interruptible services, but efficiency may be compromised because interruptible tariffs tend to undervalue available capacity.

By contrast, the resale of firm transportation contracts allows contract holders to realize market value for unused pipeline capacity. Thus it can lead to optimal allocation of transportation capacity among market participants, based on their willingness to sell or pay. The efficiency of capacity allocation is sometimes constrained, however, by regulation of the resale price, which tends to be capped to reduce the potential for exercise of market power.

To promote efficiency in the secondary transportation market, it is important to assign property rights to transportation capacity to a large number of shippers. If transportation contracts establish transferable property rights to pipeline capacity, contract holders can trade the contracts freely and the secondary market can flourish. But if transportation contracts establish property rights that are not transferable, the resale of contracts is impossible unless it is intermediated by the pipeline company. Contract holders may still engage in side-dealing by using their spare capacity for delivery of third-party gas, but these deals often involve high transactions costs. Firm capacity contracts that give their holders the right to reserved pipeline capacity typically establish property rights. But the transferability of such contracts depends on prevailing regulation.

The resale of transportation contracts can take several forms. Auctions in which shippers bid by price can be used for trading both long- and short-term transportation contracts, although they may be too time-consuming for resale of short-term contracts. Transactions in which shippers mutually agree on the conditions for contract resale give the parties a great deal of flexibility and so are well suited for all types of transportation contracts. But this form of trading may be too costly for smaller and less informed participants that have to shop around for the best deal.

Short-term transportation contracts may be traded in a transportation spot market. To promote liquidity and efficient pricing in this market, transportation contracts need to be standardized in all important dimensions. The resale of short-term transportation contracts not only promotes efficient allocation of contracts, but it also facilitates the simultaneous clearing of gas and transportation markets by enabling market participants to match their spot gas transactions with short-term transportation contracts. Spot markets in transportation contracts are developing in the United States, where electronic systems for trading natural gas and transportation contracts link large numbers of buyers and sellers.

The services needed to support retail competition, such as metering and billing, are also targets for the introduction of competitive provision.

Active trading of short-term transportation contracts will eventually give rise to a financial transportation market where participants can minimize the price risks in the physical market.

Market prospects

Having achieved considerable success in wholesale market competition, the United Kingdom and the United States are moving toward competition in retail gas supply to small consumers, under arrangements that will allow consumers to choose among gas suppliers and reap efficiency gains like those in the competitive

wholesale gas market. The services needed to support retail competition, such as metering and billing, are also targets for the introduction of competitive provision. The unbundling of pipeline transportation has led to marketlike operation of natural gas storage facilities, with storage operators taking advantage of seasonal and daily price variations in nearby spot markets. Active trading of short-term transportation contracts will eventually give rise to a financial transportation market in which participants can minimize the price risks in the physical transportation market. And with continued advances in technology and in the understanding of how the natural gas industry operates, more opportunities for competitive provision of goods and services will surely emerge.

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Natural Gas Markets in the United Kingdom

Competition, industry structure, and market power of the incumbent

Andrej Juris

Deregulation of the U.K. natural gas industry has facilitated new entry and competition in almost all segments of the industry except pipeline transportation. The new regulatory framework, developed largely by the Office of Gas Regulation (Ofgas), has allowed market forces to stimulate a variety of specialized services and market transactions to meet customer needs. But deregulation has been difficult because of a flaw in the initial industry structure: the government privatized British Gas as a vertically integrated company. The U.K. experience shows that leaving gas supply integrated with pipeline transportation and tying up gas in long-term contracts impede competition. This Note reviews the U.K. reform and the development of new spot, on-system, and "Flexibility Mechanism" markets.

Structural problems

Until 1986 British Gas operated as the publicly owned, vertically integrated transporter and supplier of natural gas in the United Kingdom. Only gas production was open to competition, and this segment was dominated by multinational oil companies. In 1986 the government privatized British Gas, choosing to leave it a single, vertically integrated company in order to speed the transaction and maximize the sale proceeds. At the same time it separated the gas market into three major segments:

- The wholesale market, where gas is traded between producers, traders, British Gas, and independent suppliers.
- The contract market, where gas is supplied to large consumers (initially those consuming more than 25,000 therms a year, now those consuming more than 2,500 therms a year) by British Gas or independent suppliers.
- The tariff market, where gas is supplied to small consumers (those with annual consumption below the threshold for large consumers) by British Gas.

The government opened the wholesale and contract gas markets to promote efficiency and lessen the dominance of British Gas. It permitted large consumers to contract for natural gas directly with producers. And it allowed independent gas shippers, traders, and suppliers to arrange gas supplies for large consumers in order to create competition in wholesale supply.[1] The tariff market remained closed to competition, and British Gas continued to be the sole supplier of natural gas to small consumers. The government believed, rightly at the time, that competition in gas supply to small consumers was not economically feasible. Wholesale and contract gas prices were liberalized, while Ofgas regulated retail tariffs to protect consumers from the market power of British Gas.

The decision not to unbundle British Gas in 1986 hindered the development of a competitive gas market. Because British Gas controlled the entire pipeline system and held long-term gas supply contracts with producers, it was able to retain a de facto monopoly in the wholesale

and contract gas markets and control entry by independent gas suppliers. In an attempt to improve access to gas supplies and transportation, Ofgas introduced the 90:10 rule in 1989, which prohibited British Gas from contracting more than 90 percent of gas deliveries from any field on the U.K. continental shelf. The 90:10 rule effectively forced producers to market their gas to independent suppliers, promoting the development of wholesale gas trading at the "beach," the entry terminals of the British Gas pipeline system.

The 90:10 rule did not, however, remove the main source of the problem: the ability of British Gas to control access to its pipeline network. Complaints about the company's market power prompted another set of regulatory measures in the early 1990s, when Ofgas asked British Gas to release more natural gas to independent suppliers and to build "Chinese walls" separating its gas supply and pipeline transportation businesses. The intention was to increase independent suppliers' access to natural gas from producers and to level the playing field for suppliers contracting for pipeline transportation.

Between late 1993 and mid-1996, when regulatory disputes were intense, the market value of British Gas's assets fell by half.

British Gas complied by selling about 5 billion cubic meters of natural gas (roughly 3 percent of the total gas supply) to independent suppliers and by creating two divisions, British Gas Energy and British Gas TransCo. But the prospect of further regulatory intervention on liberalization of the retail gas market led the company to seek more permanent structural change. In 1996 it decided to split its assets into two companies: Centrica, a gas production, sales, and supply business, and BG plc, a transportation and storage business. This separation, or "demerger," of British Gas was completed in 1997.

The demerger finally corrected the government's failure to restructure the industry at the time of privatization. The costs of the failure had been significant. The industry's flawed structure resulted in frequent regulatory interventions in the markets and disputes between Ofgas and British Gas. This increased the regulatory risk and cost of capital for British Gas, which saw a big drop in the market value of its assets. Between the fall of 1993 and mid-1996, when the disputes were particularly intense, the market value of the assets fell by half—from £15.5 billion to £7.7 billion. And the demerger itself was a costly exercise, with the company paying millions of pounds in accounting and legal fees.

The U.K. experience shows that if a single company controls access to gas supplies and transportation capacity, as British Gas did, competition may be inhibited. Simply removing administrative barriers to entry in gas supply and deregulating gas prices are not enough to ensure competitive gas markets. A move from monopolized to truly competitive gas markets requires structural and regulatory changes that protect new entrants from the market power of the incumbent. It took almost a decade to remedy the failure to unbundle British Gas before its privatization. Only after U.K. regulatory authorities intervened in the acquisition of natural gas from producers and the incumbent's operation of the pipeline network could real competition emerge in natural gas supply.

New markets

Competition has fostered new ways of trading natural gas, reflecting market participants' need for more flexible gas supply arrangements. Spot markets have formed at major terminals, allowing market participants to balance their short-term supply and demand by trading natural gas. As a result of new pipeline operating rules, a flourishing spot market has developed within the pipeline system. The pipeline operator also

uses market pricing to determine the costs of balancing supply and demand over the pipeline network.

While natural gas markets are substantially deregulated, gas transportation remains heavily regulated because of the natural monopoly characteristics of pipeline transportation. British Gas—followed by its transportation spin-off, BG—has remained the single operator of the U.K. pipeline system, and transportation charges are regulated. The secondary transportation market is just beginning to emerge, with resale of pipeline capacity among shippers allowed only since 1996.

As markets for wholesale (and, increasingly, retail) gas supply have become more competitive, the quantity and quality of services available to market participants have improved, and consumers have benefited from declining real prices for natural gas even as consumption has been increasing. Residential prices fell by 24 percent in real terms between 1986 and 1995, and industrial prices by 47 percent. During the same period consumption increased by 38 percent.[2] Deregulation of wholesale and contract markets has attracted more than forty suppliers, all competing fiercely. The increased competition in the contract market is reflected in the diminishing market share of British Gas, which fell from 80 percent in 1992 to 33 percent by the end of 1996. The industry operates much more efficiently than it did before 1986, and consumers have been able to benefit.

Market dynamics

The trading and contracting of natural gas in the United Kingdom have changed dramatically since the privatization of British Gas in 1986. Traditionally, most natural gas was sold under long- and medium-term contracts between producers and British Gas at the wholesale level and between British Gas and consumers at the retail level. After the contract market was liberalized in 1986, long-term contracting became insufficient to meet the needs of the growing number of participants in the wholesale and contract gas markets. Independent suppliers and large consumers demanded contractual and supply flexibility to allow them to efficiently balance their short-term supply and demand. Independent suppliers also sought a trading location that would give them unrestricted access to gas deliveries, outside the control of British Gas.

Aided by regulatory measures, the market response to the demand for greater flexibility and better location was the development of spot markets. First, wholesale gas trading moved to the "beach." Here natural gas supply from more than forty producers promised sufficient availability of natural gas and flexibility in delivery conditions. Second, the concentration of trading at entry terminals promoted the development of spot markets, where natural gas is continuously traded. More trading opportunities were created when British Gas separated its gas supply and pipeline transportation operations. The introduction of the British Gas Network Code in 1996, which set out the rights and responsibilities of users of BG's pipeline network, created two additional gas markets within the pipeline system of British Gas.

The on-system market has become increasingly popular among shippers because of its central location, accessibility, and low transactions costs.

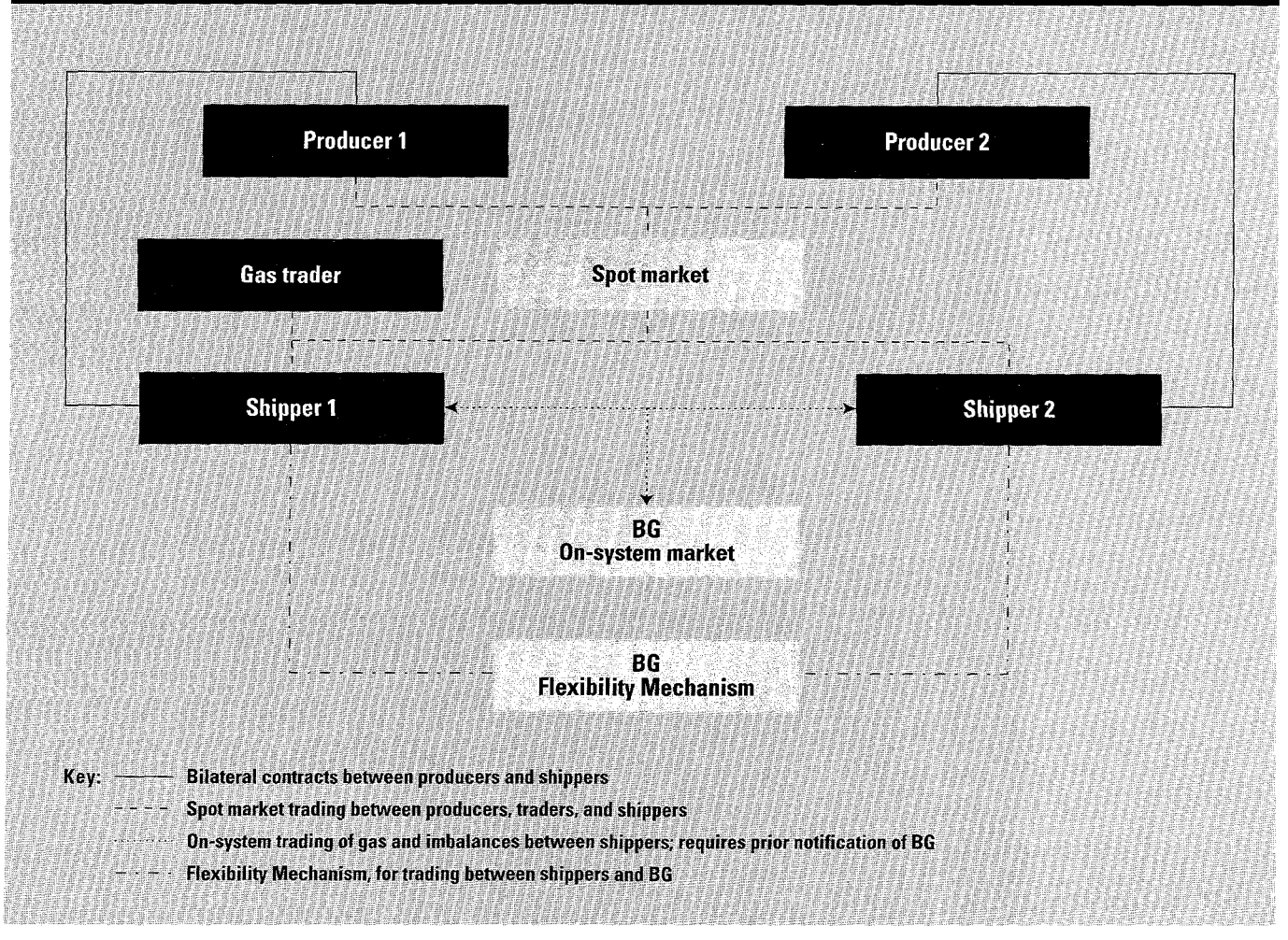
Participants in the U.K. gas market now use four mechanisms for trading natural gas (figure 1):

- Bilateral contracts.
- Spot markets.
- The on-system market.
- The Flexibility Mechanism.

Bilateral contracts

Bilateral contracts are the traditional form for trading natural gas in the United Kingdom. Until

FIGURE 1 MECHANISMS FOR NATURAL GAS TRADING IN THE UNITED KINGDOM



privatization British Gas typically concluded long-term take-or-pay, or "depletion," contracts under which British Gas covered a share of the financing of a producer's field development cost in exchange for assured future gas deliveries.

The opening of natural gas supply to competition, however, has introduced new contractual relations in the gas market as producers and independent suppliers look for ways to achieve greater supply and price flexibility. This has spurred the development of a wide range of long-, medium-, and short-term supply contracts with delivery provisions to meet specific demand and supply characteristics of contracting parties.

Such a move is not without costs, however. The opening of the gas market to competition exposed British Gas to transition costs, in the form of net liabilities resulting from overcontracting. In 1996 the company held take-or-pay obligations to purchase about 4.6 billion cubic feet of gas a day (bcfd) from producers over the next five years, while gas sales were projected at 4.35 bcfd, on the assumption that BG would maintain a 90 percent share

in the tariff market in 1998. That resulted in an estimated surplus of 0.25 bcfd, or 5 percent of take-or-pay obligations, with a value of £528 million.[3] Although this surplus is not a significant volume, it represented almost 30 percent of spot market sales in 1996. Thus if BG delivered its surplus gas to spot markets, it would drive down spot market prices and potentially harm its position in the retail gas market. In any event, the losses have probably been mitigated by delays in the introduction of retail competition.

Spot markets

Spot market trading has developed with the opening of natural gas supply to competition. As the large number of contractual relations between producers and suppliers made it infeasible to always negotiate all aspects of supply contracts, demand arose for the standardized contracts suited for spot market trading. Another factor in the development of spot market trading has been the gradual shift in natural gas transactions to locations where producers and suppliers can rely on standardized delivery conditions and have the best access to the pipeline system.

Natural gas spot markets have developed at six onshore terminals of the British Gas pipeline network, where the concentration of producers' gathering pipelines and the transportation pipelines of British Gas promised good availability of both gas supplies and transportation capacity. The spot markets enable participants to balance their supply and demand in the short term by buying or selling natural gas in one or more central delivery locations. The high volume of natural gas trading in the spot market has led to greater standardization in supply conditions, such as in the duration of delivery, and thus in gas supply contracts. This standardization of contracts promotes market liquidity and efficiency in spot gas prices.

Spot market gas trading in the United Kingdom is bilateral, involving producers and shippers, or on a brokerage basis, with traders often acting as intermediaries. Spot trading started in 1989–90 as a bilateral telephone market between producers and independent suppliers, but trade volumes were low because most producers' gas supply was contracted by British Gas. Over time there has been a large increase in volume and in the number of traders.

The most active spot markets are at the Bacton and St. Fergus terminals, which are well connected with large producer and consumer areas. The most common contracts traded in these markets are day-ahead and monthly gas contracts, specifying delivery on the next day and in the coming month. Other contracts traded in spot markets include:

- Balance gas contracts, for delivery in the rest of the current month.
- Quarterly and annual gas contracts, for delivery in a specific quarter or year.
- Time spread contracts, for the exchange of contracts with different delivery periods.

The strong prospects of the on-system market and its potential for efficient pricing of physical gas contracts have led the International Petroleum Exchange in London to develop its first natural gas futures contract.

Despite the increasing volume of gas traded in spot markets, trading remains relatively thin and illiquid. In 1996 trading volumes at Bacton ranged from 2 million to 8 million therms a day, only 5 to 10 percent of the total daily supply. Prices at the terminal varied accordingly—from 9 pence to 14 pence a therm. The U.K. gas market appears to be too small to support efficient functioning of five to six spot markets. Perhaps a more central location is needed

where most of the country's natural gas supplies could be traded. British Gas, inspired by the growing use of natural gas spot trading, introduced a central location within its pipeline system when it launched its on-system market in 1996.

The on-system market

The on-system market is basically a natural gas spot market with the delivery point at the National Balancing Point (NBP), a notional point in BG's pipeline network at which BG balances its high-pressure pipeline system. In effect, all gas supplies transported through BG's high-pressure pipelines can be traded at the NBP.

A transaction in the on-system market typically involves shippers that own transportation contracts and are willing to sell or purchase natural gas. Selling shippers use their reserved pipeline capacity to deliver natural gas to the NBP, where they sell it to interested buyers.

The Flexibility Mechanism allows market-based determination of the value of the natural gas needed to restore balance in BG's pipeline system.

Buying shippers then use their pipeline capacity to transport the gas from the NBP to the desired location. Transactions are facilitated by BG, which keeps track of traded volumes and provides transportation services.

The on-system market has become increasingly popular among shippers because of its central location, accessibility, and low transactions costs. The whole range of natural gas contracts, much the same as those traded in a spot market, are traded daily in the on-system market. Traded volumes in the on-system market, and possibly in other spot markets, are likely to increase as the share of Centrica (the British Gas supply and trading spin-off) in the liberalized retail market diminishes and more gas becomes available from producers as a result.

The strong prospects of the on-system market and its potential for efficient pricing of physical gas contracts have led the International Petroleum Exchange (IPE) in London to develop its first natural gas futures contract based on delivery at the National Balancing Point. The introduction of the IPE Natural Gas NBP contract on January 31, 1997, marked the beginning of financial gas trading in the United Kingdom and in Europe. The contract has found broad acceptance among gas traders because of its central delivery location and smooth administration. By July 31, 1997, the volume traded under such contracts had reached almost 30 million therms, equal to about 40 percent of the United Kingdom's daily production of natural gas.

BG's Network Code requires all shippers to balance their gas shipments through the pipeline system—that is, to maintain their injections and withdrawals of natural gas below a specified tolerance level—on both a daily and a monthly basis. Shippers can balance their shipments by buying or selling natural gas in the highly liquid on-system market, where the price of natural gas determines the cost of maintaining their balance. But shippers do not always maintain their daily balance, and the whole pipeline system may become unbalanced if the sum of individual imbalances exceeds a certain tolerance level. The pipeline operator must then inject or withdraw natural gas to restore the balance in the pipeline system. The value of the natural gas in these transactions is not reflected in the on-system price, because BG cannot participate in on-system trading. To facilitate the pricing of this gas, British Gas introduced the Flexibility Mechanism in 1996.

The Flexibility Mechanism

The Flexibility Mechanism allows market-based determination of the value of the natural gas needed to restore balance in BG's pipeline system. BG trades this natural gas in an auction.

Interested shippers post their bids, specifying volumes and the prices at which they want to buy or sell, on an electronic network. BG buys natural gas if it expects that injections into the system will be less than withdrawals, and sells natural gas if it expects the reverse. BG accepts the bids that cover the expected system imbalance and that either minimize the cost of buying natural gas or maximize the revenue from selling it. The price of the last accepted bid determines the system marginal price at which transactions between BG and shippers are concluded. BG solicits bids from shippers daily, so that they are always available.

As in any auction, competition among shippers promotes efficient pricing of natural gas traded under the Flexibility Mechanism. If shippers want to ensure that BG accepts their bids, they will reveal their true willingness to buy or sell natural gas. BG can construct a market (supply and demand) from shippers' bids, and decide which ones minimize the cost of restoring system balance. Since the last accepted bid determines the price for all transactions, the system marginal price reflects the economic value of natural gas needed to restore balance in BG's pipeline system.

The cost of restoring system balance under the Flexibility Mechanism is recovered from the shippers that cause the imbalance. Undisciplined shippers must either pay the system marginal price for the natural gas below the tolerance level of their shipments or accept the system marginal price for natural gas that is above the tolerance level. Since the system marginal price is typically higher than the price of natural gas sold or lower than the price of natural gas purchased in the spot market, undisciplined shippers experience losses on their imbalances in addition to any imbalance penalties imposed by BG. These potential losses deter shippers from violating the balancing rules of the Network Code.

Conclusion

The U.K. experience shows that the development of competitive natural gas markets must be supported by an appropriate industry structure and regulation to protect new entrants from the market power of the incumbent. To promote competition, the liberalization of entry to gas supply and of gas prices must be accompanied by open access to gas supplies from producers and to transportation capacity for delivering natural gas to consumers. The practices of tying up natural gas in long-term supply contracts and integrating gas supply with pipeline transportation must be eliminated to enable independent suppliers to acquire natural gas in the wholesale market, gain equal access to pipelines, and start to compete on equal footing with the incumbent gas company.

It is important to introduce structural changes at the beginning of the reform to set the stage for developing markets and competition later in the reform.

Developing competitive natural gas markets can require frequent regulatory changes and interventions, as it did in the United Kingdom. But these interventions can lead to many controversies and disputes among industry participants and between the industry and the regulator, often with harmful effects for both companies and consumers. The cost of increased regulatory risk and the risk of political intervention discourage investment in the gas sector. So it is important to introduce structural changes at the beginning of the reform to set the stage for developing markets and competition later in the reform.

Market forces have proved to be vital and effective in the gas industry, once appropriate structural and regulatory measures establish some breathing room. New entrants in gas trading, shipping, and supply can emerge overnight and introduce new methods of transacting business, such as spot market trading. By

concentrating trading in one location, spot markets like the U.K. on-system market can fill a vital role for market participants that require flexibility in gas supply and efficient pricing of natural gas. And spot market pricing of natural gas can be used for valuation of system balancing, as it is in the Flexibility Mechanism of BG.

[1] Categories of market participants are defined in the Network Code of BG plc, the pipeline transportation spin-off of British Gas. Shippers are firms with shipper licenses that buy gas from producers, sell it to suppliers, and contract with BG to transport the gas to consumers. Suppliers are firms with supplier licenses that buy gas from shippers and sell it to consumers. They do not deal directly with producers or BG. Since many companies in the United Kingdom have both supplier and shipper licenses, these terms are used interchangeably here. Traders are firms that buy and sell natural gas in a spot market and do not deal directly with consumers or BG.

[2] Based on data from the U.K. Department of Trade and Industry.

[3] Gundi Royle, "British Gas: Light at the End of a Long Tunnel," (Morgan Stanley International, Investment Research U.K. and Europe, London, 1996).

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Development of Competitive Natural Gas Markets in the United States

Andrej Juris

The United States enjoys a highly competitive natural gas market and an increasingly efficient market for pipeline transportation. Consumers have benefited from changes to both the structure and regulation of the industry in the past ten to fifteen years. These changes have lowered natural gas prices and broadened the range of services offered by gas companies. This Note reviews the forces driving the regulatory changes and the effects of the changes on the functioning of gas markets. It also provides an overview of natural gas trading mechanisms in the United States. The focus is primarily on the wholesale natural gas market, the market most affected by deregulation.

Deregulation of the gas industry

The U.S. natural gas market is the world's largest, with a total supply in 1996 of 25.6 trillion cubic feet. About 75 percent of this supply is produced domestically, with the balance from storage withdrawals and imports (12 percent each). Gas production is concentrated in the South, along the Gulf Coast in Louisiana and Texas, and in smaller producing regions in Alaska, the Southwest, and the central United States. But most natural gas consumers are in the Northeast, the Midwest, and the Pacific Coast region, all areas where imports of Canadian gas play an important part in meeting demand. The geographic imbalance between producers and consumers means that large quantities of natural gas must be transported long distances across the country and the continent. So even small inefficiencies in production or transportation of natural gas can have a large economic effect on the gas industry.

The U.S. natural gas industry has gone through a full cycle of government regulation in the past sixty years. During the first several decades of the century the industry enjoyed limited oversight by the government. That changed in 1938, when the Natural Gas Act established a basis for regulating the prices and activities of gas companies. Over the next forty years regulation gradually increased its reach as new regulatory institutions and policies emerged. Interstate transactions came under regulation by the Federal Power Commission (FPC), later succeeded by the Federal Energy Regulatory Commission (FERC), while intrastate transactions were regulated by state agencies.

Overregulation

By the 1970s regulatory agencies controlled almost all aspects of business in the industry. Regulation was applied not only to industry segments dominated by natural monopolies, such as pipeline transportation, but also to competitive segments, such as production and wholesale supply. The excessive control burdened companies and distorted natural gas prices and consumption patterns.

Excessive regulation of gas producers, for example, led to gas shortages in the 1970s.[1] In the 1950s the FPC had started to regulate wellhead prices in areas where interstate pipeline companies purchased natural gas from

producers. But with hundreds of active wellheads in the country, the commission was unable to process all the tariff applications. By 1960 it had completed 10 out of 2,900 applications. It was forced to adopt an "area rates" approach, setting a uniform tariff for all producers in the same geographic area. Although this step decreased the number of tariff cases, the approval process was still very slow, averaging ten years per case.

The area rates were based on average historical costs of production. These averages became very low relative to the increasing costs of production in the 1960s and early 1970s. Producers found sales of natural gas to interstate pipelines unprofitable and curtailed gas supply to the interstate market. They found it more profitable to supply gas to the intrastate market in Texas or Louisiana, for example, where wellhead prices were unregulated or considerably higher than in the interstate market. As a result interstate pipelines faced shortages of gas supply and consumers in the Northeast and Midwest experienced supply interruptions.

Even small inefficiencies in production or transportation of natural gas can have a large economic impact on the gas industry.

To attract producers back to the interstate market, the FPC adopted new regulation in the mid 1970s. A uniform national wellhead tariff was set at an average of current and expected costs of gas production, leading to a quintupling in wellhead prices. However, the new regulation did not eliminate the main cause of gas shortages—the regulation itself. Average cost–based national tariffs seldom reflected the true economic value of natural gas as it would be set in a competitive market. And even if national tariffs did reflect economic value, they applied only to supply contracts concluded after 1975. Supply contracts concluded earlier were priced at low historical tariffs. Since interstate pipelines had a large portfolio of old gas contracts, the average wellhead costs of natural gas were well below the economic value. Consumer demand was therefore much higher than it would have been in a competitive market. This aggravated supply shortages. The costs of gas shortages in the 1970s were estimated at US$2.5–5.0 billion a year.

Deregulation

Gas shortages prompted deregulation in order to promote efficiency in production and bulk supply of natural gas. The main approach was to allow free competition among producers and suppliers in the wholesale gas market. The process was launched in 1978 when Congress adopted the Natural Gas Policy Act, authorizing the FPC to partially liberalize interstate natural gas markets. The FPC adopted a number of regulatory measures that partially liberalized wellhead prices of gas, allowed competition in the wholesale gas market, and enhanced regulation of interstate gas pipelines. Congress adopted additional legislation in 1989 and 1992 further liberalizing wellhead gas prices and interstate natural gas transactions.

Among the most important measures adopted by the FPC was Order No. 436 of 1985, which introduced open access to interstate pipeline transportation and limited the use of long-term contracts. Local distribution utilities and large end users were allowed to purchase natural gas directly from producers, bypassing interstate pipeline companies. Companies that agreed to provide open access to their interstate pipelines were allowed to charge an open access tariff, regulated by FERC, for provision of transportation services. To promote competition in the bulk supply of natural gas, FERC allowed gas marketing companies to arrange purchases and sales of natural gas on behalf of other industry participants.

Deregulation of the gas industry followed when FERC adopted Order No. 636 of 1992, which

FIGURE 1 TRADITIONAL STRUCTURE OF THE U.S. GAS INDUSTRY, BEFORE 1985

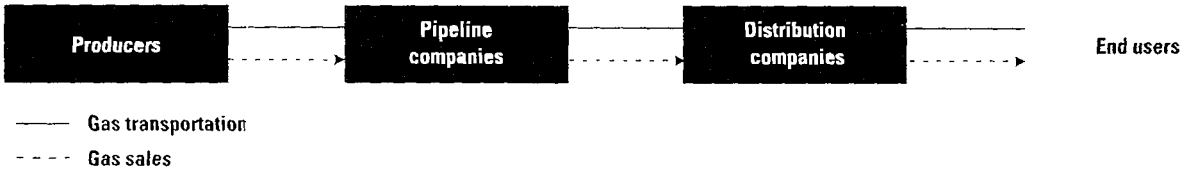


FIGURE 2 OPEN ACCESS TO PIPELINE TRANSPORTATION, 1985–92

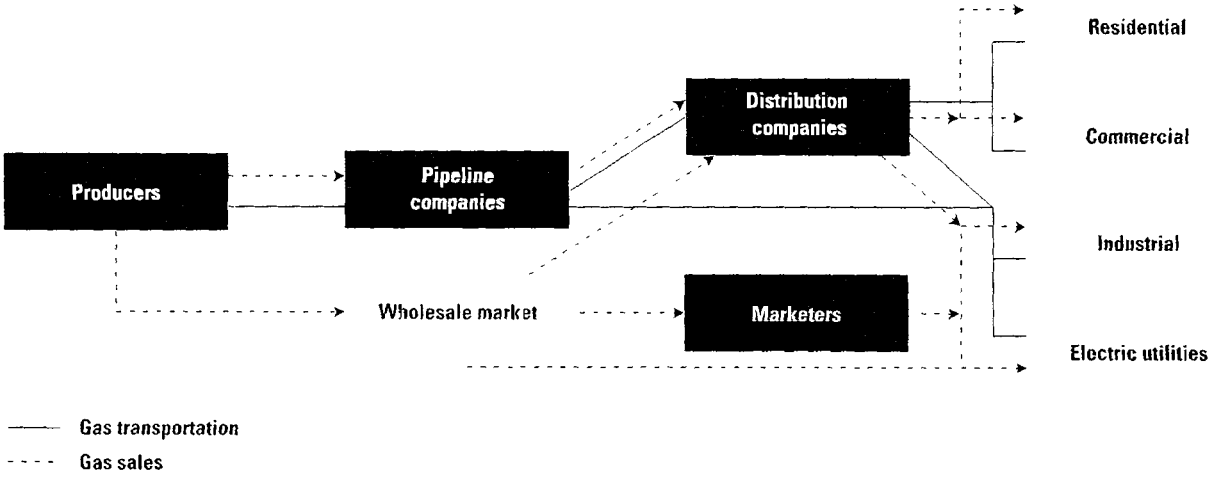
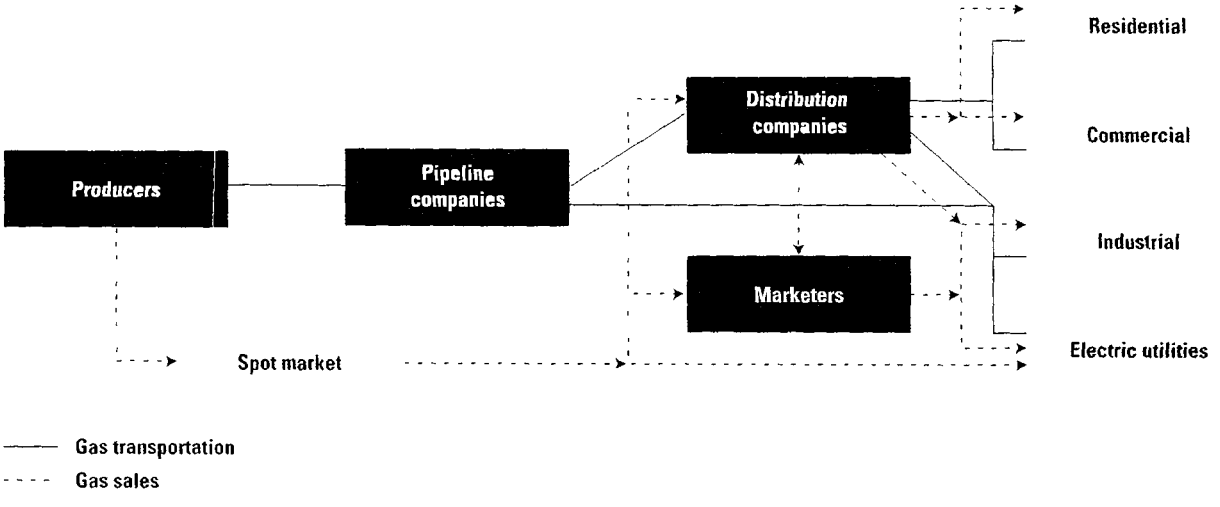


FIGURE 3 UNBUNDLING OF GAS SALES FROM PIPELINE TRANSPORTATION, 1992 AND BEYOND



required the interstate pipeline companies to unbundle natural gas sales from pipeline transportation by setting up separate affiliates to handle these activities. This removed an incentive for interstate pipeline companies to distort bulk supply competition through restricting access to pipelines.

To minimize distortions in the gas market caused by regulated prices for interstate pipeline transportation, Order No. 636 also enhanced the method for calculating transportation tariffs and introduced a program for the resale of firm transportation contracts. This program, the capacity release program, allows shippers (any users of pipeline transportation) to purchase pipeline capacity from shippers that have temporary or permanent excess reserved capacity. The capacity release market promotes the efficient allocation of transportation contracts among shippers and allows gas market participants to match transportation contracts to their gas supply contracts.

The two orders dramatically changed the operation of the gas industry, from tight regulation to free competition in the wholesale gas market. But implementation of the orders imposed large transition costs on some industry participants, which naturally opposed changes. Opposition to Order No. 436 was particularly strong. The transition costs related to Order No. 436 were estimated at US$11.7 billion in 1986, half the total book value of interstate pipelines in 1984, at US$23.4 billion. The actual value of transition costs was $10.2 billion as of 1995.[2] Only after FERC worked out a mechanism to distribute the costs among all industry participants could the orders be successfully implemented and competition flourish.

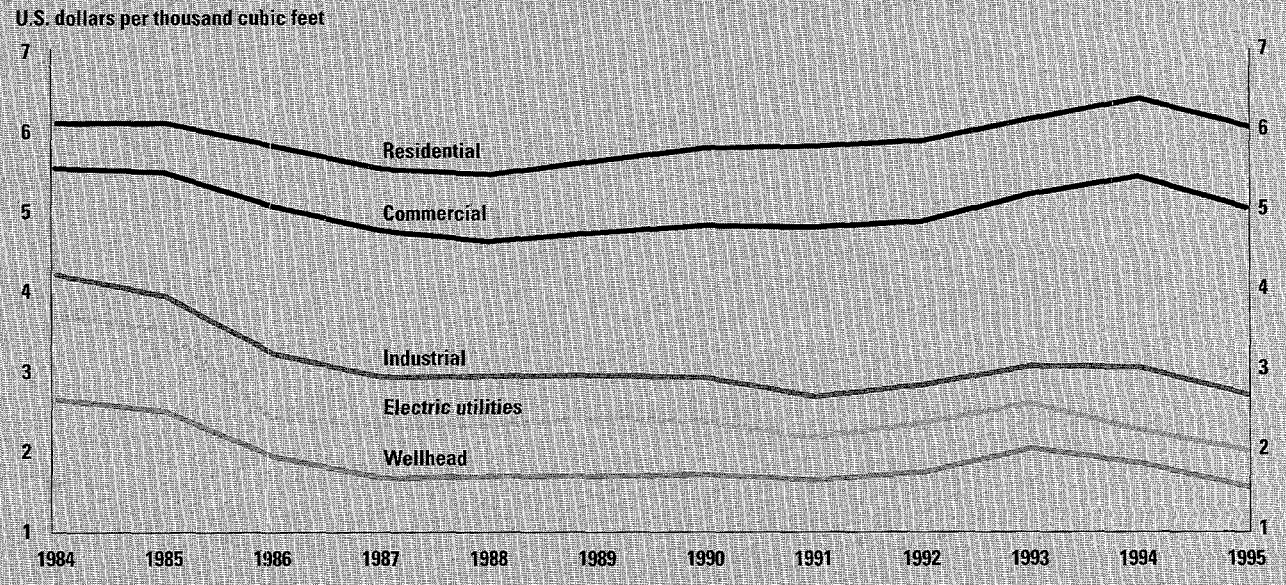
Before 1985 interstate pipelines entered long-term supply contracts to purchase from producers and sell to distribution companies. Many of these contracts were concluded at very high wellhead prices, which pipelines, fearing a recurrence of the supply interruptions of the 1970s, were willing to pay. The uneconomic costs of gas purchases at the wellhead were borne by distribution companies and final consumers, since regulators allowed a pass-through of gas purchase costs to consumers. Order No. 436 allowed distribution companies to exit these long-term supply contracts with pipeline companies and purchase natural gas directly from producers. But pipeline companies were not allowed to exit their contracts with producers and so were left with large contractual obligations that they were unable to meet. The pipeline companies challenged the order in court, and FERC had to issue a new order (Order No. 500 of 1987) allowing the companies to pass on up to 75 percent of the transition costs to producers, distribution companies, and large consumers. Only then did the interstate pipeline companies begin to implement the open access regime on a large scale.

Order No. 636 completed the deregulation of the wholesale gas market by liberalizing entry into gas marketing. It was followed by a series of FERC orders to promote competition in the wholesale gas market and increase flexibility in interstate pipeline transportation. FERC is now focusing on developing short-term capacity resale and standardizing gas supply and transportation contracts.

Deregulation has changed the structure of the U.S. gas industry. Until 1985 the industry was vertically separated into production, pipeline transportation, and distribution (figure 1). However, all transactions were tightly regulated and completed under long-term contracts. The introduction of open access to interstate pipeline transportation in 1985 gave rise to the competitive wholesale gas market, and gas marketing emerged as a new segment of the industry (figure 2). The unbundling of interstate pipeline transportation completed the wholesale market's transformation into a fully competitive market in 1992 (figure 3).

The liberalization of gas marketing and wholesale gas prices attracted many new companies into the wholesale gas market. The fierce competition that ensued among marketing firms and

FIGURE 4 AVERAGE NOMINAL NATURAL GAS PRICES IN THE UNITED STATES, 1984–95



Source: Energy Information Administration, Washington, D.C.

gas producers increased the pressure on wholesale gas prices. The price competition benefited not only wholesale market participants, but also final consumers of natural gas. Nominal prices of natural gas decreased or remained stable for all consumer categories after 1985 (figure 4). This meant a substantial decrease in real prices. Wellhead prices dropped on average 26 percent in real terms between 1988 and 1995, while prices at city gates (the entry points to pipeline networks for local distribution) fell by 24 percent.

Although there was an overall decline in retail gas prices, the distribution of benefits was uneven. Large consumers such as electric utilities and industrial consumers, which now purchase about 75 percent of their gas requirements in the competitive wholesale market, saw a 26 to 31 percent decline in real prices between 1988 and 1995. Most small consumers, however, are still captive to local distribution companies, and only about 25 percent of gas consumed by commercial users is purchased directly in the wholesale gas market. As a result, commercial and residential consumers saw only a 12 percent decline in the average real price of natural gas between 1988 and 1995.

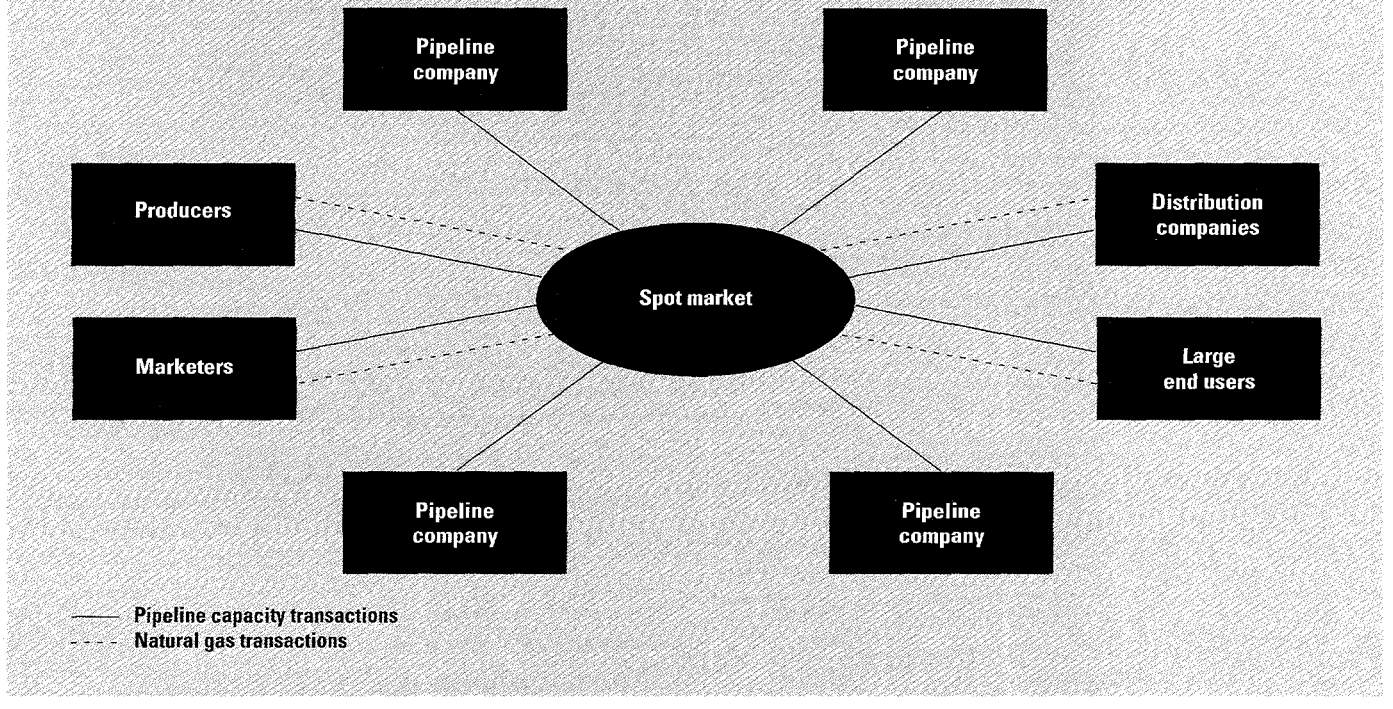
The functioning of a competitive gas market

After fifteen years of deregulation, the wholesale gas market in the United States is fully liberalized and very competitive. Producers, pipeline companies, marketers, distribution companies, and large consumers trade natural gas in a large number of regional markets. Natural gas transactions are mostly arranged by gas marketers, which buy and sell natural gas on behalf of producers, distribution companies, and large consumers. Most trading takes place in spot markets at major market centers and hubs on interstate pipelines (figure 5). Important trading activity also occurs in financial gas markets (futures and options), where participants minimize the price risks in natural gas spot markets. And recently electronic trading systems have developed that allow the trading of natural gas and pipeline capacity in all major markets in the United States and Canada.

Gas marketers

Gas marketing companies are a dynamic and competitive segment of the U.S. natural gas in-

FIGURE 5 TRADING IN MARKET CENTERS AND HUBS



dustry. The share of deliveries they arrange increased from 20 percent of the total in 1987 to 49 percent in 1995. The first marketing companies emerged in the late 1980s, but the main boom occurred after implementation of Order No. 636 in 1992, as producers, pipeline companies, and distribution companies formed marketing subsidiaries to take over natural gas acquisition and sales.

Marketing companies benefit other participants in the gas market by minimizing transactions costs and supply and price risks. They group the supply and demand needs of market participants and match them with appropriate contracts on a large scale. This intermediation reduces the costs of transactions by freeing buyers and sellers from having to shop for the best contract. At the same time, by aggregating contracts, marketers can diversify the supply and price risks of individual contracts. These risks often arise when market participants with different supply and demand characteristics try to arrange transactions on a bilateral basis. Because marketers can pool contracts in one portfolio, they are better able to absorb fluctuations in supply or demand.

As natural gas markets have become increasingly complex, marketing companies have sought to expand their size and scope in order to accommodate the diverse needs of their clients. In 1995 and 1996 a wave of mergers increased the concentration of sales. In 1994 the top ten marketers arranged average daily sales of about 31 billion cubic feet of natural gas, 42 percent of total U.S. daily consumption. In 1996, after mergers between several large players, the top four marketers alone accounted for this volume of sales. Despite this concentration, small marketers continue to play an important role, particularly in local markets, which are commercially unattractive for major players.

Hubs and spot markets

Over the past ten years natural gas transactions in the wholesale market have gradually moved from wellheads to hubs at major interconnections of interstate and intrastate pipelines. Today most gas trading in the United States takes place in large hubs and market centers. Hubs are typically operated by one or several interstate pipeline companies, which own the pipelines interconnected at the hub. Hubs allow market

participants to acquire natural gas from several independent sources and ship it to several different markets. This eliminates the need to contract natural gas and pipeline capacity all the way from the wellhead to the consumption site. Instead, shippers can combine supply routes across several hubs to diversify supply risks and minimize costs. Hub operators offer a wide variety of services—ranging from physical transportation of natural gas to storage, processing, and trading—providing great flexibility for shippers and marketers in trading and delivering natural gas.

Hubs have become very popular among marketers and other players in the wholesale gas market. More than fifty have been created across the United States since the first one, the Henry Hub, was established in May 1988 in Erath, Louisiana. The Henry Hub, which is also the largest hub in the United States, is a major natural gas interchange operated by Sabine Pipe Line Company, a subsidiary of Texaco. At this hub marketers and traders have access to large consumer markets in the Midwest, Northeast, and Southeast and along the Gulf Coast through nine interstate and three intrastate interconnecting pipelines. The market participants transported about 550 million cubic feet of gas a day through the Henry Hub in 1995.

Almost all major hubs in the United States have developed into spot markets where natural gas is traded continuously. The most important natural gas spot market is at the Henry Hub. This highly liquid and efficient spot market determines the market price of natural gas on a continuous basis. The Henry Hub spot price plays a key role in the U.S. gas industry. Gas industry participants use the spot prices to evaluate their contract portfolios and make consumption or investment decisions. And the Henry Hub is the pricing point for the first financial gas contract, the New York Mercantile Exchange (NYMEX) natural gas futures contract.

Financial gas market

Participants in natural gas spot markets in the United States face substantial price risks, as spot gas prices occasionally become highly volatile. A cold spell in February 1996, for example, caused extreme changes in spot prices at the Henry Hub. The average spot price in February 1996 was US$4.41 per million British thermal units (Btu), a record high compared to the average annual price of about US$2 per million Btu. The spot price at Henry Hub peaked at more than US$15 on February 2, 1996, and some industrial customers in Chicago paid a city gate price of US$45 per Btu.[2]

Most players in the gas market dislike high volatility in gas prices and seek ways to diminish the price risk in the financial gas market. They are aided by a large number of intermediaries—gas marketers that compete fiercely to structure the best ways of minimizing price risk for customers.

The U.S. financial gas market had its beginnings in the late 1980s, when several financial institutions began to offer custom-tailored natural gas futures contracts. As noted, the first standardized financial gas contract was introduced by NYMEX in April 1990, in the form of a natural gas futures contract with delivery at the Henry Hub. In April 1992 NYMEX added a natural gas options contract for delivery at the same location. NYMEX and the Kansas City Board of Trade have since introduced three more natural gas futures and options contracts, with three different delivery locations, to reflect regional differences in the market value of natural gas.

Financial gas trading has proved popular among gas market participants. Between 1991 and 1995 the volume of natural gas futures contracts traded increased from 0.42 trillion cubic feet to 80 trillion—four times the physical consumption of natural gas in 1995. The turnover in futures trading was US$125 billion in 1994, about 60 percent more than the turnover in physical gas that year. Most financial gas trading is conducted by marketers (which held 34 percent of the open interest on natural gas futures in the first quarter of 1996), producers (25 percent), and financial institutions (20 percent).

Electronic trading and market centers

The introduction of electronic trading systems in the past two years has led to the development of market centers connected to multiple hubs by electronic networks. Electronic trading allows market participants to trade not only natural gas, but also pipeline capacity and storage services at all interconnected hubs and pipelines. It also facilitates communication between pipeline companies, shippers, and hub operators. Many electronic trading systems are linked to other commercial networks that supply information and news relevant to the gas industry.

Electronic trading has its origins in the electronic bulletin boards established by interstate pipeline companies in 1993 to support resale of pipeline capacity. Standardization of these electronic bulletin boards simplified the trading of pipeline capacity and showed the advantages of electronic trading. In late 1994 three commercial electronic trading systems were introduced that allowed market participants to trade natural gas and pipeline capacity electronically across several markets and pipelines. By the end of 1996 almost all major pipeline companies in the United States had introduced electronic systems.

The largest electronic trading system in the United States today is Altra Streamline, which is linked to eight market centers and forty-five interstate pipelines in the United States and Canada. The average daily volumes traded in this system range from 10 million to 200 million cubic feet of natural gas. Many small systems are integrating with larger ones to offer shippers and marketers a wide variety of services across all major gas markets in the United States. Electronic trading systems have great potential in the world of deregulated natural gas and power industries: they can link marketers to all major regional gas and electricity markets in the United States.

Conclusion

The U.S. experience in gas industry deregulation shows that the development of competitive gas markets must be supported by continuing improvement of the regulatory framework for the gas industry. Such measures as liberalizing wholesale gas prices and the bulk supply of natural gas free market forces in segments where competition is both feasible and socially desirable. Regulators also must focus on improving the regulation of pipeline transportation and minimizing its distortive effect on competitive gas markets. Introducing flexibility into pricing and other conditions of transportation contracts—such as delivery locations or the balancing of gas shipments—and standardizing pipeline operations promote more efficient use of pipelines and benefit all industry participants.

The U.S. experience also shows the viability of competition in the deregulated wholesale gas market and the important role of gas marketers and spot markets in increasing the efficiency of gas transactions and prices. Liberalized wholesale prices create many profit opportunities in the gas market, and these attract new entrants to production, marketing, and supply. Many of the new entrants bring new services and products that increase the range and quality of choices for gas industry participants.

Deregulation of the U.S. gas industry is far from complete, however. Regulation of charges for interstate pipeline transportation and capacity release still limits the efficient allocation of transportation contracts. But the most important task, and the biggest challenge for regulators, remains the deregulation of retail gas markets in individual states. These issues will continue to keep U.S. gas regulators busy.

[1] This example draws on Richard J. Pierce Jr., "Reconstituting the Natural Gas Industry from Wellhead to Burnertip," *Energy Law Journal* 9 (January 1988): 1–57.

[2] Pierce (1988) and U.S. Department of Energy, *Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates* (DOE/EIA-0602[95], Energy Information Administration, Washington, D.C., 1995).

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Mitigating Risks in Power Reform—A New World Bank Lending Approach

Power Sector Reform in the Indian State of Haryana

Djamal Mostefai

The World Bank has agreed to support power sector reforms in Haryana with a new type of lending instrument—the adaptable program loan—recently approved by its board of directors. Under this approach, being applied for the first time, the Bank will provide a series of loans totaling US$600 million over eight to ten years, but will commit the loans only when the state government has reached agreed milestones. This approach allows state government milestones—not the covenants of standard World Bank loans—to determine the timing of controversial actions. The flexibility is intended to improve the reform program's chances of success and avoid a stop-start lending pattern. This Note explains Haryana's reform strategy and how the adaptable program loan applies.

The power sector of the northern Indian state of Haryana is in poor physical and financial condition. To put the sector on more solid footing, the state government has announced a ten-year program of comprehensive reform to restore its creditworthiness, create an environment conducive to private investment, and eliminate the power deficit. The government will create an independent regulatory commission, unbundle the sector, privatize distribution, and rely on the private sector to create additional generation capacity. It will also rationalize tariffs, notably for power supplied to agriculture, the state's dominant sector. The strategy is expected to help mobilize about US$5 billion in investment in generation, transmission, and distribution from independent power producers, distributors, central and regional utilities, and Haryana's state-owned central utilities.

Implementing the reform program will be complex, however, and will entail significant risks, particularly political ones. The sector is dominated by the Haryana State Electricity Board, a state-owned, integrated utility with a monopoly on transmission and distribution. (Although generation was opened to private independent power producers in the early 1990s, there were no takers. Project sponsors were unwilling to enter the market given the power offtaker's dismal financial condition and the federal government's unwillingness to extend sovereign guarantees.) As Haryana's policymakers now largely recognize, the root cause of the sector's problems is the lack of a commercial outlook in operations and investment and the multiplicity of goals the Board has to pursue (box 1). The Board has been required to charge low tariffs to farmers and residential consumers and to refrain from using normal remedies to collect bills and to eliminate large nontechnical losses. Over the years the Board has been transformed into an extension of the state government.

The loan's flexibility is intended to improve the reform program's chances of success and avoid a stop-start lending pattern.

BOX 1 THE PROBLEM

The Haryana State Electricity Board, a state-owned, integrated utility with a monopoly on transmission and distribution, cannot meet the demand for electricity. Power shortages exceed 25 percent, costing Haryana's economy some US$350 million to US$400 million a year, 4.0 to 4.5 percent of the gross state domestic product. For eight years the Board has been unable to afford to add to its generating capacity, which remains at about 2,400 megawatts.

System losses are estimated to exceed 40 percent, and more than half are nontechnical losses (unmetered and unbilled supply, uncollected bills, power theft, pilferage). Power stations operate at an average load factor of only about 45 percent, mainly as a result of poor physical condition, the low quality of coal, and its irregular supply (due in part to the Board's poor payment record).

By March 1997 the Board had accumulated financial losses of more than US$850 million, it had a negative worth of US$72 million, and overdue liabilities to suppliers (mostly bulk suppliers of fuel and electricity) exceeded US$250 million. In the past eight years the state has granted the power sector more than US$1 billion in direct and indirect subsidies, equivalent to about 70 percent of the state's fiscal deficit.

The reform strategy

The comprehensive reform program announced by the state government has five main features.

First, the government will develop an autonomous regulatory agency that will issue licenses to transmission and distribution companies and regulate the tariffs and performance of power utilities, whether owned by the government or the private sector. Creating this agency should be a major step in depoliticizing the sector and reducing interference by the state government, especially in tariffs.

Second, the government will unbundle generation, transmission, and distribution, thus separating the Board into a generation company, a transmission company, and several distribution companies. Initially the industry structure will follow the single-buyer model; later, it is expected to evolve to wholesale competition.

Third, the government will privatize distribution and rely on the private sector to develop additional generating capacity through a competitive bidding process. It may also allow power imports from neighboring states and from Nepal. The distribution companies, which serve about 3 million consumers, will be privatized through the sale of equity to private strategic investors, with the state keeping a minority equity stake. The first privatization should be completed by the middle of 1999 and the rest before the end of 2001. There is growing consensus in India that privatizing distribution is the best way—if not the only way—to reduce the huge nontechnical losses plaguing the sector. Generation and transmission assets may also be considered for privatization in the long run. In the short term, however, the government of Haryana prefers to focus its privatization efforts on what is most essential to the success of the reform—distribution. Success on that front is expected to ease later privatization efforts in generation and transmission.

Fourth, bulk power, transmission, and retail tariffs will be rebalanced. Over the next four years retail tariffs will be progressively adjusted to restore the creditworthiness of the utilities and to reduce the subsidies given to agricultural and domestic users. By 2001–02 utilities should achieve a return on net worth of at least 16 percent, with a self-financing ratio of at least 20 percent.

Finally, the sector will undergo comprehensive financial restructuring. The state government will forgo its equity and loans to cover accumulated losses, write off losses and contingent liabilities, and provide temporary support to the new utilities. In addition, the Board will discuss with its creditors the possibility of re-

scheduling some current liabilities and other obligations. This financial workout would involve restructuring about US$1 billion of liabilities. But after 2002 the power sector will be able to meet its debt service obligations and become a net contributor to the state budget by paying returns on the state's equity.

Under the investment program new generation capacity will be developed by central and regional utilities (20 to 30 percent of the additional capacity needed) and private interests (70 to 80 percent). Rehabilitating the existing generation facilities and rehabilitating and expanding the transmission and distribution network will require about US$1.8 billion. Funding will come from the World Bank (33 percent), bilateral donors (14 percent), the Haryana state government (16 percent), and internal resources generated by the new power companies (12 percent), with private equity and Indian and foreign commercial banks providing the balance.

Implementation risks

The success of the proposed reforms hinges on the state government's ability to achieve three main goals.

First, the state government must be able to significantly increase tariffs over the next four years, especially for electricity supplied to agriculture, which accounts for about 45 percent of the market (compared with 23 percent for industry and 19 percent for residential consumers). Haryana is one of the few states in India in which power rates for agriculture are more than the roughly 1.3 U.S. cents per kilowatt-hour minimum set by a conference of chief ministers at the end of 1996. Most states still provide farmers with free power (as in Punjab and Tamil Nadu) or charge them less than the minimum.

Second, the state government must be able to privatize distribution. The move toward privatization will generate forceful opposition from different constituencies and on various grounds: ideology, employee fears of massive layoffs, concern about undue increases in tariffs, and unwillingness among vested interests to give up their benefits.

And third, the utilities must be allowed to function as autonomous, accountable, and commercial entities without any external daily interference or micromanagement. They should be expected to pursue only commercial and efficiency objectives; they should not be expected to pursue any social objectives that the state government may have and that in any case would be better achieved through other means.

There is a growing consensus in India that privatizing distribution is the best way to reduce huge nontechnical power losses—unmetered and unbilled supply, uncollected bills, power theft and pilferage.

The complexity of the reform poses another important risk. The program will be both technically and administratively challenging, as demonstrated by a similar reform program launched about two years ago in the Indian state of Orissa and partly funded by the World Bank. The proposed changes are based on concepts and mechanisms new to most of the people who will have to implement them. The program will require increased institutional capacity and a new management culture and attitudes. Full implementation will take about ten years. Among the complex issues that the government of Haryana will have to address:

- Moving from an integrated, monopoly utility to a structure in which several generating companies, a transmission company, and several distribution companies will trade power and operate on a commercial basis.

- Moving from a culture dominated by engineering and technical performance standards, physical targets, administrative controls, and a complex system of accountability to a culture in which the overarching principles, beyond technical excellence, will be quality of service, customer satisfaction, economic and financial efficiency, and clear accountability.
- Moving from a regulatory mechanism in which the key players are the state government and the State Electricity Board to a regulatory mechanism based on an autonomous commission acting independently, following quasi-judicial procedures, conducting public hearings, and assessing tariff adjustment cases from an efficiency perspective.
- Transferring staff, assets, and liabilities from a single entity to several new corporations, and delineating new service territories for the distribution companies.
- Procuring additional power of about 3,000 megawatts, largely from private sources and through competitive bidding, in five to eight years.
- Privatizing distribution, which will require carrying out extensive preparatory work (asset valuation, financial viability analysis, formulation of bidding documents), defining a privatization strategy, negotiating joint ventures, and dealing with labor, legal, and other complex issues.
- Executing an investment program over the next ten years of about US$1.8 billion, five to six times the size of the Electricity Board's past programs.

Farmers and households will pay higher rates as long as they see more and better quality power and do not bear the costs of inefficiencies.

The highest priority for the government is to undertake investments that would reduce system losses—and thereby reduce the tariff hikes needed to cover costs—improve power supply, and enhance revenue collection.

One indication of the complexity of the program is the amount of technical assistance required. Despite all the benefits that Haryana is gaining through learning from the Orissa experience, the technical assistance budget exceeds US$30 million.

Mitigating risk

Mitigating the risks of the reform program poses challenges not only for the reformers in Haryana, but also for the Bank (as adviser and partner to the state government) and for the bilateral agencies that have agreed to provide assistance.[1] The first challenge was to set the right expectations. The state government needed to get the assurance of long-term financial support and it needed to deliver better service early in the reform process to show that something concrete was happening. But from the Bank's perspective it was important to reconcile the need for early support with the risk that the reform could be slowed or even reversed. The Bank's past experience in lending to state electricity boards has been disappointing: of about US$1,800 million in loans committed for state electricity boards, only one-quarter has been disbursed, with the balance canceled because covenants and other commitments could not be met.

The second challenge is to break a vicious circle. Farmers and other consumers will pay higher rates as long as they see more and better-quality power and do not bear the costs of inefficiencies. Experience in Rajasthan bears this out: a scheme in which farmers without electricity but ready to pay the full cost for it will

receive immediate service connections (rather than waiting for years) has elicited broad interest. In most states farmers use diesel generators as a backup or substitute for grid-supplied power, producing power at a much higher cost (3.5 to 4 rupees per kilowatt-hour) than that for power from the grid (about 0.6 rupee). Thus the acceptability of the reforms and the state government's ability to sustain them are directly linked to progress in improving the quantity and quality of supply. The highest priority for the government is therefore to undertake early investments that will reduce system losses—and thereby reduce the tariff hikes needed to cover costs—improve power supply, enhance revenue collection, and lower energy requirements through end-use efficiency improvements.

The third challenge is to deal with the uncertainties and complexity of the reform program. Clearly, it would have been impossible to define at the beginning of the program all the parameters of the policy measures and of the physical components of the Bank's support—something that would have been required using existing loan instruments.

What is different about the adaptable program loan?

The situation Haryana's government faces is not unique. The Bank recognized its clients' need for a new instrument allowing a long-term commitment from the Bank to support long-term programs and policies, early support to help overcome initial difficulties, and flexibility to benefit from the lessons of experience and adapt to evolving situations—something existing instruments did not allow for. The adaptable program loan is the instrument it developed to meet this need.

This loan offers several advantages over investment loans and sectoral adjustment loans to address situations like Haryana's. The World Bank's standard investment loan covers only about five years and is committed only after a number of reform measures have been completed, in an attempt to ensure irreversibility of the reform. This is the approach used to support the pioneering Orissa power sector reform; a US$350 million investment loan was approved by the Bank in 1996, when the adaptable program loan was not yet available. With strong political support from the start and commitment from reform-oriented administrators, Orissa was able to take the up-front measures that enabled the Bank to approve the loan.

A significant difference between the traditional and adaptable program loans lies in the way commitments from the clients are handled.

Some of the circumstances under which the reform was initiated in Orissa were unique: agriculture's share of the power market is quite low (about 7 percent of power sales), tariffs have been regulatory adjusted, and the state does not incur power shortages to the same extent as other states, including Haryana.

A World Bank sectoral adjustment loan might, by contrast, be used, when a country faces balance of payments problems. For Haryana this lending instrument would have been less appropriate than an adaptable program loan for several reasons. A sectoral adjustment loan is disbursed in tranches, after specific conditions have been met, not against expenditures, so the link between the physical components of the investment program and the reform program would have been lost. Extending a sectoral adjustment loan over ten years would have been too long for this type of instrument (and a commitment to provide several shorter loans would not have been possible), and the commitment fees paid by Haryana's government would have been very high. And, finally, the conditions under which the tranches can be released would mean the loss of an important element of flexibility.

A significant difference between these traditional loans and the adaptable program loans lies in the way commitments from clients are handled. In the traditional approach these commitments are covenanted in the legal agreements among the Bank, the borrower, and the beneficiary institutions. Under an adaptable program loan the commitments are milestones that trigger the processing of subsequent loans. A covenant and a milestone are two very different things (box 2).

Loan structure

The Bank has agreed to support the reform program through a series of adaptable lending loans. In January 1998 the Bank's board of directors endorsed Haryana's reform program and approved a first loan of US$60 million as part of a long-term assistance program of up to US$600 million, dispersed over eight to ten years. The subsequent loans for which the board has delegated approval authority to the Bank's management (subject to certain procedural conditions) will be processed once agreed milestones have been achieved.

The loan was approved after the state government had demonstrated its political commitment to reforms. It had conducted an extensive public debate on the reform program, and the State Assembly had passed the Haryana Electricity Reform Bill, a major step in implementing the reform. (A standard lending operation would have required much more progress on the reform agenda before commitment of a Bank loan. But that would have delayed Bank support at a time when this support is critical.) The loan will help finance investments in transmission and distribution to increase the supply and quality of power in selected areas where the results will be most visible. It will also finance improvements in customer service (for example, in the operation of complaint centers and in billing procedures) and new safety equipment for staff. Several bilateral donors have agreed to finance a comprehensive program of technical assistance to start the institutional development of the new power sector entities.[2]

If Haryana's government keeps its current reform schedule and makes timely procurement decisions, the second loan, of US$150 million to US$200 million, could be extended in late 1998 or early 1999. This loan would be aimed at helping to sustain the major reforms and supporting tariff adjustments, notably for power supplied to agriculture. The loan would finance the continuation of the investment program in transmission; basic distribution equipment (meters, transformers, capacitors) and the rehabilitation of more distribution segments; and demand-side management and energy conservation measures (such as replacing

BOX 2 COVENANTS AND MILESTONES

A covenant is part of a set of legal commitments on which the Bank has premised its decision to lend. A borrower's failure to meet a covenant constitutes a breach of commitment, and the Bank may have to take remedial actions, including suspending disbursement and canceling loans. These actions are essentially punitive and almost inevitably lead to difficulties in the dialogue between the Bank and the borrower.

A milestone is a target set by the borrower that the Bank has agreed to consider a trigger for processing subsequent loans. The decision to achieve this target rests exclusively with the borrower, and availing itself of a loan from the Bank is only one of the factors in that decision. If achievement of the milestone is delayed, additional lending may be postponed, but the onus will rest with the client.

An assessment of the differences between covenants and milestones must take in account an important discounting factor. For the Bank, taking remedial actions is generally more difficult than simply not processing a loan when milestones are not met. This discounting factor may sometimes lead clients to agree on covenants that are difficult to meet, with the expectation that during project implementation these covenants will be relaxed.

inefficient water pumps) to ease the impact of rural tariff increases.

The second loan's schedule and amount will depend on progress in the investments financed under the first loan, new investment requirements, the pace of procurement decisions, and contributions from other sources (Japan's Overseas Economic Cooperation Fund and Germany's KfW are actively considering financing part of the second phase of Haryana's investment program). The milestones that Haryana's government will have to achieve before this loan is committed include establishing the regulatory commission and the new power utilities, completing the financial restructuring, and achieving significant progress toward privatization of the first distribution company.

A third loan, for about US$200 million, could be committed in 2001 or 2002. This loan would support the expansion and rehabilitation of the transmission and distribution network. Again, the schedule and amount of the loan will depend on progress in the reform and investment programs and the sector's ability to mobilize financing from other sources. The loan would be committed once most of the distribution business has been privatized, tariffs have been adjusted to meet agreed financial targets, and all other reforms have been implemented as agreed.

Depending on the sector's needs, one or two more loans amounting to about US$200 million would be committed around 2004–05. As with the previous loans, the schedule and amount of these loans would be based on progress in implementing the reforms and related investments. The milestones triggering these loans have been broadly defined. They include full privatization of distribution, full restoration of the sector's creditworthiness, and further evolution of the power industry (for example, toward a multiple-buyer model).

Conclusion

From the Bank's point of view this proposed approach greatly mitigates the implementation risk: its initial financial commitment is limited, and additional commitments are contingent on the completion of concrete reform steps. But once each loan is committed, the funds will normally remain available for disbursement unless there is a clear indication that the reform program is being reversed or there is a continuous beach of basic covenants. A slowdown in reform would defer the next loan, but support to investments initiated under preceding loans may not be affected. That ensures continuing support to Haryana during times of difficulty in implementing reform, even if additional lending remains on hold.

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The progress of the reform program will depend on how well Haryana can manage multiple constituencies to maintain a consensus for reform. The adaptable program loan approach will enhance the reform program's chances of success if the flexibility of the loans and of the milestones can be maintained, so that Haryana's government, not strict dated covenants, determines the timing of controversial actions. This flexibility provides important reassurance to the government, and to other states governments, that the Bank will remain an active partner in the reform program, including during times of trouble.

The proposed power reforms could have an important demonstration effect. Haryana is a high-profile agricultural state near Delhi.

The proposed power reforms could have an important demonstration effect. Haryana is a high-profile agricultural state near Delhi. If successful, the program could help trigger reforms in other agricultural states facing similar problems and challenges.

[1] These are the Canadian International Development Agency, the U.K. Department for International Development, and the U.S. Agency for International Development.

[2] See note 1.

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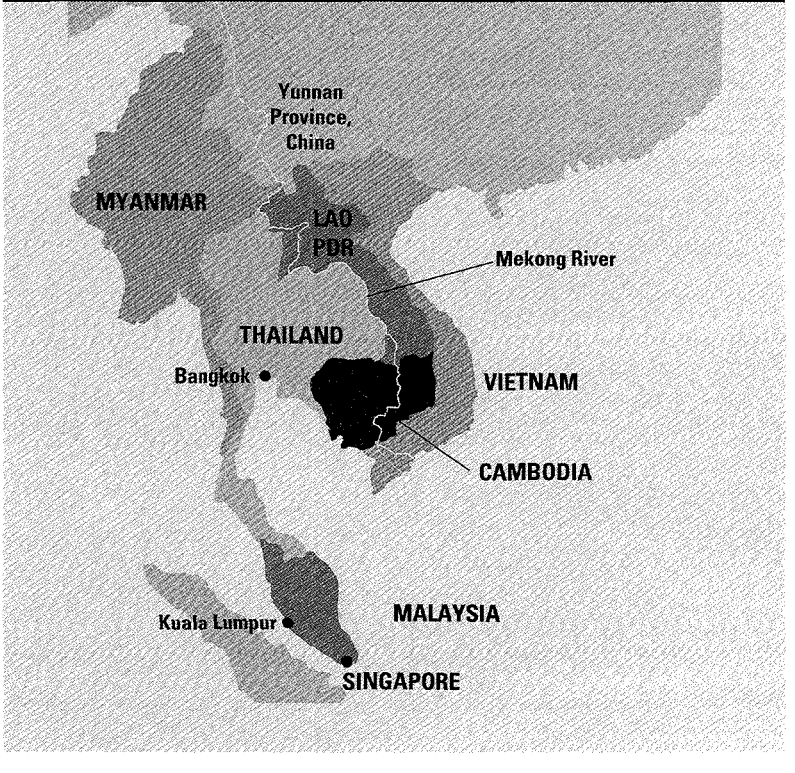
Developing International Power Markets in East Asia

Enrique Crousillat

The Greater Mekong subregion has good potential for international power trade. Initial interest in this market is being spearheaded by private developers negotiating bilateral cross-border trade agreements. But experience in power trade zones in Europe and North America shows that to achieve the benefits of fully fledged trade, the countries in the subregion need to closely coordinate electricity sector policy, operating protocols, and network development. This Note sets out the market development options, reviews sector reforms so far, assesses the obstacles to full power trade, and briefly outlines multilateral efforts to promote an infrastructure that will support international power trade in the subregion.

The Greater Mekong subregion—Cambodia, Lao People's Democratic Republic, Myanmar, Thailand, Vietnam, and the Yunnan Province of southern China—has significant potential for cross-border power trade (table 1). The subregion is well endowed with low-cost hydro resources—the Mekong River Basin is the world's twelfth largest river system—and China, Lao PDR, Thailand, and Vietnam have large coal and natural gas reserves. The potential for trade stems from imbalances in costs and in supply and demand between countries in close proximity: the low-cost hydro potential is in Lao PDR, Myanmar, and Yunnan Province, but the main markets are Thailand and the more distant Malaysia-Singapore grid (about 1,000 kilometers away).

FIGURE 1 THE POTENTIAL EAST ASIAN POWER MARKET



Potential benefits

Recent studies comparing scenarios of electricity self-sufficiency in each country with a full trade scenario show that full trade could yield cost savings of at least US$10.4 billion in 2001–20 and a reduction of airborne pollutants valued at US$160 million a year. (These estimates assume a significant slowing in power demand

TABLE 1 SELECTED ECONOMIC AND POWER INDICATORS IN EAST ASIA

	Cambodia	Lao PDR	Myanmar	Thailand	Vietnam	Malaysia	Singapore
Population (millions)	10	5	43	61	76	20	3
GDP per capita (U.S. dollars)	1,266	2,071	677	13,235	1,263	8,763	21,493
Annual electricity use (kilowatt-hours per capita)	55	55	60	900	198	1,777	6,451
Electrification (percent)	10	18	15	98	30	95	100

Note: Estimates of GDP are based on purchasing power parities rather than exchange rates as conversion factors.
Source: World Bank estimates.

over the next few years in Thailand as a result of the current financial crisis.) The savings would arise from:

- Lower operating costs due to economic power exchange, postponed and lower investments in generation due to least-cost development of regional energy resources, and reduced spinning reserve costs.
- Lower coincident peak load (compared with the sum of individual peak loads), mutual access to generation reserves for interconnected systems, a more robust power supply to meet such unexpected events as load growth above forecast or delayed commissioning of generation and transmission projects, and increased system reliability.
- Lower greenhouse gas emissions and other pollutants, largely due to a shift from thermal to hydro generation in the long term.

BOX 1 THE LOGIC OF TRADE

Power transfer costs are relatively high in countries where there are long distances between in-country load centers, such as Hanoi and Ho Chi Minh City. If a cross-border trading system was in place, rather than transferring power from north to south, Vietnam could meet energy demand at a lower cost by exporting surpluses in the north to Thailand and importing the same amount from Lao PDR.

There is growing interest in cross-border bilateral power trade in the subregion, spearheaded by private developers in Lao PDR selling power to Thailand. The government of Thailand has agreed to buy 3,000 megawatts from these private power developers by 2006, and several independent power producer (IPP) projects are moving ahead. China's Ministry of Electric Power is encouraging studies of the export potential of Yunnan's planned Jing Hong hydropower plant and associated transmission lines to Thailand, through Lao PDR, with the support of the Lao and Thai governments. The Vietnam and Lao governments have signed a memorandum of understanding on purchases of about 2,000 megawatts of power by 2010.

Developing international markets

Experience in power pool development in Europe and the United States suggests that to get the full benefits of that trade, countries in the Greater Mekong subregion will have to go beyond the proposed bilateral power purchases.

They will have to ensure compatibility in their power sector structures, conditions for private entry, and market competitiveness. An international power market requires coordinated development and operation.

The three main models for international power markets can be regarded as three phases of a continuum:

- The single-buyer model.
- The third-party or open access model.
- The spot market or wholesale market (power pool) model.

Single buyer

In a single-buyer market a single entity, such as the Electricity Generating Authority of Thailand (EGAT; see box 2), purchases power from all producers on a contractual basis. This approach does not require a radical separation of integrated utilities or significant power sector reform. But the long-term contracts should be structured like IPP contracts, providing for separate payments for capacity and energy to compensate producers that maintain high levels of plant availability. This model would provide limited benefits for competition because sales would tend to be based on long-term contracts. It might also lead to inefficiencies in investment, such as duplication in transmission.

More competitive single-buyer models require some vertical and horizontal separation of generation, transmission, and distribution. Vertical separation facilitates competition among power generators and makes it possible to identify the costs of transmission and to set prices for grid use. These prices normally need to be regulated through a transparent and predictable price review mechanism. To get the benefits of competition, though, governments should ensure that no large generators command excessive market power.

Open access

The open access, or third-party, model opens the transmission system to generators so that

BOX 2 SECTOR OPERATORS

The power sectors in the Greater Mekong subregion are structured differently.

Cambodia. **Electricité du Cambodge is a state-owned utility responsible for the supply of electricity nationwide. Electricity supply is largely restricted to the capital, Phnom Penh, and a few provincial towns; there are no transmission facilities in Cambodia.**

China. **In Yunnan Province, the Yunnan Provincial Electric Power Corporation operates as a fully integrated power company, wholly owned by the government. The South-East China Electric Power Corporation (SCEP) was set up as a joint venture company in Guangzhou by China's central government, the State Energy Investment Corporation, and Guangdong, Guangxi, Guizhou, and Yunnan province in 1991. The SCEP constructs and manages jointly funded generation and transmission projects. It is exploring the feasibility of a regional power pool.**

Lao PDR. **The national utility Electricité du Lao, established in 1961, is responsible for all supply in the country. But electricity supply is largely restricted to the capital, Vientiane, and a few provincial towns, since transmission facilities are limited.**

Malaysia. **Tenaga Nasional Berhad operates as a fully integrated power company; it purchases all power produced by independent power producers.**

Myanmar. **Myanmar Electric Power Enterprise was constituted in 1989 as a government-owned, fully integrated utility. It is responsible for planning, designing, constructing, maintaining, and operating electricity supply facilities throughout the country.**

Thailand. **The country has three government-owned utilities: Electricity Generating Authority of Thailand (EGAT), Metropolitan Electricity Administration (MEA), and Provincial Electricity Authority (PEA). EGAT is responsible for bulk supply, MEA for distribution in Bangkok, and PEA for supply in the rest of the country. These utilities are well established, profitable, and well managed. The government plans to privatize them through public stock offerings.**

Vietnam. **Electricity of Vietnam was established in 1995 as a wholly government-owned holding company for the power sector. It coordinates the three formerly fully integrated power companies, which had been based in Hanoi, Danang, and Ho Chi Minh City.**

TABLE 2 STATUS OF POWER REFORM IN EAST ASIA

	Fully integrated sector	Independent regulation	Degree of unbundling	IPPs permitted	Single-buyer model	Transmission access	Wholesale competition
Thailand		Under study	Unbundling of distribution and generation in progress	√	√	Limited access planned	No
Malaysia	√	Set up in 1991	Unbundling of generation and transmission under consideration	√	√	No	No
China		Under study	Partial unbundling of generation and transmission	√	√	No	No
Vietnam	√	Law being drafted	Generation and transmission to be operated as profit centers	√	√	No	No
Lao PDR	√	Not planned	Creation of separate transmission company being considered	√	√	Under study	No
Cambodia	√	Law being drafted	Not planned	√	√	No	No
Myanmar	√	Not planned	Not planned	√		No	No

they can wheel power directly to distributors or large bulk customers. Access to transmission must therefore be regulated, and pricing policies compatible, transparent, and efficient. Vertical separation of transmission avoids the conflicts of interest that can arise if a transmission entity favors its own generation source. Under the open access model most exchanges would still be based on long-term contracts, but short-term trade could occur if countries have spare capacity or energy.

Power pool

The final stage in developing an international power market is to form a regional power pool or wholesale market allowing regional power producers to sell directly to any distributor or bulk customer. This model requires a regulatory framework to guarantee a fair and efficient market, including mechanisms to facilitate and coordinate trade. Again, governments must ensure that a few large generators

do not dominate the market and inhibit competitive power pooling.

Market reforms so far

All governments in the subregion have fostered the beginnings of power trade by opening the generation market to IPPs, though their success in attracting private investment has varied. IPPs have been active in Lao PDR, Malaysia, and Thailand, but they have shown less interest in other countries. Nearly all governments are moving toward a single-buyer model (table 2). In Thailand, for example, EGAT's transmission entity is responsible for power purchases—though IPPs (with 10 percent of generating capacity) will have some access to the grid for direct sales to large consumers. In Malaysia Tenaga Nasional Berhad (TNB), the government-owned, fully integrated utility, purchases all power produced by IPPs (which have about 30 percent of generating capacity).

Thailand has made the most progress in unbundling transmission, distribution, and generation. In China the central government is moving slowly to encourage competitive generation. The Yunnan provincial power corporation is developing the single-buyer model and has signed long-term power purchase agreements with projects sponsored by other government entities. The Lao government plans to establish a separate transmission company to provide wheeling services to the region. It also is considering separating export power plants from local supply. The government of Vietnam plans to operate generation and transmission as profit centers, but whether it will permit full unbundling is unclear. The governments of Cambodia, Lao PDR, and Vietnam seem reluctant to relinquish control over the sector.

No government has yet contemplated introducing open access to transmission, though Malaysia is well placed to do so, with IPPs accounting for such a large share of its generating capacity. Nor has any country made much progress in setting up independent regulation and designing coherent pricing policies.

Market barriers

There are many barriers to achieving the full potential of power trade in the Greater Mekong subregion. The following are the most crucial.

Institutional and public policy

- **Leadership and priorities.** Only Lao PDR and Thailand rate cross-border trade highly. There is no authoritative regional group or agency to provide leadership in network development. Environmental issues must also be addressed at a regional level to resolve conflicts and ensure that no country bears an environmental burden so that others can have clean power. Failure to mitigate the environmental impact of dams will become a barrier to hydro development and thus a barrier to trade.
- **Laws, regulations, and contracts.** In every country laws, regulations, and power purchase contracts include long-term provisions

The lack of flexibility to reassign parts of the generation purchased under a long-term power purchase agreement will limit the scope for introducing more competition in the near term.

Transmission construction needs to be coordinated to minimize the cost of long-term investment—developing a robust market will require a network of facilities rather than point-to-point links.

that hamper the move to more competitive markets. For example, the lack of flexibility to reassign parts of the generation purchased under a long-term power purchase agreement will limit the scope for introducing more competition in the near term.

Where cross-border transmission is being developed, costs are bundled into a delivered capacity and energy price.

- **Transmission ownership.** Some governments have not yet decided which agency or entity will be responsible for building and operating transmission.
- **Open access rules.** Governments have not established open access rules for transmission facilities. Thus where private developers are building a transmission line to connect their plant to load-serving points, it is unclear whether a second generator could connect to this line. A need to construct additional transmission facilities could put a proposed project at a competitive disadvantage, particularly if the first plant added a unit at the existing site. There also is no policy allowing through-flows—required, for example, if Lao PDR were to permit sales from Vietnam to Thailand (though the Lao government has agreed in principle to allow output from China to be transported through its system into Thailand). Transmission facilities should be open to all generating plants on a nondiscriminatory basis.
- **Independent regulation.** The absence of independent regulatory agencies increases the risk for developers of arbitrary changes in tariffs.

Funding for power generation for export may be hampered by financiers' perception of risk related to country-specific issues or to the multinational character of projects.

Technical barriers

- **Network development.** Transmission construction needs to be coordinated to minimize the cost of long-term investment. There are plans to develop project-specific facilities to transmit output from one country to another. But developing a robust market will require a network of facilities rather than point-to-point links. A network would provide parallel facilities to ensure delivery of electricity in the event of outages.
- **Transmission protocol.** There is no protocol to govern the operation of a regional transmission network. If as a result one system constructs facilities to a standard lower than that of another, it could impose a reliability risk on the system with higher standards. Lack of a protocol also puts the reliability and quality of service at risk if operators in different countries are unsure about what procedures govern routine and emergency operations.

Commercial and financial barriers

- **Transparency of costs.** Whether trade develops will depend on the relative cost of power in neighboring countries. But comparing electricity rates in the region is extremely difficult because most currencies are nonconvertible, power suppliers do not separate generation and transmission costs, and accounting procedures vary.
- **Generation tariffs.** Generation dispatch decisions appear to be based on one-part energy tariffs. Yet dispatch decisions should be made by comparing generators' variable costs of production—information not provided by a one-part tariff. Only Thailand is moving toward a two-part tariff, however. An ap-

proach to pricing bulk electricity based on a one-part tariff acts as a barrier to economic trading both within a country and across borders.

- **Transmission tariffs.** The transmission tariff plays a key part in financing the creation and expansion of a transmission network. But no country has a separate transmission tariff. Instead, where cross-border transmission is being developed, costs are bundled into a delivered capacity and energy price at a remote point from the plant. Transmission tariffs have been defined only on a case-by-case basis.
- **Construction uncertainty.** Many plants for delivery of power to EGAT are in the planning stage, but there is much uncertainty about which will be built. This uncertainty has increased because the East Asian financial crisis may make it harder to raise finance for projects. Moreover, recent low bids for plants in Thailand threaten the viability of the least competitive hydro plants in Lao PDR. Uncertainty about which generation projects will be developed impedes sound decisions about transmission investments. And where governments have agreed to build and operate transmission facilities, there are doubts among generation developers about whether some of the facilities will be completed on time for the scheduled completion of generation projects.
- ***Country and cross-border risk.*** Funding for power generation for export may be hampered by financiers' perception of risk related to country-specific issues or to the multinational character of projects. The nature and degree of risks vary by country, but the most common are the financial weakness of buying utilities, currency nonconvertibility, government interference, breach of contracts or concession agreements, and the seller's possible lack of access to transmission lines. All these can undermine a project's financial viability and thus make financial closure more difficult. For many projects, official credits, loans, or guarantees may be needed to give comfort to commercial banks.

Future development of the power market

Developing an international power market in the Greater Mekong subregion will be a long-term process. Because of the long construction periods, most benefits will accrue after 2010. Thus while the current financial crisis may slow the process initially, it should not have a major impact on the overall benefits of developing international trade.

Market development is under way. Potential channels for regional cooperation have been established. The regional Electricity Power Forum (sponsored by the Asian Development Bank) provides governments an opportunity to discuss how to develop this cooperation. The Mekong River Commission has been conducting regional studies on the interconnection of the subregion's power systems. Under the umbrella of the Association of Southeast

BOX 3 PROPOSED MARKET DEVELOPMENT STRATEGY

- **Reach agreement to make power trade a high priority.**
- **Set up a regional coordinating body to establish a protocol for the new interconnected system and handle environmental issues.**
- ***In each country decide who will own and operate transmission and adopt regulations requiring nondiscriminatory open access.***
- **Ensure that domestic laws and regulations and long-term power purchase agreements are compatible with power trade.**
- **Develop a master plan for plant and transmission locations and get governments to commit to the transmission facilities.**
- **Develop an operating protocol to ensure safe, reliable, and efficient operation of the transmission system.**
- **Design a two-part tariff and a transmission tariff that will encourage investment in transmission facilities.**
- **Set stable tax and royalty policies for export.**

Asian Nations (ASEAN) governments have established a technical working group to coordinate interconnection efforts. And the World Bank has just completed a study to help promote power trade, assessing the potential benefits and proposing a strategy for developing a regional market (box 3). This strategy systematically addresses the barriers outlined in this text and will be discussed at a regional seminar scheduled for June 1998.

This Note is based on a World Bank–sponsored study, "Power Trade Strategy for the Greater Mekong Sub-region" (Report 17033-EAP, World Bank, East Asia and Pacific Region, January 1998).

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Reforming the Russian Electricity Sector

Margaret Wilson

In early 1997 the Russian government approved in principle the now common model of electricity sector reform: vertically separating generation, transmission, and distribution; introducing competition where possible; strengthening the regulation of functions less amenable to competition; and divesting government ownership. This model has been implemented in many countries, and the story of the reform would be relatively routine if not for special characteristics of the Russian power system: its size, diverse ownership, high level of nonpayments, and the combined heat and power role of many generating plants. This Note outlines the challenges posed by these characteristics and reports on reform achievements so far.

The first challenge to reform is the sheer size and scope of the network. The Russian power system consists of more than 200 gigawatts of generation capacity, most of it interconnected by 2.5 million kilometers of high-voltage transmission lines spanning an area only slightly smaller than the United States and Canada combined (table 1). Most of the generation capacity is thermal (70 percent), with hydro (20 percent) and nuclear (10 percent) making up the balance. Regionally, however, there are major differences. More than 50 percent of the hydro capacity is in Siberia and the far east, while 80 percent of the nuclear capacity is in the central (Moscow) and northwest regions.

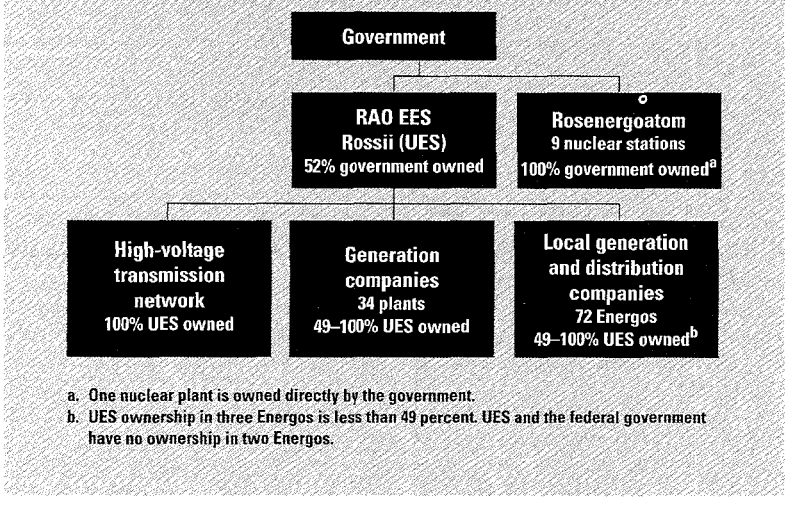
The regions jealously guard their hydro capacity. They regard it as a source of low-cost power for local industries and have little desire to see it blended into a national power supply. Moreover, the system was originally designed to provide a fairly high degree of regional self-sufficiency (transmission links between regions are often weak), and in many cases large parts of these self-sufficient regions are now in other countries. The main dispatch center for the northwest region, for example, was in Riga (now in Latvia), and one of the primary transmission lines from the central region to the Caucasus region passes through Ukraine.

TABLE 1 THE RUSSIAN ELECTRICITY SECTOR

Size	More than 200,000 megawatts.
Generation	827 billion kilowatt-hours (kWh) (1996).
Fuel mix	45% gas, 20% hydro, 18% coal, 10% nuclear, 7% oil.
Demand mix	50% industrial, 11% residential, 39% other (including services and agriculture).
Tariffs	Industrial: more than US$0.05/kWh, residential: US$0.02/kWh, with large regional differences.
Investment	Low, financed through cash flow. Almost no debt or external equity finance or private project development.
Collections	11% cash, 59% noncash, 30% unpaid.
Employees	921,000 (1996).

Note: Data are for 1997 except where otherwise specified.
Source: UES and Russian Federal Energy Commission.

FIGURE 1 OWNERSHIP STRUCTURE OF THE RUSSIAN ELECTRICITY SECTOR



a. One nuclear plant is owned directly by the government.
b. UES ownership in three Energos is less than 49 percent. UES and the federal government have no ownership in two Energos.

Consequently, restructuring generation to create a competitive market is not a straightforward process. Regional opposition, combined with serious risks that technical constraints will allow generators to game the system and extract monopoly prices, has led the government to adopt a cautious timetable for moving to a competitive market.

Diversified ownership

The second challenge lies in the electricity sector's ownership structure. While many countries began reform with a vertically integrated, state-owned monopoly, the Russian government in 1996 faced a sector that had already been partially restructured and privatized. Until 1992 the electricity sector had been organized in vertically integrated companies, called Energos, in each of the seventy-two oblasts or regions. But when mass privatization began that year, the federal government moved to maintain its control over the power sector.

The government formed a new company, RAO EES Rossii (commonly referred to as Unified Energy Systems, or UES), and gave it ownership of the country's largest hydro and thermal generating stations (nuclear excepted), the high-voltage transmission network, and the dispatch systems. The Energos were set up as separate companies to own and operate the smaller generating plants and the distribution networks, and some of their stock was sold to employees and managers under the voucher privatization program. UES retained at least a 49 percent interest in most of these new enterprises, however. The government also divested part of its holding in UES. It now owns about 52 percent of the shares, foreign companies hold about 28 percent, and Russian companies and individuals, including company employees and managers, own the balance (figure 1).

As a result of this decentralized ownership, the restructuring program requires the support of a wide range of stakeholders. The Energos in particular need to be persuaded of the benefits of change, since they own or manage more than 60 percent of installed capacity. The Energos regard the move to a competitive wholesale market as a threat to their autonomy, a change that will end their control over dispatch and oblige them to purchase high-cost power from the market rather than distributing low-cost power from their own plants. Some of the Energos understand that their power would be dispatched first and that they would receive the system marginal price for it. But they remain concerned about nonpayments on the wholesale market and about having to pay market service charges to sell and repurchase what they regard as their own power.

Outside shareholders of UES also will have to be persuaded of the merits of restructuring, particularly with regard to any divestiture of generation assets. While these shareholders would theoretically retain an equivalent ownership stake in newly formed generation companies, they might not perceive these holdings as equivalent in risks or returns to their existing holdings in an integrated UES.

Nonpayments

The third challenge is nonpayments. The root causes are many. They include tax avoidance, profiteering on barter settlements, legal and political barriers to cutting off supply to "strategic" customers, and simple failure by the government to collect adequate taxes or intro-

duce sufficient spending discipline to ensure that energy supplies to budget-funded agencies can be financed. The lack of cash payments has jeopardized the financial viability of many power sector enterprises, hampering their ability to introduce or maintain efficient operating systems or to respond to changing market conditions. Moreover, barter and other noncash instruments are an inefficient and costly basis for market transactions.

Restoring payment discipline is key to moving forward with the proposed restructuring and unbundling of the sector. Without this discipline, many of the newly formed enterprises would risk financial failure, which would both discredit the reforms and invite renewed government intervention. Nonpayments can be fully resolved only at the interface with the customer, however, which is typically through the regional distribution company. Thus the federal authorities cannot unilaterally address the problem, but must work through local entities.

Competition and regulation

The fourth challenge lies in the fact that many of the generation assets controlled by the Energos are combined heat and power plants. These plants were built primarily to meet local heating demands and are an integral part of the extensive district heating networks that in many large cities serve the majority of the population. In the absence of competitive heating markets, heat prices for these plants are regulated by local authorities, generally at a level equivalent to the cost of heat-only boilers. Regulators and municipalities are concerned about the integration of competitive and regulated activities in a single entity, about the implications of this under the current procedures for allocating joint and common costs, and about their ability to ensure that the Energos do not use the regulated heat market to extract windfall profits from electricity cogeneration. With the system of regional regulation still in its infancy and many of the local regulators lacking experience and expertise, this added complexity is a serious concern.

Achievements to date

Despite these challenges, the government has taken meaningful steps toward reforming and restructuring the electricity sector and has defined further steps as part of its 1998 program for economic reform. In 1997 the emphasis was on consolidation at the center, with the federal government strengthening its governance of the electricity sector and bringing new management into UES. The new management team has focused its initial efforts on restoring the company's financial viability. To this end,

- New financial controls and audit procedures were introduced. UES and ten of the Energos are being audited, and UES is moving to full IAS accounting.
- The investment program has been reviewed and rationalized, and funding withdrawn for about forty projects deemed nonviable.
- Collections have been improved, increasing cash payments to the UES transmission division by 250 percent and overall cash payments from 5 to 20 percent of revenues.
- New sources of capital are being explored, including private sector participation in planned new investment projects and a possible convertible bond issue for placement in international financial markets.

The government has also taken initial steps to introduce competition. It created an independent financial operator to establish a competitive wholesale market among large industrial customers and generators. Model contracts were established for transactions, using the network as a common carrier. Principles for access to the transmission and distribution networks and for regulation of wheeling tariffs are being established. A wholesale market, being piloted in one region, counted two generators and four customers among its participants by the end of the year. To participate, buyers must agree to pay cash, in advance, and to eliminate payment arrears. In return they receive a 35 percent discount on tariffs.

The government has also undertaken to reorganize generation, to boost operating efficiency

while laying a foundation for a competitive generation market. It has evaluated several restructuring options in recent months, and the 1998 program calls for finalizing and initiating the reorganization plan. Among the options is grouping the existing plants into generating companies, or Gencos, to create enough potentially viable, independent entities for a competitive market. Finally, the government has begun removing electricity pricing distortions, increasing tariffs to households by 32 percent and making a commitment to eliminate cross-subsidies by 2000.

Next steps

In 1998 reform efforts will be extended outward from the center, and pilots will be expanded to more regions. The four target areas of the 1998 program are increasing cash collections, improving dispatch of generators to lower average fuel costs, boosting operating efficiency, and reducing pricing distortions.

The government views financial viability of the sector, particularly increased liquidity, as key to the success of the reform. While UES more than tripled its cash collections in 1997, further improvements can be achieved only by resolving the nonpayment problem at the customer interface, that is, at the Energo level. Initial efforts in 1998 will be mainly diagnostic, though arrangements have been made for the private sector to run the commercial operations of one Energo under a management contract. Diagnostic efforts initially will focus on ten regions. Consultants will work with the Energos to identify the causes of the nonpayments in each region and test solutions. Actions to complement these initiatives will include increasing the electricity traded for cash on the wholesale market and improving payment discipline among budget-funded agencies.

Improving dispatch could save an estimated US$1 billion or more a year in fuel costs, and initial steps to realize these benefits will take place in 1998. UES, the federal regulatory agency, and consultants are developing an improved incentive system, including dispatching guidelines and procedures. New guidelines are to be in place in at least one zone (of seven) by the end of June. If the pilot efforts are successful, they will be extended to other zones.

The reorganization of generation, particularly the increased focus on competition among suppliers, is also expected to reduce electricity prices. As new generating plants begin to compete with existing plants, investment proposals are expected to become more rational and out-of-date, inefficient units are expected to close (plans for their closure are to be developed, including programs to mitigate social impacts).

Electricity prices still need to be adjusted to better reflect the economic cost of supply. Wholesale and industrial prices need to fall, and prices to households to rise. Efficiency improvements (in dispatch and operating practices) should help to bring down wholesale and industrial prices, as will rebalancing when household tariffs are increased. Improved access to investment financing is another potential source of tariff reductions. Because of limited access to capital markets, electricity tariffs currently incorporate full self-financing of new investments. But with improved financial viability, UES and the Energos should be able to attract debt financing for at least part of the investment program. That would allow prices to fall and would subject proposed investments to the discipline of review by the financial community.

Many problems remain to be resolved, and the commitment to reform periodically loses steam as pressing political issues arise. But on balance the Russian government has taken impressive steps toward creating a more efficient and effective electricity sector.

The World Bank has been a partner in the Russian electricity sector reform program for more than two years. It mobilized grant financing to help the government formulate the reform, provided technical assistance loans to support restructuring programs, and extended adjustment loans to encourage sustained commitment to reform.

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Tapping International Equity Markets through Depository Receipts

Lessons from the telecoms sector

Mohammad A. Mustafa and Carsten Fink

Although international offerings are now a well-established privatization route for telecommunications companies (in addition to local offerings and sale to a strategic partner) and governments have raised billions of dollars using this method, some governments of emerging economies still fail to give it serious attention. The main advantages of international offerings stem from the greater market depth and liquidity provided by international capital markets: telecommunications companies are sometimes too big for local markets to absorb, and more active trading attracts a wider shareholder base, implies continuous evaluation of a company's value, and increases management's accountability for a company's financial performance. International offerings also enhance the legitimacy of shares being offered because companies must comply with transparent accounting rules and strict disclosure standards in the host market. This Note outlines the offer process and implementation risks.

When companies make a public offering in a market other than their home market, they must launch a depository receipt program.[1] Depository receipts represent shares of a company held in a depository in the issuing company's country. They are quoted in the host country's currency and treated in the same way as host country shares for clearance, settlement, transfer, and ownership purposes. These features make it easier for international investors to evaluate the shares than if they were traded in the issuer's home market. They also enable international investors to invest in foreign companies with low transactions costs and without the tax and paperwork complications of acquiring foreign stock.

Types of depository receipts

Issuing companies have a choice of several types of publicly traded depository receipts. Global depository receipts (GDRs) are usually traded on major international exchanges outside the United States—mainly the London Stock Exchange (LSE)—and in the U.S. over-the-counter market. A company issuing GDRs does not have to comply with U.S. Generally Accepted Accounting Principles (GAAP) or full disclosure requirements of the U.S. Securities and Exchange Commission (SEC). Thus, GDR programs allow companies to enjoy the benefits of an internationally traded security without changing their reporting practices. Companies that wish to offer their securities to U.S. institutional investors and list their shares on a U.S. stock exchange use American depository receipts (ADRs), which usually require adherence to U.S. GAAP and more stringent SEC disclosure requirements. Both GDRs and ADRs must also meet the listing requirements of the exchange on which they are traded.

A company can also access the U.S. market through a private placement of depository

receipts, under SEC Rule 144a. So-called Rule 144a depository receipts, which trade only among large U.S. institutional investors, can be used to raise capital in the U.S. market without extensive disclosure, because the issuing company does not need to register with the SEC. Offerings of GDRs outside the United States are usually combined with Rule 144a depository receipts.

The choice of type of depository receipts and of the international markets to access depends on the related disclosure and reporting standards and, if the securities are to be listed, on the requirements of the stock exchange. Although ADRs usually offer higher visibility and attractiveness compared to GDRs, they require higher standards of disclosure. Other factors influencing the choice include the potential demand from investors and the objectives of the offering.

Process

An offering of depository receipts usually starts with the appointment of a financial adviser—a financial institution such as an international investment bank—to manage the process. The adviser sets the number of shares to be represented by one depository receipt—that is, the depository receipt ratio (when the Chilean telephone company Compañía Telecomunicaciones de Chile, or CTC, issued depository receipts, for example, each one represented seventeen common shares). The ratio is set so that the price of a depository receipt is comparable to that of similar securities in international markets. The adviser also appoints a depository bank in the host market and a custodian bank in the country of the issuer. The depository bank has responsibilities relating to shareholder rights (such as payment of dividends and voting at shareholder meetings), which are stated in the depository receipt certificate, and must also maintain a share register of depository receipt owners.

The issuing company determines the number of shares to be sold in the international market and delivers the shares to the custodian bank. The custodian registers these shares in the name of the depository bank, which issues the appropriate number of depository receipts and delivers them to the members of the underwriting syndicate. Trading then begins. Although depository receipts are traded exclusively in the host market, continuous arbitrage between the host market and the issuer's home market tends to minimize the price differential between the two markets.

Depository receipt issues are usually marketed through a book-building route, an offering method that leads to efficient price discovery. Typically the lead manager, or book runner, builds the order book by forming a syndicate that fans out on a marketing run among institutional investors. The price and size of the issue are determined on the basis of both an in-house valuation of the issuing company's intrinsic worth and the bids received. Because depository receipts trade mainly among large institutional investors, shares can be sold in bulk and thus quickly and cheaply.

A useful advantage of depository receipt offerings is that the question of foreign ownership is addressed when the shares are first registered in the name of the depository institution. This is of special importance in emerging markets, where foreign equity investment is often restricted.

Implementation risks—lessons from Indian issues

Ongoing privatization and financial liberalization in emerging economies have led to continuous growth in the number of depository receipt offerings from these countries (table 1). The amount raised and the equity share sold vary depending on the size of the company, the privatization strategy, and financial market conditions. Asian and Latin American companies have been the biggest source of offerings.

India, which has heavily relied on depository receipts as a method of introducing private ownership, has been one of the largest issuers of these securities among emerging markets, raising more than US$4 billion in capital since

TABLE 1 SELECTED ISSUES OF DEPOSITORY RECEIPTS BY TELECOMMUNICATIONS COMPANIES IN EMERGING ECONOMIES

Company	Year	Type of depository receipt	Amount raised (millions of U.S. dollars)	Depository receipts as a percentage of company equity	Stock exchange
VSNL (India)	1997	GDR	448	17[a]	LSE
MTNL (India)	1997	GDR	360	10[a]	LSE
BPL Cellular Holdings (India)	1997	ADR	100	11[a]	NASDAQ
SK Telecom (Republic of Korea)	1997	ADR	100	..	NYSE, LSE
CANTV (Venezuela)	1996	ADR	1,200	41[a]	NYSE
PT Telecomunikasi (Indonesia)	1995	ADR	540	7	NYSE, LSE
Pakistan Telecommunications Corporation	1994	GDR	898	10[a]	LSE
PT Indosat (Indonesia)	1994	ADR	873	25	NYSE
Telmex (Mexico)	1991	ADR	2,200	15	NYSE
CTC (Chile)	1990	ADR	100	12	NYSE

.. Not available.
a. Estimated.
Source: Company reports and newspaper articles.

1992. In 1997 alone Indian telecommunications companies raised more than US$1 billion in depository receipt offerings. GDR issues by two state-controlled telecommunications companies —Mahangar Telephone Nigam Ltd. (MTNL) and Videsh Sanchar Nigam Ltd. (VSNL)—accounted for more than 80 percent of this amount.

Until recently all Indian issues were GDRs that traded on the LSE, and most included Rule 144a depository receipts. Indian companies have been kept away from the lucrative U.S. market and listings on the New York Stock Exchange (NYSE) and NASDAQ by stringent disclosure requirements, higher listing costs, and more transparent accounting standards that put dubious corporate governance practices under scrutiny. But in May 1997 BPL Cellular Holdings issued US$100 million worth of ADRs, becoming the first Indian company to be listed on NASDAQ. Three more companies—Bharti Cellular, JT Mobile, and Infosys Technologies—are planning depository receipt issues in the U.S. market.

Still, some of the Indian issues have been problematic, and the experience shows what can go wrong if an issue is not carefully designed.

BPL Cellular Holdings

BPL Cellular Holdings, which includes US West as a joint venture partner, operates greenfield cellular services in three telecommunications circles in India: Kerala, Maharashtra, and Tamil Nadu. Its successful ADR issue followed a failed attempt in December 1996, an issue pulled out only hours before it went on offer. At a share price of US$16, this initial public offering was expected to raise US$200 million by selling 12.5 million shares, 22.3 percent of the company's equity.

Where did the ADR offer go wrong? Market analysts have cited several reasons for the failure. First, the issue price, initially US$16 a share, seemed unjustifiably high to most investors. The lead underwriters found few takers, even after deferring the issue twice and reducing the price to US$12 and then to US$10. The discounts, unusual in the ADR market, made investors even more wary of the offering.

Second, investors prefer mature companies to new ventures that are about to take off. Several potential investors made their preferences known by not attending the road show. A better

route for start-up companies is to first establish a network, invest the company's own funds, and then approach international markets.

Third, the offering was poorly timed. Several telecommunications issues were offered in the same period, including a US$1.2 billion issue from Venezuela's CANTV, a US$450 million issue from Russia's Vimpel Communications, and a US$12 billion issue from Germany's Deutsche Telekom. The offering by BPL Cellular Holdings fared poorly relative to those of the other telecommunications companies. Investors' general cautiousness toward Indian equity issues at the time of the offering may also have influenced U.S. investors' judgment.

Fourth, potential investors were concerned about the financial health of BPL Cellular Holdings. The ADR offering document indicated negative net worth, large liabilities, and operating losses of US$117 million in the year of the offering. The document also contained qualifications by the company's independent international auditors.

Finally, the absence of an independent regulatory agency at the time of the offering was another reason cited for the failed ADR. When BPL Cellular Holdings concluded its successful US$100 million ADR issue in May 1997, the Telecommunications Regulatory Authority of India had just been established.

VSNL

Another success that followed a failure is the GDR issue by VSNL, the exclusive provider of international telecommunications services in India. After two failed attempts in 1994, VSNL successfully issued India's largest-ever GDR offering in March 1997, raising about US$448 million. The issue was listed on the LSE and was several times oversubscribed. It reduced the government's ownership in VSNL to 65 percent (15 percent of VSNL's equity is owned by Indian institutional investors).

Why did VSNL's 1997 GDR issue succeed? First, there was better balance in demand forecasting and marketing between the U.S. market and the European and Asian markets. Two road show teams circled the world twice in marketing the issue, attracting about 650 institutional investors from twenty-eight countries to the offering.

Second, with unrealistic pricing cited as the main reason for the previous failed attempts, the government had by then realized that it could not dictate the share price. It instead adopted the market-driven book-building approach to price the issue.

Finally, changes in investor sentiment toward Indian equity issues and India's improved economic fundamentals favored VSNL's offer. A prudent government budget further boosted investor confidence before the offering.

Conclusion

Depository receipts offer a well-established route for telecommunications companies in emerging economies to access foreign capital markets. And they help improve corporate governance in these companies by increasing accountability and upgrading financial accounting standards. But experience has shown that to guard against failure of a depository receipt issue, much effort needs to be put into choosing the right type of depository receipts, marketing the issue, forecasting investor demand, and determining the share price. Issuers cannot control all the conditions, however. The health of financial markets, the sector's regulatory environment, and the overall economic and political risk of the issuer's home country influence the perceptions of international investors and thus the success of an international public offering through depository receipts.

[1] The New York Stock Exchange is launching an initiative to allow companies to list directly.

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