United States International Trade Commission

Natural Gas Services:

Recent Reforms in Selected Markets

Investigation No. 332-426
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U.S. International Trade Commission

This report was prepared principally by the Office of Industries

Division Chief
Richard W. Brown

Project Leader
Christopher Melly
cmelly@usitc.gov

Deputy Project Leader
Joann Tortorice

Economist
Soamiely Andriamananjara

Staff Assigned
Tsedale Assefa, Jennifer Baumert, Laura Bloodgood, William Chadwick
David Ingersoll, Dennis Luther, Mike Nunes, and Ryan Schroeder

With special assistance from
Christi Collins and Cynthia Payne

Address all communications to
Secretary to the Commission
United States International Trade Commission
Washington, DC 20436

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Natural Gas Services: Recent Reforms in Selected Markets

Investigation No. 332-426

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ABSTRACT

Following receipt on January 16, 2001, of a request from the United States Trade Representative (USTR) (see appendix A), the U.S. International Trade Commission (USITC) instituted investigation No. 332-426, *Natural Gas Services: Recent Reforms in Selected Markets*, under section 332(g) of the Tariff Act of 1930 (19 U.S.C. 1332(g)). As requested by the USTR, this report provides (1) a description of the nature of reform, including, but not limited to the extent of privatization, vertical and horizontal restructuring, and consumer choice, as applicable; (2) an examination of current market access conditions, including, but not limited to measures affecting network access, investment, and trading (i.e., the exchange of natural gas contracts through financial markets), as applicable; and (3) a review of common regulatory practices adopted by multiple countries, insofar as they exist. Copies of the notice of the investigation were posted in the Office of the Secretary, U.S. International Trade Commission, Washington, D.C. 20436, and the notice was published in the *Federal Register* (Vol. 66, No. 33) on February 16, 2001 (see appendix B). In addition, interested parties were invited to submit written statements concerning the investigation. A public hearing was scheduled for April 3, 2001, but subsequently canceled because no parties submitted a request to appear.

As requested, this report focuses on the downstream natural gas market, including transmission, distribution, and marketing activities in specific countries. The countries examined are Argentina, Australia, Brazil, Canada, Japan, the Republic of Korea (hereafter referred to as "Korea"), Mexico, Spain, and the United Kingdom. For each of these countries, this report summarizes the nature of reform and examines current market conditions. The report ultimately concludes by identifying common regulatory practices and impediments to competitive market development, and by analyzing the implications of regulatory reform for international trade in services.

The findings of this report reveal that, despite considerable variation in the circumstances faced by each country, the reform programs undertaken are broadly comparable with one another. By encouraging private participation, limiting market power, and guaranteeing nondiscriminatory access to common facilities, these programs strive to create an environment conducive to new market entrants and vibrant competition. The result of reform can be seen in the expansion of customer choice and the development of trading markets for natural gas, transportation capacity, and financial instruments.

At the international level, regulatory reform creates new opportunities for private firms to invest abroad in the natural gas transmission, distribution, and marketing sectors. In regions where natural gas markets transcend national frontiers, such as Europe, South America, and North America, private firms may also have new opportunities to provide marketing, risk management, and related services on a cross-border basis. In trade terms, these new business prospects constitute new market access opportunities, which means that regulatory reform directly fosters growth of international trade in services.

Although reform programs have generally succeeded in introducing competition into the segments of the natural gas industry where it is most feasible (production and marketing), controlling the market power of incumbent service providers and implementing effective, nondiscriminatory third-party access to pipelines have proven to be enduring problems. Despite these impediments, the prevailing trends appear to suggest that the market for natural gas will continue to expand globally and that the competitive market model will be adopted by a progressively larger group of countries. As a consequence, international trade in natural gas services will likely continue to expand, leading to increased relevance for trade rules such as those contained in the General Agreement on Trade in Services.

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EXECUTIVE SUMMARY

Introduction

- On January 16, 2001, the United States Trade Representative (USTR) requested that the United States International Trade Commission (USITC) conduct an investigation into recent natural gas market reforms undertaken in selected countries. USTR initiated this request in the context of ongoing trade negotiations at the World Trade Organization (WTO) under the General Agreement on Trade in Services (GATS). In its request, USTR observed that regulatory reform of the natural gas sector is likely to have a significant impact on market access opportunities and the competitive position of U.S. firms. As a result, the effects of regulatory reform on international trade in services may have bearing on services trade negotiations at the WTO.

- As requested, this report focuses on the downstream natural gas market, including transmission, distribution, and marketing activities in specific countries. The countries examined are Argentina, Australia, Brazil, Canada, Japan, the Republic of Korea (hereafter referred to as "Korea"), Mexico, Spain, and the United Kingdom. For each of these countries, this report summarizes the nature of reform and examines current market conditions. The report concludes by identifying common regulatory practices and impediments to competitive market development, and by relating the implications of regulatory reform to international trade in services.

Nature of Reform

- Regulatory reform of the natural gas industry essentially entails introducing competition into segments where it is feasible to do so, in order to achieve greater economic efficiency and thereby reduce prices. Of the four distinct market segments in the natural gas industry (production, transmission, distribution, and marketing), competition appears to be most feasible in the production and marketing segments, and least feasible in the transmission and distribution segments.

- To introduce competition, governments must remove or loosen regulatory control over prices and must implement a range of policies to encourage the entrance of new competitors. Reform policy measures may be viewed as having three components: 1) private-sector participation; 2) structural reform, including vertical and horizontal unbundling; and 3) open, or third-party access, to pipeline networks and other essential facilities. The implementation of these policies usually involves an iterative process whereby legislation and regulations are progressively refined as the market develops.

- These reforms enable new private firms to enter the market by constraining the market power of incumbent service providers and creating conditions that foster competition in all segments where it is feasible.

Current Market Conditions

- All of the subject countries are pursuing policies that will permit private participation in the marketing segment, and all but those facing constitutional constraints are moving to permit private participation in the production and importing segment.

- In the transmission and distribution segments, which will continue to function as regulated monopolies, all countries have similarly signaled movement toward private participation. This appears to be of particular importance for countries where private investment in infrastructure development is necessary to support the growth of a market for natural gas.

- With the exception of Brazil, Japan, and Korea, all of the subject countries have implemented some form of vertical restructuring. In most cases, this involves requiring incumbent service providers to separate, or unbundle, their financial accounts for monopoly activities (transmission and distribution) from those for competitive activities (production and marketing). A few countries (Argentina, Canada, and the United Kingdom) have gone so far as to require full ownership separation in some situations – the most definitive way to remove incentives for cross-subsidization or other anticompetive practices.

- Horizontal restructuring has also proven to be necessary in several countries. This entails fragmentation of incumbent firms within a potentially competitive market segment to reduce their market power. This has been accomplished through various means, such as selling portions of a firm during privatization, auctioning concessions for some of the assets of the dominant firm, or other legal or regulatory action.

- With the exception of Korea, which is still formulating its policy, all of the subject countries have developed a third-party access regime by developing rules that require access by market participants to essential common infrastructure. These rules essentially require the owner of the facility to permit others to gain access at reasonable rates and through fair and transparent procedures. In most cases, the government actively intervenes and regulates the rates that may be charged for transmission and distribution services. However, an alternative approach is to permit transmission and distribution providers to negotiate with those who would like to use their facility, subject to oversight by government regulators.

- As a result of the reform programs, some degree of competition is now possible in all of the subject markets except for Brazil and Korea. Competition has generally been phased in by permitting marketers, who may be producers, distribution companies, or pure intermediaries, to compete to sell to only large industrial consumers and other marketers in the initial stages. Over time, some countries have extended competition to progressively smaller consumers. Australia, Canada, and the United Kingdom have gone furthest by extending competition and customer choice to all classes of consumers.

- As a competitive market evolves, market participants increasingly need to buy, sell, and trade contracts for natural gas and transportation capacity in order to match supply with demand and manage risk. Most of these transactions take place informally through bilateral negotiations. However, as trading volume increases, transactions may gravitate toward centralized exchanges. Among the subject countries, centralized exchanges have developed only in Australia, Canada, and the United Kingdom.

- Although making a determination of the effects of regulatory reform on prices and service availability is a challenge that lies beyond the scope of this study, some anecdotal information is available for a few of the countries examined in this report. For example, in the state of Victoria, Australia, where there is competition among marketers but limited competition among upstream producers, natural gas prices declined after reforms were implemented, by the relatively modest rates of 2 percent, 4 percent, and 7 percent for the industrial, commercial, and residential segments, respectively. In the city of Sao Paulo, Brazil, where privatization is the only reform that has taken place, natural gas sales have increased by 70 percent since private investors gained control of and subsequently expanded the distribution network. In the United Kingdom, where competitive markets are highly advanced, nearly 60 firms have entered the marketing segment by obtaining supply licenses. The average price in real terms paid by industrial, commercial, and residential consumers declined by 20 percent, 30 percent, and 20 percent, respectively, from 1990 to 2000. It should be noted, however, that the extent to which the introduction of competition is responsible for these price changes as compared with other factors like technological advances, weather patterns, or the pricing of alternative fuels has not been determined.

Impediments to Competitive Market Development

- Although regulatory reform programs have made considerable progress toward introducing competition into the natural gas industry, some impediments remain. In particular, these impediments arise from difficulties in bringing about effective structural reform and in guaranteeing third-party access.

- Problems related to inadequate horizontal restructuring have arisen in both the production and marketing segments, as incumbent firms reportedly continue to exercise market power as a result of holding a dominant market position. Problems have also arisen with respect to vertical restructuring as some countries have not yet achieved fully effective separation of monopoly functions from competitive activities. These factors have contributed to ongoing concerns that cross-subsidization and abuse of market power by incumbent service providers may deter new market entrants and so impede competition.

- With respect to guaranteeing third-party access, the principal problems appear to concern the transparency and effectiveness of access rules. In various countries, these rules have been characterized as unclear, non transparent, or too narrow in scope. As a result, new market entrants may have difficulty accessing facilities which are essential to serving their customers.

- Physical constraints may also present impediments to competitive market development. Inadequate pipeline infrastructure presents a limitation on available capacity, which in turn may prevent new entrants from purchasing sufficient capacity to serve new customers. Similarly, geographic factors that make construction of pipelines prohibitively expensive result in market fragmentation and prevent nationwide competition.

- One interesting aspect of the impediments identified by industry representatives is that there are relatively few that are directed specifically at foreign firms. The general uniformity of treatment between foreign and domestic firms may be explained by the fact that regulatory reform programs are essentially intended to facilitate entry by any and all potential new market participants. In some cases, investment from foreign firms may even be an essential element to support competitive market development. Consequently, imposing impediments selectively on foreign firms would appear to be counterproductive.

Implications for International Trade in Services

- The natural gas industry is becoming increasingly global, which presents several clear implications for international trade in services. Regulatory reform creates new opportunities for private firms to invest internationally in the natural gas transmission, distribution, and marketing sectors. In regions where natural gas markets transcend national frontiers, such as Europe, South America, and North America, private firms may also have new opportunities to provide marketing, risk management, and related services on a cross-border basis. In trade terms, these new business prospects constitute new market access opportunities, which means that regulatory reform directly fosters growth of international trade in services.

- Since regulatory reform affects international trade in services, it appears logical to consider the relationship between reform and international trade agreements. The most relevant agreement appears to be the General Agreement on Trade in Services (GATS) of the World Trade Organization (WTO). When the GATS entered into effect in 1995, it included a built-in agenda to pursue progressive rounds of liberalization. In accordance with this provision, WTO members initiated a new round of GATS negotiations on January 1, 2000, with the objective of expanding trade and thereby promoting global economic growth.

- Given this objective and the effect of regulatory reform on trade, it would seem to be consistent to conclude that the 141 signatories to the GATS could have an interest in supporting and encouraging regulatory reform. However, because regulatory reform represents a major domestic policy initiative, the extent to which an international agreement can influence the process may be limited.

- The GATS may, however, be an effective instrument for supporting reform programs after they have been implemented. Regulatory reform programs essentially facilitate market entry by any and all potential participants. The optimal pool of potential new entrants is as large as possible and includes foreign participation. But foreign firms often face increased risk as indigenous firms may have better access to and more influence over the local regulatory, political, and judicial systems. International commitments to a set of principles concerning foreign participation, such as those contained in the GATS, can help mitigate this risk by providing assurance that foreign firms will be treated in a nondiscriminatory manner. In addition, recourse to the WTO dispute settlement mechanism may afford greater credibility to the reform programs and regulatory authorities of countries that undertake commitments pertaining to natural gas services.

- WTO members have already made some commitments under the GATS that are relevant to natural gas services. However, there are two important open questions concerning the scope of existing GATS commitments that create considerable uncertainty for both businesses and governments. First, the existing industry classification may not adequately describe natural gas services and thus may create confusion concerning the coverage of specific commitments on market access and national treatment. Second, existing GATS obligations may not provide sufficient guarantees of *effective* market access in a competitive natural gas industry, primarily because these obligations do not address issues concerning access and use of essential network facilities.

Conclusion

- Despite considerable variation in the circumstances faced by the countries examined in this report, the reform programs undertaken are broadly compatible with one another. By encouraging private participation, limiting market power, and guaranteeing nondiscriminatory access to common facilities, these programs strive to create an environment conducive to new market entrants and vibrant competition. The result of reform can be seen in the expansion of customer choice and the development of trading markets for natural gas, transportation capacity, and related financial instruments.

- Although the implementation of reform programs have generally succeeded in introducing competition into segments of the natural gas industry where it is most feasible, controlling the market power of incumbent service providers and implementing effective, nondiscriminatory third-party access to pipelines have proven to be enduring problems. Despite these impediments, the prevailing trends appear to suggest that the market for natural gas will likely continue to expand globally and that the competitive market model will be adopted by a progressively larger group of countries. As a consequence, international trade in natural gas services will continue to expand, leading to increased relevance for trade rules such as those contained in the GATS.

GLOSSARY OF TERMS

Balancing	Making pipeline receipts and deliveries of gas equal. Balancing may be accomplished daily, monthly or seasonally, with penalties generally assessed to firms responsible for excessive imbalance.
British thermal unit (btu)	A unit measurement of heat equivalent to 1055 joules. (See also joule.)
Bundled rates	Gas rates that reflect both the commodity price, and transmission and distribution tariffs.
Capacity market	A market in which contracts for pipeline capacity are re-sold to third parties, such as retail suppliers or large end-users.
Captive customer	A customer who is not free to choose his or her own natural gas supplier. Captive customers are also referred to as non-eligible or non-contestable customers.
Collar	A financial instrument that protects the holder from a decline in stock price and also provides him the opportunity to make a profit if the stock price increases.
Concession	The right granted by a government to a private-sector entity for a specified period of time to, for example, develop natural gas reserves or operate a pipeline.
Contestability	The ability of suppliers to compete for eligible customers.
Cost-plus	A type of regulation in which transmission tariffs are set to allow pipeline companies to recoup operating costs plus a pre-determined rate of return on investment. (See also rate-of-return.)
Distribution	The movement of natural gas through low-pressure or medium-pressure pipelines to customers, or end-users.
Financial contracts market	The trading of standardized futures and options contracts through a centralized exchange.
Flaring	Burning of gas for the purpose of safe disposal.
Futures contract	A contract in which the seller (or buyer) commits to sell (or purchase) a certain amount of gas at a specified price to be determined on or before a specific date in the future. These contracts are tracked in exchanges.
Gathering	The process of operating extensive low-pressure gas lines in order to aggregate the production of several separate gas wells into one larger receipt point for delivery into a transmission pipeline.

Hub	A geographical location where multiple buyers and sellers trade natural gas for physical delivery.
Interconnection	A form of third-party, or open access, in which an entity is permitted to connect its pipeline to one that already exists. (See also third-party access.)
Joule	A unit of energy required to move a force equivalent to 1 newton for 1 meter.
Liquefication	The process of condensing natural gas into liquid form.
Liquefied natural gas (LNG)	Natural gas that has been cooled to a temperature of -160 degrees celsius, and whose volume is reduced to about one-sixth that of natural gas in vaporized form.
Liquefied petroleum gas (LPG)	Also known as propane, liquefied petroleum gas (LPG) becomes vapor at -44 degrees celsius. It is stored and transported in tankers.
LNG storage facility	Large tanks, sometimes located underground, used to store gas in liquid form.
LNG tanker	An oceangoing ship designed to transport liquefied natural gas.
LNG terminal	A facility used to regasify, or convert liquefied natural gas into vapor form. (See regasification.)
Local distribution company (LDC)	A pipeline distribution company that usually serves an exclusive area, at either the municipal or regional level.
Marketer	Any entity that trades natural gas bilaterally, or through a centralized exchange, and/or that sells it to end-users. Producers, distributors, retail suppliers, and traders may all function as marketers.
Million cubic meters (mcm)	A unit measurement of gas volume. The corresponding abbreviations for billion cubic meters and trillion cubic meters are bcm and tcm, respectively.
Open access	See third-party access.
Options contract	A contract that gives the seller (or buyer) a right to sell (or purchase) a certain amount of gas during a specified time period at a specified price. The seller (or buyer) is not contractually obliged to exercise the option.
Over-the-counter (OTC) market	A market where transactions are negotiated directly between buyers and sellers rather than through a centralized exchange.
Pipeline capacity	The volume of natural gas that can be transported through a pipeline over a specified period of time.

Pipeline tariff	A price charged by an owner of a pipeline or pipeline network to third-party users of its facilities.
Price cap regulation	A type of tariff regulation in which the regulator determines a ceiling on transportation tariffs and the rate of return is not limited.
Primary gas market	A market in which natural gas is sold by suppliers to their customers through bilateral transactions, and which includes the physical delivery of gas. Primary gas market transactions are often executed through take-or-pay contracts. (See also take-or-pay contract.)
Rate-of-return regulation	A type of tariff regulation in which transportation tariffs are set to allow pipeline companies to recover an established profit margin over and above the costs of operating pipelines. (See also cost-plus.)
Regasification	The process of converting liquefied natural gas into vapor form.
Retail supply	The sale of natural gas to a customer, or end-user, through the primary gas market.
Secondary gas market	A market in which gas is traded through short-term contracts between primary gas market customers and third parties.
Spot market	A market in which traders buy and sell a commodity for immediate delivery. Spot market transactions can occur on a bilateral basis (i.e., one-on-one between a buyer and a seller) or through a centralized exchange.
Swaps	An agreement to exchange future cash flows (e.g., fixed-for-floating).
Take-or-pay contracts	A contract in which the buyer agrees to pay the supplier for a certain volume of gas to be delivered over a specific time period, even if the buyer does not use the full amount of gas that is delivered.
Transmission	The transport of gas through high-pressure pipelines across large distances to distribution networks or to large end-users.
Transportation	The movement of gas through transmission and distribution networks.
Third-party access (TPA)	A mechanism that requires the owner of transmission and distribution pipelines to allow third parties to access such pipelines for the purpose of gas supply on a fee basis. Third-party access may also be referred to as open access.
Unbundling (ring fencing)	The separation of a vertically integrated gas utility into discrete operating units (e.g., those that oversee import/production, transportation/storage, and supply/trading) for the purpose of introducing competition into the market.
Wheeling	The movement of gas through a transportation pipeline network.

CHAPTER 1
INTRODUCTION

Objective and Scope

Following receipt of a request on January 16, 2001, from the United States Trade Representative (USTR) (see appendix A), the United States International Trade Commission (USITC or the Commission) initiated a fact-finding investigation into the nature of regulatory and market reforms in the natural gas industry. USTR initiated this request in the context of ongoing trade negotiations at the World Trade Organization (WTO) under the General Agreement on Trade in Services (GATS). In its request, USTR observed that regulatory reform of the natural gas sector is likely to have a significant impact on market access opportunities and the competitive position of U.S. firms. As a result, the effects of regulatory reform on international trade in services may merit consideration in services trade negotiations at the WTO. USTR requested that the findings of this investigation be presented publicly in order to provide helpful background information to support trade negotiators from all WTO members.

As specified by USTR, this study focuses on the downstream natural gas market, including the following segments: transmission (including transport and storage); distribution; wholesale and retail supply; and trading. Production and importing activities are covered to a limited extent in order to provide necessary contextual information. In the course of research, USITC staff found that the activities described by wholesale supply, retail supply, and trading may often be effectively characterized by the single term "marketing."[1] Consequently, this report frequently refers to natural gas marketing as a simple convention for describing sales and trading of physical and financial contracts for natural gas.

The country markets examined in this study were specified by USTR in order to provide insight into a range of experiences where significant market reform, privatization, and liberalization have occurred or are ongoing. The markets selected are: Argentina, Australia, Brazil, Canada, Japan, the Republic of Korea (hereafter referred to as "Korea"), Mexico, Spain, and the United Kingdom. As a group, these countries represent 16 percent of global natural gas consumption (table 1-1). As requested, this report (1) presents a description of the nature of reform, including, but not limited to the extent of privatization, vertical and horizontal restructuring, and consumer choice, as applicable; (2) examines current market access conditions,

[1] In many markets, there is no distinction between wholesale supply and retail supply, but distinctions are made based upon the volume of natural gas purchased. The term "marketing" then captures both activities. Also, virtually all market participants may be engaged in trading, and regulatory systems do not appear to contain a distinction between trading and marketing.

Table 1-1
Selected market characteristics, by country, 1999

	Production	Consumption	Share of total world consumption	Imports	Exports	Natural gas: Share of total energy consumption	Reserves	Share of total world reserves
	—Million cubic meters—		*Percent*	*Million cubic meters*		*Percent*	*Million cubic meters*	*Percent*
Argentina	38,981	36,522	1.53	947	3,548	45.8	686,000	0.47
Australia	31,243	21,607	0.91	0	9,636	16.4	1,263,000	0.87
Brazil	6,085	6,484	0.27	[1]0	[1]0	2.8	226,000	0.15
Canada	176,797	83,541	3.50	807	94,687	28.9	1,808,000	1.24
European Union (total)	233,743	393,691	16.51	226,845	([2])	([2])	([2])	([2])
Spain	143	14,550	0.61	15,222	0	11.2	2,000	0.00
United Kingdom	104,958	97,292	4.08	1,130	7,767	36.4	755,000	0.52
Japan	2,280	74,915	3.14	72,151	0	12.0	40,000	0.03
Korea	0	16,838	0.71	16,491	0	8.4	([2])	([2])
Mexico	36,442	35,741	1.50	1,650	1,382	20.8	851,000	0.58
United States	531,054	605,358	25.39	100,463	4,733	23.3	4,642,000	3.19
World	2,420,708	2,384,355	100.00	600,795	606,107	22.8	145,723,000	100.0

[1] Data presented are from 1998. Brazilian imports are likely to increase significantly as a result of the Bolivia-to-Brazil pipeline, which began operations in July 1999.
[2] Not available.

Source: U.S. Department of Energy (USDOE), Energy Information Administration (IEA), *International Energy Annual 1999*, tables 4-2, E-1, and E-3; and USDOE, IEA, *Country Analysis Briefs* found at Internet address *http://www.eia.doe.gov*, retrieved Mar. 19, 2001.

including, but not limited to measures affecting network access, investment, and trading (i.e., the exchange of natural gas contracts through financial markets), as applicable; and (3) identifies common regulatory practices adopted by multiple countries, insofar as they exist.

This letter follows a similar request made by the USTR in November 1999 for the Commission to conduct an investigation of electric power markets in Argentina, Australia, Brazil, Canada, Chile, the European Union, Japan, New Zealand, and Venezuela. The Commission submitted the findings of this investigation in its report entitled *Electric Power Services: Recent Reforms in Selected Foreign Markets* (USITC publication 3370), to the USTR on November 23, 2000.[2]

Background Information

The GATS, one of the Uruguay Round agreements, broke new ground as the first international agreement to apply to trade in service industries. In addition, since the GATS includes the provision of services through a commercial presence in its definition of services trade, the treaty also became the first multilateral, legally enforceable agreement to cover the right of establishment through foreign direct investment.

However, the successful conclusion of the GATS in 1994 represented only one step toward achieving full liberalization of international trade in services, as many countries were unable or unwilling to open their markets completely. For some, opening markets to participation by foreign firms involved making regulatory, legislative, and even constitutional changes that would take considerable time to implement. Others may have declined to liberalize due to political pressure from special interest groups, or out of concern that foreign competition might adversely affect domestic firms. Still others may have delayed liberalization to gain bargaining leverage. Regardless of the reasons, negotiators recognized that full services trade liberalization would be a lengthy, incremental process, and so built into the agreement provisions requiring successive rounds of negotiations. In accordance with these provisions, WTO members began a new round of services trade negotiations in January 2000.

These renewed negotiations are intended to broaden and deepen the coverage of GATS obligations by extending the scope of the agreement to a wider range of industries and eliciting stronger commitments from WTO members. Energy services figure prominently among industries that may benefit from more thorough coverage under the GATS. Presently, the coverage of energy services is not clearly defined under the GATS, which means the GATS does little to foster international trade in such services. This lack of clarity concerning the coverage of the GATS is of increasing concern as technological advancements, privatization programs, and regulatory reforms have

[2] Copies of this report may be obtained by contacting the Office of the Secretary by telephone at 202-205-2000 or by accessing the USITC Internet server at *http://www.usitc.gov.*

vastly expanded the opportunities for private sector participation and trade in energy service markets worldwide.

The rapid pace of regulatory change, the complexities of the industry, and the relative novelty of addressing the sector within the framework of the GATS pose many challenges to trade negotiators. This report endeavors to address some of these challenges by examining the nature of regulatory reforms undertaken in a range of foreign energy markets and analyzing how these reforms influence competitive opportunities.

Approach and Data Sources

The information and analysis contained in this report were developed by Commission staff using primary and secondary data sources. USITC staff reviewed published sources and conducted interviews with technical experts from industry, government bodies, academic organizations, multilateral organizations, and consultancies in the United States and in a number of the countries covered in this investigation.

One of the most challenging aspects of this study was developing comparable information on each of the subject countries because of variations in terminology and in the extent of published information concerning reform programs. For some countries, extremely well organized and detailed descriptions of reform programs are presented on official Internet sites, whereas for others, relatively little information is available through any published sources. In part, this is due to the fact that some countries implemented reform several years ago, permitting time for a body of research and analysis to be developed, while others have only just begun the regulatory reform process. Commission staff have made every effort to provide reliable information and to reconcile differences in terminology, but variations in country coverage nevertheless persist.

Organization of the Report

After presenting an overview of the general concepts and approaches to regulatory reform in the natural gas industry (chapter 2), this report provides a series of country case studies (chapters 3-11) that provide a detailed examination of market reform in each of the subject markets. The report then concludes with a cross-country analysis which 1) summarizes the nature of market reforms and identifies similarities and differences; 2) discusses the nature of new competitive opportunities presented by the reforms; 3) describes remaining impediments to market development and the participation by foreign firms; and 4) examines the international trade implications of natural gas market reforms.

CHAPTER 2
OVERVIEW

This chapter presents how and why regulatory reform is taking place. Since market reform is a broad concept that means different things in different places, the chapter focuses mainly on the common features of different markets.

The chapter is divided into four sections. The first section of the chapter defines the different segments of the natural gas industry and assesses the viability of competition in each segment. The second section discusses the nature of government regulation in the sector. The third section provides the main characteristics of a comprehensive reform program. The fourth section focuses on the development of two distinct markets: the natural gas market, where participants trade natural gas as a commodity, and the gas transportation market, where participants trade transportation services for shipping gas through the pipeline system. Market reforms have generally separated these formerly bundled activities.

Segments of the Natural Gas Industry and Viability of Competition

Main Segments of the Gas Chain

From extraction to consumption, natural gas passes through many types of operations. Although there are usually no clear lines of demarcation between the sets of activities, three major functional segments can be distinguished:[1]

- Natural gas *production* refers to the set of operations required to deliver natural gas to the wellhead (e.g., exploration, drilling, and gathering).

- *Transmission*, or transportation, denotes the operations needed to deliver natural gas from the wellhead to distribution companies and to large end users (usually

[1] Paul W. MacAvoy, *The Natural Gas Market: Sixty Years of Regulation and Deregulation* (New Haven: Yale University Press, 2001). Andrej Juris "Competition in the Natural Gas Industry: The Emergence of Spot, Financial, and Pipeline Capacity Markets," *World Bank Public Policy for the Private Sector,* Note No. 137, Mar. 1998.

large industrial consumers or power plants) generally through high-pressure pipelines (including storage facilities).[2]

- *Distribution* consists of the operations needed for the delivery of natural gas to smaller end-users generally using low-pressure pipelines (including storage facilities).

These segments of the "gas chain" are presented in figure 2-1, along with their corresponding price and cost components. The purchase of the natural gas at the wellhead establishes the "wellhead price." The natural gas shipped to the city gate by high-pressure pipelines is resold at the "wholesale price." That gas is finally delivered to end users by the local distributing company through low pressure pipelines at the "retail price."

The "unbundling" of the natural gas commodity sale from the transportation services sale leads to the emergence of the natural gas *marketing* segment, which includes trading, brokering, retail supply, and many other services. Marketing activities are ubiquitous, as marketers may serve as intermediaries between any and all of the traditional market participants. This study principally focuses on the downstream natural gas market, which includes transmission, distribution, and marketing.

Viability of Competition

Reform programs in the natural gas industry are usually designed to introduce competition in segments where it is viable, and to improve regulations where competition is not feasible. Three main factors are believed to determine the viability of competition and the degree of competition in a given functional segment.[3] First, technology determines economies of scale and scope and thus optimal size of a firm.[4] Second, the size of a market determines how many firms may efficiently compete. Small countries have limited competition in their natural gas markets because their markets are not large enough to support efficient operation by a large number of domestic producers or suppliers.[5] Third, entry barriers may determine whether additional firms can enter the market. Because these factors vary substantially across countries and over time, no single characterization can be made regarding the viability of competition in any particular segment of the gas chain. Table 2-1 summarizes the primary functions

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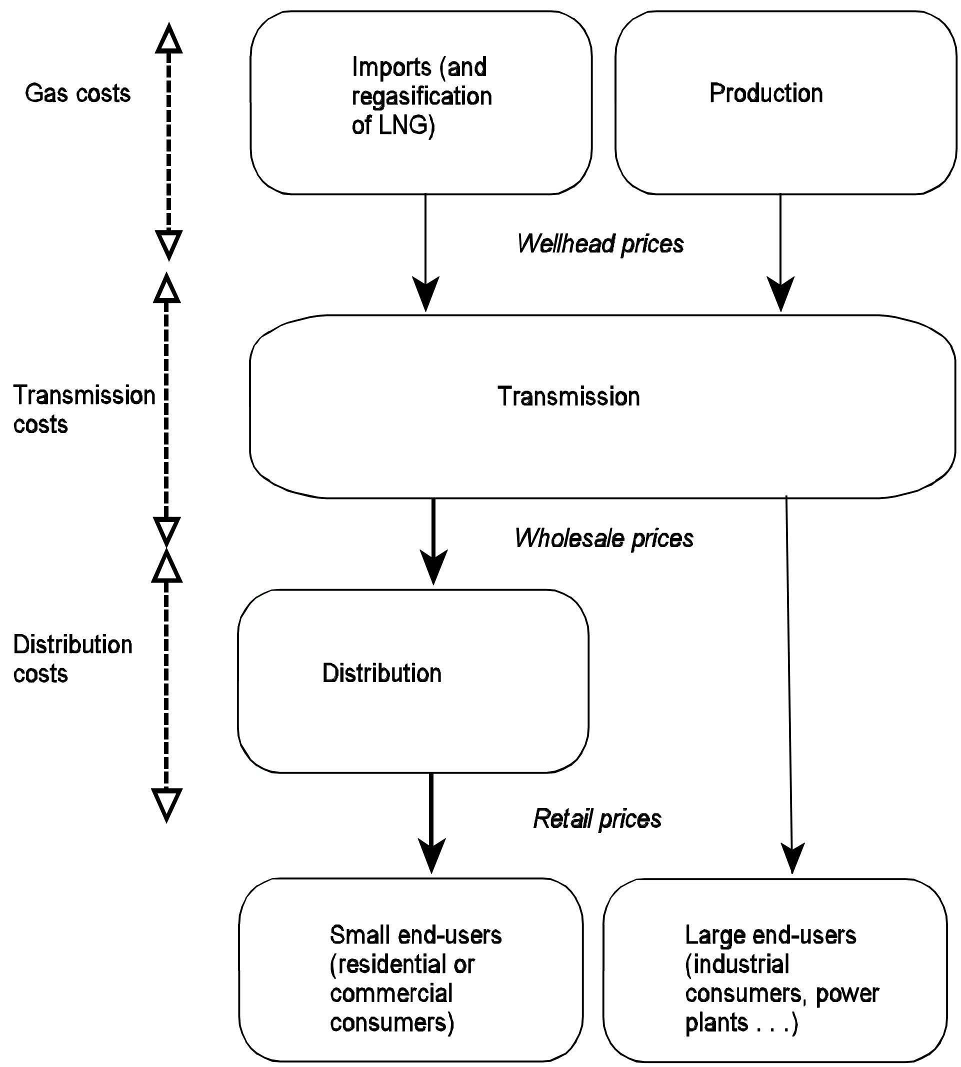
[2] Natural gas need not be produced locally. Natural gas can be imported through international pipelines or liquefied natural gas (LNG) can be imported through maritime transportation.

[3] Andrej Juris, "The Emergence of Markets in the Natural Gas Industry," *Policy Research Working Paper No. 1895*, The World Bank, 1998.

[4] Generally speaking, economies of scale occur when there is a decrease in the per-unit cost of producing a commodity as the output of that commodity rises. Economies of scope occur when it is cheaper to jointly produce a range of related products than to produce each of the individual products on their own. The presence of these economies tends to make the optimal size of a firm quite large.

[5] Note that large countries may have several separate geographical markets.

Figure 2-1
Natural gas industry: Market segments, cost components, and prices



Source: Compiled by the Commission.

Table 2-1
Natural gas market segments in a competitive regulatory framework

Segments	Primary functions	Likelihood and extent of competition	Customers
Production	Production (exploration, drilling, and gathering), development, and processing of natural gas Storage	Potentially competitive Often a few large firms, but potentially hundreds of firms in large markets	Marketers End users Transmission companies (to meet balancing needs)
Transmission	Transports gas from production or import location to distribution companies and large end- users through long-distance, high pressure pipeline networks Storage	Usually considered natural monopoly (prices regulated) but potentially competitive One (or a few) large firms	Marketers Producers End users (usually large industrial consumers and power plants that directly access the transmission pipeline) Distribution companies (where distribution companies continue to market gas to end users in addition to transport services)
Distribution	Transports gas from transmission pipeline to end users through local, low-pressure pipeline networks Storage	Usually considered natural monopoly (prices regulated) but potentially competitive One (or a few) large firms	Marketers Producers End users
Marketing	Buy, sell, and trade gas Provide pooling, storage, balancing, financing, and risk management services	Typically very competitive (prices determined by market forces) Many firms. Potential for consolidation may lead to oligopoly	Producers Transmission companies Distribution companies Other marketers End users

Source: Compiled by the Commission.

of the four different market segments, the likelihood of competition in each of them, and the list of potential customers who may be served by each segment. It is important to note that a firm may serve customers in both upstream and downstream segments, as producers may engage a marketer to sell their gas, while consumers may engage a marketer to purchase their gas. In such a case, producers and consumers are both customers of the marketing firm.

Firms in the production segment face large fixed costs and thus benefit from economies of scale, as well as economies of scope across a whole set of operations (e.g., exploration, drilling, and gathering). Such conditions tend to favor large firms. Yet, optimal firm size may be small relative to the size of the natural gas market. Consequently, the market may accommodate multiple competing producers. Significant competition appears to be viable, especially in very large regional markets. As an example, Canada has more than 700 competing producers.

Similar to the production segment, transmission and distribution require large infrastructure investment and are characterized by significant scale economies, which can serve as important barriers to entry.[6] These segments are widely considered to display "natural monopoly"[7] characteristics and, unless the market is extremely large, only one pipeline company is typically believed to be able to operate efficiently in these segments.[8] However, as pipelines become interwoven and gas trading techniques become more sophisticated, the transmission segment could potentially be organized competitively in a network of interconnected pipelines that offer many distinct paths between producers and end-users.[9]

Economies of scale are very limited in the marketing segment, so that the segment is potentially very competitive. Prices of natural gas can be freely determined by market forces and multiple firms can operate in the segment unless the market is extremely small. However, in contrast to the transmission sector, some degree of consolidation may take place as different regional markets become interconnected (or as the pipeline network becomes denser), leading to an oligopolistic market

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[6] Pipeline construction costs increase less than linearly while throughput increases exponentially: The cost of a pipeline is roughly proportional to its diameter, while its capacity increases with the square of its diameter. Hence, the larger the pipeline that is built, the lower the tariff (rates) required to produce a certain net return on the investment. Mary Lashley Barcella, "Natural Gas in the Twenty-First Century," *Business Economics*, Oct. 1996.

[7] A "natural monopoly" exists when production or supply costs are lowest when there is only one supplier.

[8] The lack of effective intermodal competition can strengthen the market power of gas pipelines. While natural gas could be transported either as LNG or through pipelines at the international level, natural gas pipelines provide the only practical (i.e., cost effective) link between producers and customers at the domestic level. In contrast, oil pipelines have to compete with tankers, barges, trucks and rail.

[9] Arthur de Vany and W. David Walls, "Open Access and the Emergence of a Competitive Natural Gas Market," *Contemporary Economic Policy*, Apr. 1994.

structure. Some marketers may be able to take advantage of the geographical differences in demand to arbitrage price imbalances across various supply regions.[10]

Regulation

Grounds for Regulation

It is generally believed that, under most conditions, competitive markets would lead to greater economic efficiency than regulated markets. That is, competition gives market participants incentives to minimize costs of production, which may lead to a reduction in consumer prices. In some circumstances, however, competitive market forces may fail to produce the most efficient resource allocation. Market failure occurs when competitive solutions do not exist (e.g., natural monopoly) or when externalities make a competitive solution undesirable.[11] In both cases, the private sector will not, on its own, be able to maximize social welfare, and government intervention may be required either to remedy the market failure or, accepting the failure, to provide incentives to produce an efficient result.[12]

For instance, substantial risks (in terms of recovering construction costs and generating rates of return sufficient to justify investment) are often associated with starting a new venture in the production or transmission segments. Given the large initial investment, financing depends crucially on assurances regarding future returns. Without government intervention to provide firms with sufficient assurance that they will be able to recoup their investment (such as guaranteed rights to extract monopoly rents), private incentives to invest and to develop the natural gas infrastructure may be missing. Regulation may also be necessary to minimize the short term risk of disruption of supply, the long-term risk of inadequate investment, and the risk of inadequate diversity of supply source–risks that the private sector may not be able to minimize on its own.

Additionally, regulations (such as those regarding standards) may be imposed to achieve consumer welfare protection and political or social objectives. For instance, the government may seek to provide protection to residential customers, particularly

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[10] For instance, a marketer serving different climatic regions (with varying seasonal natural gas demand) can contract with a producer for a steady volume of gas throughout the year, and consequently may be able to negotiate better contract terms than a marketer serving a single region. Mary Lashley Barcella, "Natural Gas in the Twenty-First Century," *Business Economics*, Oct. 1996.

[11] Externalities occur when a transaction affects parties not participating in the exchange. For example, the construction of a pipeline may pollute or decrease the value of the neighborhoods through which it passes. These effects are not taken into account in the profit maximization decision of the private pipeline builder. Hence, while private profits may be maximized, social welfare may be adversely affected.

[12] International Energy Agency (IEA), *Natural Gas Transportation: Organization and Regulation* (Paris: OECD/IEA, 1994), p. 69.

the disadvantaged.[13] Prices charged by a natural monopoly are, almost always, regulated to prevent it from exploiting the potential for excessive profits and/or to encourage it to minimize costs and to operate efficiently. Even in the most competitive market, some form of government regulation will typically exist to discourage noncompetitive behavior by certain market participants.[14]

Nature of Regulation

Regulatory responsibility is often assigned to a specialist agency or authority, which typically operates independently from short-term political interference. Their objectives and statutes are usually set forth in legislation. In some countries, regulation relies mainly on general competition and antitrust policies. In other countries, it is detailed and includes explicit mechanisms to control the behavior of a natural monopoly or a dominant service provider. Mechanisms could pertain to pricing and network access as well as financial and operational performance.[15]

Regulators typically achieve their regulatory objectives (e.g., efficiency or equity) using a mix of noneconomic (e.g., health, safety, and pollution controls or standards) and economic instruments (e.g., price or access controls). Many countries maintain some form of explicit price controls. In fact, even when competition has been established in the production and the marketing segments, price controls may still be applied to the transportation segment. The two most common types of price control are "rate of return" and "price cap" regulations.[16]

- The "*rate of return*" approach places a ceiling on the rate of return on capital for the regulated monopolies. Under this approach, also known as "cost-plus," the price paid by end users is based on estimated annual operating costs plus a reasonable return on investment. The targeted rate of return is typically set equal to the rate of return on capital facing the same risk as the utility's capital. The utility is, then, assured of earning the targeted rate of return since increases in costs can be passed on to consumers through higher prices. This is the approach adopted in Canada.

- Under the "*price cap*" approach, a ceiling is put on the prices charged by the company for a given period. In setting the price cap, the regulator determines an efficient level of performance, and devises incentives to assure its achievement. In what is known as the RPI-X regulation, the maximum price that the utility can charge is calculated periodically and is increased at an annual rate which is X percentage points below the increase in the general retail price index (RPI).[17] The "X" variable is computed to reflect "reasonable" efficiency gains to provide the company with incentives to reduce its costs to protect its earnings. If the regulated

[13] In some instances, a politically motivated government may use price regulation to induce cross-subsidization between favored and less favored groups of consumers.

[14] IEA, *Natural Gas Pricing in Competitive Markets* (Paris: OECD/IEA, 1998), p. 23.

[15] Ibid., pp. 23-24.

[16] Andrej Juris, "The Emergence of Markets in the Natural Gas Industry," *Policy Research Working Paper No. 1895*, The World Bank, 1998.

[17] This is also called CPI-X regulation, for Consumer Price Index.

company reduces its costs by more than the amount provided in the RPI-X calculation, it is rewarded with higher profits. This approach has been implemented in the United Kingdom and Argentina.

In some European countries, a monopolistic utility firm is allowed to set prices for end users on the basis of the different demand profiles of end users, which reflects the practical alternatives to and the cost of using other fuels.[18] This approach, known as the "*netback market value*," sets prices equal to the delivered price of the cheapest alternative fuel to the customer, minus gas transportation and storage costs, minus any gas taxes. This approach to pricing can result in significant profit margins, as the netback price may exceed the cost of supplying gas to specific customer categories by a wide margin. In some instances, however, the utility may elect to set prices below the average netback price to encourage new energy users or even existing oil users to choose or switch to natural gas.[19]

Reform Programs

Limitations of the Regulated Monopoly Model

Prior to regulatory reform, the natural gas industry, in most of the countries reviewed in this report, functioned under the traditional vertically-integrated monopoly model with production, transportation, distribution, and marketing performed by a single integrated gas utility which was generally granted extensive monopoly rights within a given area. The utility's prices were set based on a mix of "rate of return," "price cap," and "netback market value" approaches. As discussed above, the latter approach can involve price discrimination among different types of customers and allows the utility to extract economic rents from users who have no practical or cost-effective alternative to natural gas.

One weakness of the monopolistic model is the lack of transparency with respect to cost allocation and pricing. Moreover, regulations (and regulators) are, in some cases, unable to remedy the existing market failure by providing the monopolist firm with sufficient incentive to minimize cost, maximize efficiency and productivity, and reduce consumer prices. On the contrary, some contend that government control and intervention in gas companies' operations have in some cases exacerbated market failures by further distorting prices and leading to inefficient operation and deteriorating infrastructure.[20]

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[18] IEA, *Natural Gas Pricing in Competitive Markets*, pp 32-34.

[19] Note though that many energy customers are "captive," since changing to an alternative energy source could require considerable investment in equipment. Hence, overall demand may be price inelastic at least in the short term.

[20] Andrej Juris, "The Emergence of Markets in the Natural Gas Industry," *Policy Research Working Paper No. 1895*, The World Bank,1998.

Policy Trends and Shifts

The problems associated with the regulated monopoly model have led to a shift in policy towards greater reliance on market forces. Reforms in the natural gas industry are, in essence, aimed at limiting the state's role in the industry's day-to-day operations so that only those segments of the industry where competition is not feasible (or where it is feasible but does not produce efficient outcomes) would be regulated while market forces would balance demand and supply in the remaining segments. Regulations that were designed to be *substitutes for competition* are to be replaced by ones aimed at *introducing competition* wherever the latter is feasible.

The United States, Canada, and the United Kingdom initiated such reforms as early as the late 1970s and early 1980s. Their examples, among other factors, have encouraged other countries to introduce reforms to boost economic efficiency and to attract new private investment in their natural gas sector. In many countries, including all of the subject countries of this report, the natural gas industry is evolving from a monopolistic into a competitive industry with increasing numbers and types of participants.

Common Features of Reform Programs

In general, reform programs comprise two broad categories of policy changes:

- *Structural measures* alter the ownership structure of different segments of the industry, entailing the privatization of state-owned companies and/or the separation– "unbundling– of the main activities of existing monopolies (along vertical and horizontal lines) so that they might be provided by different entities. Breaking up a vertically integrated company helps ensure that costs are correctly allocated to the corresponding activities, ensuring greater transparency and promoting competition in segments where competition has been introduced.[21] While the unbundling requirements can vary from complete separation of ownership to simple separation of operating units within the same firm, integrated utilities are typically required to keep separate financial accounts for different activities.

- *Regulatory measures* foster market access by new entrants and encourage competition in the determination of prices in different activities. In the production and marketing segments, regulatory control over prices may be lifted entirely. In the transportation segment, regulatory constraints may be imposed to limit monopoly rents and ensure nondiscriminatory access to essential facilities.[22] Regulatory measures could also involve the introduction of new standards to shape the behavior of firms in such areas as health, safety, and pollution control.

[21] These benefits from unbundling are often achieved with the loss of different efficiency gains obtained from vertical integration (e.g., transaction costs and economies of scope).

[22] IEA, *Natural Gas Transportation: Organization and Regulation*, p. 70.

Typical reform programs involve both structural and regulatory change. They could start with the vertical unbundling of the different segments (production, transmission, and distribution); and proceed to horizontal unbundling within the production and marketing segments. Competition is then made possible by unbundling gas commodity sales from transportation services, lifting regulatory control over gas commodity prices, and introducing mandatory, nondiscriminatory, open access to the pipeline networks. In such a market, consumers can purchase natural gas directly from producers or from marketing companies, bypassing their existing gas distribution company, which now earns revenue only for providing the transportation service. This market model stimulates the appearance of large numbers of marketers who buy gas from one or several producers and resell it later to other market participants and consumers.[23] Marketers are also responsible for arranging transportation of the gas by booking capacity and paying use-of-system charges, which are typically regulated to ensure a fair rate of return to the system operator.[24]

Emergence of Natural Gas and Transportation Markets

The International Energy Agency reports that "the introduction of competition in natural gas markets in North America and the United Kingdom has led to changes in the structure of gas prices and reduction, on average, in real pre-tax prices in parallel with rising volumes delivered."[25] In general, structural and regulatory measures result in a wider range of services available to wholesale and retail buyers, as well as a substantial increase in the number and complexity of transactions. As noted, they effectively create two distinct markets: the natural gas market, where participants trade natural gas as a commodity, and the transportation market, where participants trade transportation services for shipping gas through the pipeline system.[26] The emergence of these two markets is discussed separately in the next two sub-sections.

Natural Gas Market

In the natural gas market, gas is traded as a commodity in the form of gas contracts. The main participants include producers, marketers, distribution companies, and end users. Purchases of gas for further resale are conducted in the wholesale market, while purchases for end use take place in the retail market. The duration of the contract could be short, medium, or long term. Since they keep supply and price risks low, long-term supply contracts used to be the most common way of acquiring gas. However, pronounced fluctuations in natural gas prices have motivated market

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[23] IEA, *Regulatory Reform: European Gas* (Paris: OECD/IEA, 2001), p. 11.

[24] IEA, *Natural Gas Pricing in Competitive Markets* (Paris: OECD/IEA, 1998), pp. 21-22.

[25] Ibid., pp. 17-18, p. 17. See also IEA, *Regulatory Reform: European Gas*.

[26] Andrej Juris, "Competition in the Natural Gas Industry: The Emergence of Spot, Financial, and Pipeline Capacity Markets," *World Bank Public Policy for the Private Sector*, Note No. 137, Mar. 1998.

participants to reduce the average length of supply contracts in favor of short term contracts.[27] This, in turn, led to the development of a spot market, where market participants can react to changing market conditions and trade natural gas on a daily basis.[28] Active, unregulated spot markets offer the benefits of intense competition, high liquidity, and greater efficiency in the pricing of natural gas.[29] Where there are open access pipeline transportation arrangements, spot prices are expected to converge across different regions as a result of the increasing ability to move gas from one region to another.[30]

A financial gas market usually emerges when the physical gas market has reached a certain level of maturity and a large share of natural gas is traded under short term contracts. The volatility of spot prices creates the need for tools to minimize price risks, which in turn leads to the development of a financial instruments used to hedge prices. Transactions in the financial gas market typically involve the transfer of risk between spot market participants with different risk management skills and risk adversity characteristics. Financial instruments are commonly used for risk management, speculation, and price arbitrage and can take various forms. Futures and options are standardized contracts typically traded in established commodity exchanges. Forward contracts and swaps are typically custom tailored, with every aspect negotiated by the parties to the contract.[31]

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[27] For instance, demand for gas heating and to some extent electric power generation is highly seasonal and strongly correlated with weather. IEA, *Natural Gas Pricing in Competitive Markets*, p. 16.

[28] Spot markets are (more or less informal) markets for short-term, over-the-counter trades of fixed volumes of gas at a negotiated market price. In these markets, prices are highly transparent.

[29] Short-term spot prices should, in principle, reflect the economic value of natural gas (i.e., the economic cost of getting it and the consumer's willingness to pay for it). Andrej Juris, "Competition in the Natural Gas Industry: The Emergence of Spot, Financial, and Pipeline Capacity Markets," *World Bank Public Policy for the Private Sector,* Note No. 137, Mar. 1998.

[30] Mary Lashley Barcella, "Natural Gas in the Twenty-First Century," *Business Economics*, October 1996. An econometric study of the U.S. market found that, as open access emerged and opened alternative network paths for moving natural gas, prices across connected regions initially converged and eventually became highly correlated. Arthur de Vany and W. David Walls, "The Triumph of Market in Natural Gas," *Public Utilities Fortnightly*, Apr. 15, 1995.

[31] Paul W. MacAvoy, *The Natural Gas Market: Sixty Years of Regulation and Deregulation* (New Haven: Yale University Press, 2001). Andrej Juris, "Competition in the Natural Gas Industry: The Emergence of Spot, Financial, and Pipeline Capacity Markets," *World Bank Public Policy for the Private Sector,* Note No. 137, Mar. 1998.

Transportation Market

Transportation services are sold in the form of transportation contracts.[32] Because transportation facilities exhibit natural monopoly characteristics and duplication of facilities are believed to be inefficient, access to transportation infrastructure is often seen as a prerequisite for competition in the gas market.[33] As an integral part of most reform programs, pipeline companies are required to provide open and nondiscriminatory third-party transportation services to shippers who have made their own separate gas supply arrangements. A mandatory open access regime may be negotiated or regulated.

- In a negotiated access regime (as in Australia), the regulator lets the industry regulate itself;

- In a regulated access regime (as in the United Kingdom and Canada), the regulator explicitly controls how pipeline companies handle requests for access.

The market for pipeline capacity is subdivided into a primary market and a secondary market. The former consists of long term firm transportation (LTFT) contracts. An LTFT leasing arrangement allows the shipper to use a given amount of pipeline capacity at any time, provided that the pipeline is prenotified of the intended usage. The contract specifies the maximum daily quantity of gas that can be transported through the pipeline and the points of injection and withdrawal. The price for the transportation service is regulated.

If any of the reserved capacity is not needed, the shipper may resell the capacity under a "capacity release" program in a competitive secondary market. Buyers of pipeline space that resell their excess space on the secondary market are in direct competition with the pipeline company offering primary contract spaces. That is, as more short term capacity becomes available at a lower price on the secondary market, demand for the pipelines' higher priced, long-term capacity declines. Reserved capacity that is not released to a secondary shipper and cannot be used by the primary shipper may be marketed a second time by the pipeline company as interruptible capacity, which is subject to immediate recall, or short term firm transportation of less than a year's duration.[34] The resale of firm transportation

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[32] Andrej Juris, "Competition in the Natural Gas Industry: The Emergence of Spot, Financial, and Pipeline Capacity Markets," *World Bank Public Policy for the Private Sector*, Note No. 137, Mar. 1998.

[33] An alternative approach is to remove monopolies and granting freedom to build pipelines. So far, Germany has been the only country that opted for this.

[34] Arthur de Vany and W. David Walls, "Open Access and the Emergence of a Competitive Natural Gas Market," *Contemporary Economic Policy*, vol. XII, Apr. 1994. Mary Lashley Barcella, "Natural Gas in the Twenty-First Century," *Business Economics*, Oct. 1996.

contracts can lead to efficient allocation of capacity, since it allows contract holders to realize market value for unused capacity.[35]

Conclusion

The general concepts of regulatory reform described in this chapter have been applied to varying degrees by each of the countries examined in this report. The following chapters present the nature of each country's reform program in some detail, how the reforms have led to changes in industry structure, and the extent to which competitive markets for gas and transportation capacity have developed.

[35] Andrej Juris, "Competition in the Natural Gas Industry: The Emergence of Spot, Financial, and Pipeline Capacity Markets," *World Bank Public Policy for the Private Sector*, Note No. 137, Mar. 1998.

CHAPTER 3
ARGENTINA

Overview

Natural gas is Argentina's primary energy source, accounting for approximately 46 percent of total energy consumption in 1999.[1] Reform of the natural gas industry began in 1989, when Argentina introduced a series of decree laws directing privatization and the introduction of competition into the upstream production segment.[2] Implementation of this initiative resulted in the 1991 privatization of the state-run oil and gas company, Yacimientos Petroliferos Fiscales (YPF), and in the elimination of its production monopoly rights. Downstream reforms followed with the passage of the Natural Gas Act of 1992, which brought about privatization and structural reform of the downstream natural gas transportation, distribution, and marketing segments. The 1992 Act split the state-run monopoly, Gas del Estado (GdE), into two transmission companies - Transportadora de Gas del Sur (TGS) and Transportadora de Gas del Norte (TGN) - and eight distribution companies, all of which were subsequently privatized.[3] The Act guaranteed third-party access for all transmission and distribution pipelines; imposed vertical separation by barring transmission companies from buying and selling gas and by prohibiting gas marketers from owning a majority share in transmission companies; and limited cross-shareholding between transmission and distribution companies. Competition was introduced in natural gas marketing by permitting large industrial consumers and local distribution companies to contract directly with other marketers or producers for their supplies. The residential and commercial segments remained regulated, however, as the local distribution companies retained exclusive rights to market natural gas to consumers of less than 10,000 cubic meters per day.

The 1992 Act also mandated the creation of the independent regulator, Ente Nacional Regulador del Gas (Enargas), which is structured as a commission with five directors. The responsibilities of Enargas include protecting consumer interest, promoting competition, encouraging investment, setting tariffs for transmission and distribution services, and ensuring third-party access to pipeline network facilities.[4]

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[1] U.S. Department of Energy (USDOE), Energy Information Administration (EIA), *An Energy Overview of Argentina*, May 2001, found at Internet address *http://www.eia.doe.gov*, retrieved Aug. 10, 2001.

[2] Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA), *Regulatory Reform in Argentina's Natural Gas Sector*, (Paris: OECD/IEA, 1999), p. 31.

[3] Ibid., pp. 29-30.

[4] Ibid., p. 31.

Industry Structure

Production and Imports

Argentina's natural gas reserves are located in 19 sedimentary basins, with production currently taking place in five basins: Noroeste in the north; Neuquen and Cuyo in central Argentina; and Golfo San Jorge and Austral in the south. The Neuquen basin accounts for nearly 60 percent of gas production, and 50 percent of proven reserves.[5] Argentina also imports approximately 4.8 million cubic meters of natural gas daily from Bolivia, which represents about 5 percent of supply.[6]

Natural gas exploration and development increased markedly after industry restructuring, resulting in production growth of over 60 percent during 1990-97.[7] More than 35 private companies presently operate in the natural gas production and exploration market, with YPF continuing to hold the largest share of the market. In 1999, YPF was acquired by Repsol (Spain) for $13.4 billion in 1999 and renamed Repsol YPF.[8] As a condition for approving the transaction, the Argentine Government required Repsol YPF to reduce its market share from 60 percent to 44 percent by January 2001.[9] Repsol subsequently complied by swapping assets with Petrobras (Brazil) in December 2000.[10] The French firm, Total, produced 17 percent of output in 1999, making it Argentina's second largest producer.

Transmission and Distribution

Argentina's transmission network consists of five high-pressure pipelines (figure 3-1). Three pipelines bring gas from the Neuquen and Cuyana basins, and two pipelines connect the Austral basin with the Noroeste basin. All five pipelines link to the Greater Buenos Aires market.[11] Four pipelines connect Argentine supply sources with Chile, Argentina's largest export market. The GasAndes pipeline runs to central Chile from Argentina's Neuquen basin. The Gasoducto del Pacifico pipeline, which began operating in 1999, transports 140 million cubic feet per day to Chile's southern region. Two parallel competing pipelines supply northern Chile. A pipeline connecting northwest Argentina with Brazil became active in July 2000. This pipeline supplies gas to a 500 megawatt (MW) power plant in Uruguaina,

[5] OECD, IEA, *Regulatory Reform in Argentina's Natural Gas Sector*, p. 25.

[6] IADB, *Liberalization of the Gas Sector in Latin America*, p. 25.

[7] OECD, IEA, *Regulatory Reform in Argentina's Natural Gas Sector*, p. 46.

[8] Repsol YPF, corporate information found at Internet address *http://eng.repsol-ypf.com*, retrieved Aug. 30, 2001, and Jenny Anderson, "Reconquista," *Institutional Investor*, Jan. 2000, found at Internet address *http://proquest.umi.com*, retrieved Aug. 30, 2001.

[9] Helen Avati, "Regulating the Flow," *Petroleum Economist*, Sept. 1999, found at Internet address *http://proquest.umi.com*, retrieved Aug. 30, 2001.

[10] Repsol YPF press release, "Repsol YPF and Petrobras Conclude Valuation," Dec. 28, 2000, found at Internet address *http://eng.repsol-ypf.com*, retrieved Aug. 30, 2001.

[11] OECD, IEA, *Regulatory Reform in Argentina's Natural Gas Sector*, p. 25.

Figure 3-1
Natural gas pipelines in South America

Source: Used with permission from the Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA). Map obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition*.

Brazil. Additional Argentina-Brazil pipelines are planned[12] and a pipeline connecting Buenos Aires to Montevideo, Uruguay, is scheduled to begin operations in 2002.[13]

As noted above, Argentina's gas transportation pipelines are controlled by two companies, TGN in the north and TGS in the south. TGN controls 4,900 kilometers (km) of pipelines, which are supplied by the Cuyo and Neuquen gas basins, as well as imports from Bolivia. TGS owns 6,000 km of pipeline, and transports gas from the Austral and Neuquen basins. TGN and TGS are to some extent competitors, as both may serve Buenos Aires, the largest regional market. In addition, neither company holds exclusive territorial rights, so any firm may invest to construct new transmission capacity. Majority shares in both companies were sold to private investors in 1992. Nova Corporation (Canada) operates TGN and holds a 20-percent equity stake. Enron (U.S.) controls TGS with 37 percent of its equity.[14]

The distribution market is organized regionally into nine areas. Each area is assigned to a distribution company, which has exclusive rights to develop the distribution network.[15] Distributors are legally obligated to serve all end-users, although their marketing monopoly is restricted to consumers using less than 10,000 cubic meters per day.[16] All of the distribution companies are majority-owned by private firms. Argentina's three largest distributors service the greater Buenos Aires region. Metrogas covers most of metropolitan Buenos Aires. Gas Pampeana covers southern Buenos Aires and many southern provincial towns. Gas Natural Ban covers the northern part of Buenos Aires. Several North American companies own stakes in distribution companies, including LG&E Energy (U.S.-based but owned by Powergen of the United Kingdom), Sempra Energy (U.S.), and Dominion Resources (U.S.).[17]

In some cases, distribution companies are required to maintain and invest in the distribution networks. Compulsory investments are required to ensure the security and integrity of the system. Noncompulsory investments are undertaken to help meet expected demand increases and to improve system efficiency.[18] Investment increased from $93 million in 1993 to an annual average of $200 million during 1994-97. Reportedly, increased investment has resulted in network expansion, improved system control, and greater reliability.[19]

During the privatization process, transmission and distribution providers received 35-year operating licenses from Enargas, with the possibility of a 10-year extension. At the end of this 35- or 45- year period, licenses will be issued through a competitive bidding process. Transmission and distribution tariffs are regulated by Enargas based on a price-cap methodology. Under this approach, Enargas determines a maximum

[12] USDOE, EIA, *Argentina Country Report.*

[13] U.S. Department of State Telegram, "Buenos Aires-Montevideo Gas Pipeline Moving Forward," message reference No. 221918Z, prepared by U.S. Embassy Montevideo, Jan. 2001.

[14] IADB, *Liberalization of the Gas Sector in Latin America*, p. 26.

[15] Ibid., p. 27.

[16] OECD, IEA, *Regulatory Reform in Argentina's Natural Gas Sector*, p. 30.

[17] Ibid., p. 44.

[18] IADB, *Liberalization of the Gas Sector in Latin America*, p. 27.

[19] OECD, IEA, *Regulatory Reform in Argentina's Natural Gas Sector*, p. 44.

allowable tariff which may be adjusted every six months to account for inflation, network investment, and efficiency incentives.[20]

Markets and Pricing

Argentina's regulatory reforms essentially introduced competitive pricing in the production and bulk marketing segments. Regulated pricing was retained for transmission and distribution services as well as for marketing to smaller commercial and residential consumers. Local distribution companies and large consumers may now choose to source their supplies from among various marketers, who may be producers or independent intermediaries. Large consumers may also opt to continue purchasing gas through their local distribution company at rates regulated by Enargas. However, lower prices offered by competitive firms have attracted many large consumers away from the local distribution company. By 1997, nearly 32 percent of total gas sales were negotiated at competitive prices.[21]

Negotiated transactions typically vary depending upon the type of consumer.[22] For example, electric power generators tend to prefer 15-year contracts, while industrial users often elect for shorter term contracts of 1 to 3 years. Most of these contracts contain take-or-pay clauses, with escalation clauses to account for price swings in competing fuels. In addition to negotiating long-term contracts, eligible market participants may also buy and sell gas through an informal spot market. Although spot market trading has been slow to develop, activity has increased recently among local distribution companies. Gas distributors BAN and Gasnor purchased approximately 20 percent of their respective gas requirements from the spot market in 1997, compared with 2 to 3 percent in 1996. In 2000, there were approximately 6 licensed gas brokers participating in the spot market.

In addition to negotiating for the sale of gas, marketers must also arrange for its physical delivery by reserving capacity on the transmission and distribution network. As part of the restructuring program, however, existing transmission capacity was allocated to the local distribution companies for a period of 10 years.[23] As a result, these companies continue to control an estimated 95 percent of transmission capacity, which means that, in practice, marketers book both transmission and distribution capacity through the local distribution company.[24] In 1997, Enargas attempted to create a secondary market in transmission capacity by requiring transmission companies to establish and maintain a centralized exchange where holders of firm capacity can release unwanted capacity for short periods. Prices are determined competitively, but are not permitted to go above the maximum tariffs for primary

[20] Inter-American Development Bank (IADB), "Liberalization of the Gas Sector in Latin America: The Experience of Three Countries," (IADB: Washington, DC June 2000), ref. No. IFM-124, p. 29.

[21] OECD, IEA, *Regulatory Reform in Argentina's Natural Gas Sector*, p. 53.

[22] Ibid., p. 54.

[23] Ibid., p. 29.

[24] Ibid., p. 55.

capacity. The cap is intended to prevent distribution companies from deliberately purchasing more transmission capacity than they actually need to sell on the secondary market in order to make a profit. However, the secondary market has failed to develop, in part because the price cap may not offer enough of a financial incentive for distribution companies to release unused capacity.[25]

The results of regulatory reform seem to be substantial. After the removal of price controls, the average wellhead price increased by 15 percent during 1993-95.[26] Since consumption also increased significantly (by nearly 50 percent during 1992-97), the regulated price for gas prior to reform appears to have been well below its competitive market value. Indeed, even after the price increase, prices for natural gas in Argentina remained lower than those in other major markets, including those in the United States and the United Kingdom. Since producers could now realize greater profits, the number of wells drilled increased from 14 in 1993 to peak at 72 in 1995 before receding to 40 new wells in 1997.[27] Transmission and distribution capacity likewise increased by 36 percent and 38 percent during 1992-97, respectively.

Impediments to Competitive Market Development

Although Argentina has made considerable progress toward building a competitive natural gas market, some impediments persist. Most notably, competition has been deterred in the upstream production segment due to the enduring dominance of Repsol YPF.   However, some progress appears to have been made in this regard. In September 1999, Argentina strengthened its anti-monopoly legislation by giving the government greater authority to support competition, block mergers, and impose penalties for the abuse of market power.[28] In September 2000, Repsol YPF announced that it would voluntarily phase out marketing natural gas produced by other firms over a 5-year period, thereby reducing some of its market share.[29] This was followed by the December 2000 announcement that Repsol YPF had agreed to sell some of its assets to Petrobras. As a result of these actions, the market share of Repsol YPF appears to have been reduced from 60 percent to 44 percent as of 2001. Nevertheless, Repsol YPF may still retain sufficient market power to affect pricing for the market as a whole.[30]

Another factor impeding the development of a competitive market is the minimum consumption threshold for consumers to be eligible to choose an alternative gas marketer. Limiting the pool of potential customers to only the largest consumers diminishes opportunities for new entrants and constrains the volume of transactions.

[25] Ibid., p. 40.
[26] Ibid., p. 56.
[27] Ibid., pp. 48-51.
[28] U.S. Dept. of State, “FY 2001 Country Commercial Guide: Argentina,” found at Internet address *http://www.stat-usa.gov*, retrieved Aug. 30, 2001.
[29] Repsol YPF press release, “Repsol YPF Natural Gas Commitment in Argentina,” Sept. 30, 2000, found at Internet address *http://eng.repsol-ypf.com*, retrieved Aug. 30, 2001.
[30] U.S. industry representative, interviews with USITC staff, Buenos Aires, Argentina, June 20-24, 2000; and IADB, *Liberalization of the Gas Sector in Latin America*, p. 30.

This reduces the size and liquidity of the natural gas market and may explain, in part, why the spot market has been slow to develop.[31] However, changing the threshold may be difficult because it would involve changing the concession terms negotiated during the privatization process, when private investors were guaranteed exclusive rights to all consumers below the threshold.[32]

With respect to international trade, Argentina's market reforms appear to be fully consistent with international principles concerning trade and investment. As a result, Argentina does not appear to maintain any measures that would constitute significant impediments to market access or investment by foreign firms.

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[31] In illiquid spot markets, potential participants can not be assured that they will find a counterparty when they need to execute a transaction. Consequently, they may choose to bypass the spot market and enter into long-term bilateral contracts.

[32] IADB, *Liberalization of the Gas Sector in Latin America*, p. 31.

CHAPTER 4 AUSTRALIA

Overview

Reform of Australia's natural gas industry began in the mid-1990s as part of a broad effort to create a unified national energy market. The objectives of reform were to introduce competition into the market and enhance opportunities for private sector involvement. These, in turn, were expected to lower prices for energy users, increase consumer choice, allow for more sustainable use of energy resources, and improve the competitiveness of Australian industries at home and abroad.[1]

The legal basis for reform of Australia's natural gas market was established in February 1994, when the Australian State and territory governments committed to achieving "free and fair trade in natural gas."[2] This commitment was incorporated into two new pieces of Federal legislation: the Competition Principles Agreement 1994 and the Competition Policy Reform Act 1995, which amended the Trade Practices Act 1974.[3] These laws form the legal basis for the National Access Regime, introduced in 1995. The National Access Regime set forth four primary objectives for the natural gas industry: (1) to develop an open, fair, and transparent regime for third-party access to Australia's natural gas pipelines; (2) to facilitate the development and operation of a nationwide gas market that includes safeguards against monopoly power abuse; (3) to allow customers to choose their natural gas suppliers; and (4) to encourage the development of a nationally integrated pipeline network.[4]

The Natural Gas Pipelines Access (Intergovernmental) Agreement, passed on November 7, 1997, was the first step toward implementing the National Access Regime. The agreement, which included the Gas Pipelines Access Law (GPAL) and the National Third Party Access Code (the Code), established a new regulatory framework modeled after the National Access Regime. The agreement applied to the transmission and distribution of natural gas in Australia, and outlined steps for the completion of a nationwide natural gas market.

[1] "Developing a National Energy Market," *Australian Energy News 2*, Dec. 1996, found at Internet address *http://www.isr.gov.au*, retrieved Mar. 29, 2001.

[2] *Gas Regulatory Arrangements*, May 1999, found at Internet address *http://www.isr.gov.au*, retrieved Feb. 1, 2001.

[3] The Trade Practices Act (of) 1974 was established by the National Government of Australia to promote fair competition and protect consumers against anticompetitive behavior on the part of domestic firms.

[4] Department of Industry, Science, and Resources, "Gas Regulatory Arrangements," May 1999, found at Internet address *http://www.isr.gov.au*, retrieved Jan. 31, 2001.

The agreement required each State and territory to develop a regulatory framework that followed a common set of principles.[5] South Australia was the first to develop such a framework, the Natural Gas Pipelines Access (South Australia) Agreement 1997, which became the model for other state and territory agreements. A final piece of legislation, the Gas Pipelines Access (Commonwealth) Act 1998, extended the National Third Party Access Code to external territories, off-shore pipelines, and interstate pipelines.[6]

Once each of the State and territory governments adopted a new set of principles governing their natural gas markets, they began to pursue practical regulatory measures to achieve market reform. Such measures were intended to introduce competition, lower retail prices, increase private sector involvement, and facilitate market integration. First, State and territory governments encouraged private-sector participation in the natural gas market by corporatizing, or privatizing, government-owned assets. Second, in order to discourage cross-subsidization and other anticompetitive behavior among gas market participants, governments introduced 'ring-fencing', or vertical unbundling. Ring-fencing requires vertically integrated firms to separate business units on an accounting, legal, and operational basis.[7] In practice, many of Australia's natural gas companies have also pursued ownership separation, establishing their transmission/distribution and retail supply units as separate corporate entities.[8] Third, governments introduced third-party access to transmission and distribution pipelines. Third-party access terms, including tariffs, are submitted by facility owners and approved by independent state or national regulators. Finally, State and territory governments introduced formal dispute resolution mechanisms should commercial negotiations fail.[9]

At the national level, regulatory authority was divided among several bodies to address a separate sector or portion of the market. The Australian Competition and Consumer Commission (ACCC) was granted regulatory authority over most of the transmission pipeline system. At the State level, government authorities were free to grant regulatory authority over the local distribution networks to an independent state regulatory body or to delegate responsibility to the ACCC. At present, each State or territory grants authority to independent State-level bodies, except for Western

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[5] Western Australia was exempted, however, and has been allowed more authority at the state level.

[6] Productivity Commission, "Review of the National Access Regime," Mar. 29, 2001, found at Internet address *http://www.pc.gov.au*, retrieved May 31, 2001.

[7] In July 1997, the Victoria State-owned Gas and Fuel Corporation was unbundled into three competing gas distribution businesses. To each was "stapled" a retail service provider to operate in separate geographical areas of the state. These stapled interests were subsequently sold off separately to private sector companies in May1999, See *Gas Facts*, Australian Gas Association, found at Internet address *http://www.asn.org.au,* retrieved Jan. 31, 2001.

[8] Ring-fencing requires "the monopoly [transmission or distribution] business to be separated from the retail business of the company, including separating accounts, staff, and customer information." See *Gas Regulatory Arrangements*, May 1999, found at Internet address *http://www.isr.gov.au,* retrieved Feb. 1, 2001.

[9] Productivity Commission, "Review of the National Access Regime," Mar. 29, 2001, found at Internet address *http://www.pc.gov.au*, retrieved May 31, 2001.

Australia, which retains the power to appoint a regulator for both the transmission and distribution sectors (table 4-1).[10]

The National Competition Council (NCC) establishes guiding principles for access to all Australian pipelines, and is responsible for approving access terms that are adopted by the States and territories (table 4-2). In addition, the NCC approves or revokes access arrangements proposed by the owner of each pipeline covered under the Code.[11] The NCC also addresses public concerns through an open consultation process, and provides guidance on the implementation of new regulations.[12]

Industry Structure

Production and Imports

The Australian domestic natural gas market is supplied entirely by domestic production. Natural gas producers are privately owned, but because there are relatively so few of them and a number of long-term contracts remain, this segment is not highly competitive. Australia produces over 1,115 billion cubic feet (bcf) of natural gas per year, of which 392 bcf are exported as LNG. Natural gas accounts for 18.1 percent of primary energy use in Australia. It is the third largest source of energy after oil and coal, and is expected to be the fastest growing energy source in Australia. Estimates project that the primary energy share of natural gas will increase to 22 percent by 2005. In total, Australia's proven and probable reserves amount to 101,308 bcf, which is equal to 91 years of continued supply at current production levels. These reserves are three times the proven reserves of oil in Australia.[13]

Natural gas resources are located in onshore and offshore basins. The Carnarvon and Browse Basins off the coast of Western Australia account for 45 percent and 34 percent, respectively, of proven remaining reserves of natural gas in Australia. In contrast, the Cooper-Eromanga basin in South Australia accounts for 5 percent of remaining reserves, and the Gippsland Basin off the south-east coast of Victoria contains 7 percent of remaining reserves. Only New South Wales lacks any viable reserves of natural gas. The lack of transcontinental pipelines linking Western Australia and the eastern consumer market means th.at the basins with the majority of Australia's reserves supply only customers in Western Australia and the LNG export markets. Transcontinental pipelines planned by Phillips Petroleum (US) and Epic

[10] Office of Gas Regulator (OffGAR), *Annual Report 2000*, found at Internet address *http://www.offgar.wa.gov.au*, retrieved Feb. 1, 2001.

[11] Coverage under the Code is based on the determinations and recommendations of several parties. A pipeline may be left uncovered if doing so does not adversely impact the competitive market elsewhere, nor leave customers of the pipeline in question worse off.

[12] National Competition Council, found at Internet address *http://www.ncc.gov.au, retrieved Feb. 2, 2001.*

[13] Australian Gas Association, Australia's Gas Industry Overview, found at Internet address *http://www.asn.org.au*, retrieved Jan. 31, 2001.

Table 4-1
National and State regulatory bodies in Australia

Regulatory Body	Jurisdiction[1]	Responsibilities
Australian Consumer & Competition Commission (ACCC)	National	Regulates access to transmission pipeline system. Reviews Reference Tariffs and arbitrates disputes.
National Competition Council (NCC)	National	Develops guidelines concerning the form and content of applications for coverage under the Code. Makes recommendations to Ministers on certification issues.
National Gas Pipelines Advisory Committee (NGPAC)	National	Administers the Code. Monitors and reports on operation of GPAL and Code.
Independent Competition & Regulatory Commission (ICRC)	ACT (Canberra)	Approves access arrangements, regulates third-party access to gas distribution networks, and arbitrates disputes
Independent Pricing & Regulatory Tribunal (IPART)	New South Wales	Approves access arrangements, regulates third-party access to gas distribution networks, and arbitrates disputes.
Office of Gas Access Regulation (OffGAR)	Western Australia	Approves access arrangements, regulates third-party access to gas distribution networks, and arbitrates disputes.
Office of Regulator General (ORG)	Victoria	Approves access arrangements, regulates third-party access to gas distribution networks, and arbitrates disputes
Queensland Competition Authority (QCA)	Queensland	Approves access arrangements, regulates third-party access to gas distribution networks, and arbitrates disputes
Independent Pricing & Access Regulator (SAIPAR)	South Australia	Approves access arrangements, regulates third-party access to gas distribution networks, and arbitrates disputes

[1] Regulatory bodies do not exist in the Northern Territory and Tasmania.

Source: Compiled by the Commission.

Table 4-2
Status of State and territory access regimes in Australia

Jurisdiction	Regime enacted	Regime certified effective
New South Wales	Yes	Certified for 15 years on Mar. 29, 2001
Victoria	Yes	Certified for 15 years on Mar. 29, 2001
Queensland	Yes	Recommended to Minister for certification by NCC
Western Australia	Yes	Certified for 15 years on May 31, 2000
South Australia	Yes	Certified for 15 years on Dec. 9, 1998
Tasmania	Yes	No application yet made to NCC
Canberra (ACT)	Yes	Certified for 15 years on Sep. 25, 2000
Northern Territory	Yes	Application made to NCC on Mar. 13, 2001
Commonwealth (National)	Yes	Not applicable

Source: National Competition Council, as of Mar. 31, 2001, found at Internet address *http://www.ncc.gov.au*, retrieved on Apr. 6, 2001.

Energy (Australia) promise to end this situation, connecting eastern markets with western reserves via pipelines through the Northern Territory.[14]

Domestic production and consumption of natural gas has increased steadily since 1980. Prior to 1989, when LNG exports began, production and consumption increased in unison from about 279 bcf annually to about 557 bcf annually. After 1989, domestic production began to outpace domestic consumption consistently at a rate of roughly two to one.[15] Despite these domestic production increases and prospects for continued growth in production and LNG exports, there remain areas of Australia unserved by natural gas. A goal of the reform program is to attract increased private investment in natural gas pipelines and other related facilities by fostering increased competition.[16]

Foreign companies are present in all aspects of the Australian natural gas market, from exploration and production to retail supply and marketing. U.S. oil company Chevron is developing the Australia Gas Pipeline Project to supply the unserved portion of northern Queensland with natural gas imported from Papua New Guinea. The pipeline will also connect to more populated areas of southern Queensland and the

[14] "Timor Sea Gas Prospects Improving," *Australian Energy News 14,* Dec. 1999, found at Internet address *http://www.isr.gov.au/aen/* retrieved Mar. 29, 2001.

[15] Australian Gas Association, *Australia's Gas Industry Overview*, found at Internet address *http://www.asn.org.au*, retrieved Jan. 31, 2001.

[16] "Developing a National Energy Market," *Australian Energy News 2,* Dec. 1996, found at Internet address *http://www.isr.gov.au/aen/*, retrieved Mar. 29, 2001.

increasingly interconnected transmission system that services southeastern Australia. This endeavor is in addition to Chevron's involvement in two major international joint-ventures to develop gas reserves off the northwest coast of Australia.[17] At over 2,600 kilometers (km), the Australia Gas Pipeline Project will be the longest pipeline in the southern hemisphere and connect the Australian market to over 6 trillion cubic feet of additional natural gas reserves.[18] Other offshore development projects have attracted other foreign companies. Participants in the North West Shelf Project include BP Amoco (U.K.), Royal Dutch/Shell (U.K.-Netherlands), Chevron, and Japan Australia LNG (Japan).[19] The Gorgon Project, which is developing another part of the fields off the Western Australian shore, is a consortium of Chevron, Texaco, ExxonMobil, and Royal Dutch/Shell.[20]

Transmission and Distribution

The Australian transmission network comprises more than 17,000 (km) of pipelines (figure 4-1). It is regulated by the national authority of the Australian Competition and Consumer Commission (ACCC). The ACCC is responsible for receiving and approving access arrangements submitted by service providers under the Code.[21]

By committing to interstate connection and the principles of market competition, Australia has attracted new private sector investments that are gradually forging an interconnected national natural gas pipeline system. Several transmission pipelines have recently been brought online that connect the markets of Victoria, New South Wales, South Australia, Queensland, and the Australian Capital Territory of Canberra, which account for 60 percent of total domestic consumption.[22] This promises to increase competition and reduce consumer prices within these markets.

The Northern Territory, Western Australia, and Tasmania remain to be connected to this regional market. While there are plans underway to develop gas fields off the Northern Territory and the Tasmanian coast, and connect both of these territories by pipeline to the market of southeastern Australia, the prospect of integrating Western Australia remains uncertain.

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[17] Chevron Overseas Petroleum Inc., found at Internet address *http://www.chevron.com,* retrieved Mar. 27, 2001.

[18] "Chevron Steps on the Gas," *Australian Energy News 9*, Sept. 1998, found at Internet address *http://www.isr.gov.au*, retrieved Mar. 29, 2001.

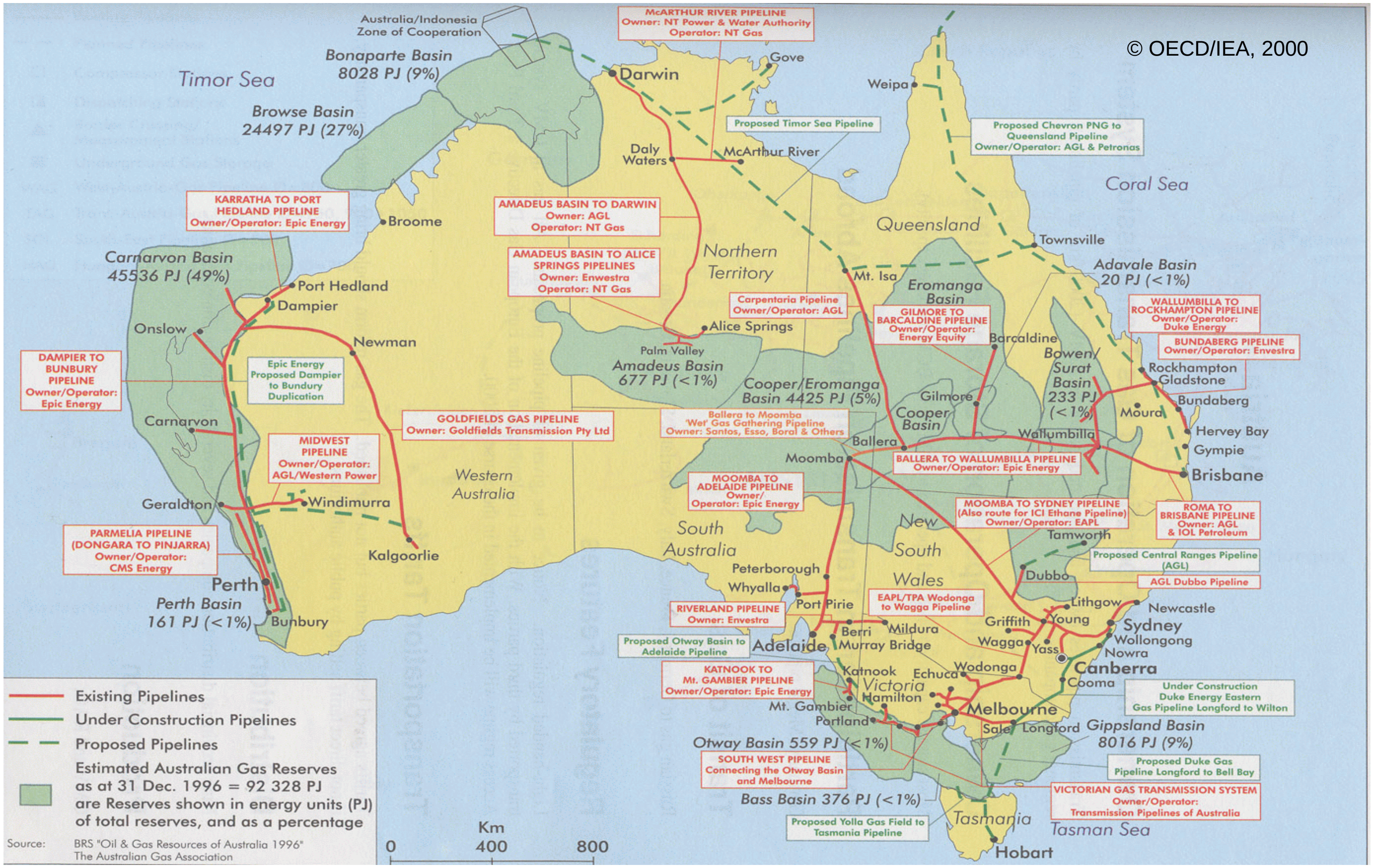
[19] "North West Shelf Consortium Approves Gas Extension," *The Financial Times*, Apr. 2, 2001, found at Internet address *http://www.ft.com,* retrieved Apr. 3, 2001. Domestic partners in the venture include BHP and Woodside, which is also the operator of the joint-venture.

[20] Found at Internet address *http://www.gorgon.com.au,* retrieved Mar. 21, 2001.

[21] Australian Competition and Consumer Commission, found at Internet address *http://www.accc.gov.au*, retrieved Jan. 31, 2001.

[22] Australian Gas Association, *Gas Statistics Australia 2000: Special Supplement*, Jan. 2001.

Figure 4-1
Natural gas pipelines in Australia



Source: Used with permission from the Organization for Economic Cooperation and Development, International Energy Agency. Maps obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition*.

The national transmission sector is served by at least 15 different companies or pipeline-specific joint ventures.[23] Foreign firms have a presence in the transmission sector by either operating wholly owned firms or by taking stakes in a domestic company. Among the U.S. firms owning and/or operating transmission facilities are Duke Energy International and TXU Networks (a subsidiary of Dallas-based TXU). Among foreign firms that have taken stakes in Australian companies, U.S. firm El Paso Energy Corporation holds a 33-percent share of Epic Energy, which operates in Western Australia, Queensland, and South Australia.

Australia's natural gas distribution networks extend over 70,300 km, serving 3.1 million households and 92,000 commercial and industrial customers.[24] There are at least 12 different companies, joint ventures, or other entities offering distribution services.[25] Although over 6 million residents receive gas services, accounting for nearly one-third of Australia's total population, less than 1 percent of gas customers use over 85 percent of the gas sold in Australia.[26]

There are four storage facilities in Australia. Three of these facilities are built specifically for storage and operated by private companies. Santos Limited (Australia) owns and operates a storage facility in the Cooper/Eromanga Basin in Moomba, South Australia. The Oil Company of Australia (Australia) owns and operates a facility in the Surat Basin at Newstead in southeastern Queensland. The third facility, owned and operated by CMS Gas Transmission of Australia, is at Mondarra, Western Australia on the Perth Basin.

The fourth storage facility utilizes the depleted Iona gas fields in the Otway Basin near Port Campbell, Victoria.[27] TXU Trading, a subsidiary of TXU's Australian operations, offers storage services to clients who wish to have gas withdrawn from the network and injected into a depleted basin of their own for express use as a reservoir. This type of service has created a "gas banking" business for TXU Trading in the absence of financial products typically found in more mature natural gas markets.[28]

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[23] Australian Gas Association, *Gas Statistics Australia 2000*, Aug. 2000.

[24] Australian Gas Association, *Australia's Gas Industry Overview*, found at Internet address *http://www.gas.asn.au*, retrieved Jan. 31, 2001.

[25] Australian Gas Association, *Gas Statistics Australia 2000*, Aug. 2000. Among the other entities are the Dalby Town Council and Roma Town Council, whose operations and facilities have been left uncovered by the Code.

[26] Australian Gas Association, *Australia's Gas Industry Overview*, found at Internet address *http://www.asn.org.au*, retrieved Jan. 31, 2001, and U.S. Department of State, *Background Notes: Australia*, Oct. 2000, found at Internet address *http://www.state.gov*, retrieved Jun. 4, 2001.

[27] Victorian Energy Networks Corporation (VENCorp), found at Internet address *http://www.vencorp.com.au*, retrieved Feb. 8, 2001.

[28] TXU Trading, found at Internet address *http://www.txu.com.au/trading*, retrieved Mar. 22, 2001.

Storage capacity in Australia is also available by using transmission and distribution lines for "line-packing."[29] When supply exceeds demand, excess pipeline capacity offers itself as a ready means of accumulating gas. This effectively allows for easy storage of inventory, referred to as linepack. In Victoria, where there are limited storage options, linepacking plays a vital role. Given the wholesale spot market operating in Victoria, the linepack inventory is monitored and managed on a daily basis.[30]

Markets and Pricing

Australia's reforms began the process of removing regulatory involvement in the determination of gas prices paid by consumers. Instead of paying regulated prices, producers and marketers negotiate wholesale supply contracts bilaterally, parts or all of which may be subsequently resold, or traded through an informal over-the-counter market. In practice, significant traded volume has developed only in Victoria, where a formal, centralized market for short-term transactions opened in March 1999. The Victorian spot market, operated by the state-owned, industry-funded Victoria Energy Networks Corporation (VENCorp), serves as a net pool for the trading of natural gas, allowing participants to buy and sell gas on a short-term basis. VENCorp acts as manager for this market, matching nominations (bids) and offers from market participants to inject or withdraw gas from the transmission system, which it also manages. VENCorp schedules the flow of gas according to the nominations, prevailing price, and specified quantities. VENCorp determines the "implied market clearing price" and manages the settlement of spot market trades.[31] Under the rules governing the spot market, a daily market price is set that applies to all participants' imbalances on that day irrespective of the location or time of day at which gas is injected or withdrawn.[32] A recent review of this policy has found there is not sufficient cause at this time to warrant locational/hourly pricing.[33] Regardless, the Victorian spot market accounts only for a small volume of supply, given the high volume of gas that continues to be supplied under long-term contracts. Throughout the rest of Australia, where spot markets have yet to develop, long-term supply contracts remain the standard.[34] Nonetheless, market participants are confident that

[29] Victorian Energy Networks Corporation (VENCorp), found at Internet address *http://www.vencorp.com.au,* retrieved Feb. 8, 2001.

[30] Victorian Energy Networks Corporation (VENCorp), found at Internet address *http://www.vencorp.com.au,* retrieved Feb. 8, 2001.

[31] VENCorp, found at Internet address *http://www.vencorp.com.au,* retrieved Apr. 6, 2001.

[32] VENCorp, *Victorian Gas Spot Market: Market Review Issues Paper*, Sep. 2000, found at Internet address *http://www.vencorp.com.au,* retrieved Jun. 7, 2001.

[33] VENCorp, *Review of Victorian Gas Market Arrangements*, Mar. 21, 2001, found at Internet address *http://www.vencorp.com.au*, retrieved Jun. 7, 2001.

[34] National Competition Council, "Free and Fair Trade in Gas: How Much has been Achieved?" speech by Ed Willett, Executive Director, Mar. 22, 1999.

spot markets will evolve further and be joined by a futures market as the competitive natural gas industry matures.[35]

At the retail level, marketers compete to serve eligible, or contestable, customers. Contestability is being phased in according to timetables established by each of the states and territories in their reform legislation. According to the Natural Gas Pipelines Access Agreement, full retail contestability will be phased in by consumer class, beginning with the largest industrial users based on annual consumption volume. With the exception of Western Australia, the transition period for full retail contestability ended Sept. 1, 2001. The transition period extends to July 1, 2002, for Western Australia (table 4-3). As they become eligible, consumers will be free to choose their gas marketer or negotiate bilateral contracts with suppliers. However, due to relatively low rates of per capita consumption, forecasts suggest that less than 25 percent of domestic customers will choose to change retailers.[36]

In addition to purchasing gas on behalf of their customers, marketers must also arrange for physical transportation. In general, transmission and distribution services are arranged through bilateral negotiation between the parties. This approach, called the contract carriage model, requires owners of pipelines covered under the Code to establish a reference tariff that meets with the approval of the regulatory authorities following a public consultation period.[37] Reference tariffs effectively establish a price ceiling for services contracted through each pipeline to which third-party access is assured under the access regime. They also seek to assure the facility owner a certain stream of revenue that "recovers the costs of delivering the Reference Service over the expected life of the assets used in delivering that Service, to replicate the outcome of a competitive market, and to be efficient in level and structure."[38]

Contracts for transmission and distribution capacity can subsequently be resold, or traded, through an informal over-the-counter market.[39] The Code also allows for contracting of transmission and distribution capacity under the market carriage model. This model is used only in Victoria, because it requires a centralized spot market in order to function. Under the market carriage model, the operator of the spot market allocates transmission capacity as required by gas market transactions, eliminating the need for market participants to contract for a specific quantity of

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[35] Gas Reform Implementation Group (GRIG), *Retail Competition in the Natural Gas Industry: Issues and Approaches*, Feb. 1999, found at Internet address *http://www.isr.gov.au*, retrieved Feb. 14, 2001.

[36] GRIG, *Consultation Paper: Issues Affecting Competition between Natural Gas Retailers*, July 1998, Found at Internet address *http://www.isr.gov.au*, Feb. 14, 2001.

[37] National Third Party Access Code for Natural Gas Pipeline Systems, Sec. 8.3, found at Internet address *http://www.coderegistrar.sa.gov.au*, retrieved Jan. 31, 2001.

[38] National Third Party Access Code for Natural Gas Pipeline Systems, Sec. 8, General Principles, found at Internet address *http://www.coderegistrar.sa.gov.au*, retrieved Jan. 31, 2001.

[39] Policy Information Paper, Gas Reform Implementation Group (GRIG), May 1998, found at Internet address *http://www.isr.gov.au*, retrieved Jan. 31, 2001.

Table 4-3
Timetable for retail contestability in Australia

	1996	1997	1998	1999	2000	2001	2002
	Minimum consumption threshold (terajoules)						
Australian Capital Territory	—	—	10	1	—	0	—
New South Wales	500	100	10	1	—	0	—
Queensland	—	—	—	—	—	0	—
Southern Australia	—	—	100	1	[1]0	[2]0	—
Victoria	—	—	—	500	10	0	—
Western Australia	—	500	250	—	100	—	0

[1] Industrial and commercial customers.
[2] Subject to review of technical and economic constraints.

Source: Australian Gas Association, *Gas Statistics Australia 2000*, Aug, 2000, p. 47.

capacity in advance. Charges are then based on actual usage of services.[40] The greater commercial flexibility of a spot market requires the greater flexibility provided by the market carriage model.[41] This occurs, for instance, in the informal secondary capacity market. However, market participants are confident, nonetheless, that secondary market trading involving spot, swap, capacity and futures markets will evolve naturally as the Australian market matures.[42]

The impact of reforms on prices has been mixed. This may be due to inconsistency and differences between reforms in various jurisdictions. This may also reflect the limited period for which the reforms have been in place, and the fact that reforms have not addressed each sector of the industry.[43] In Victoria, large industrial consumers that spend approximately A$70,000 annually on natural gas have saved less than 2 percent, or about A$1,200. This contrasts with savings from electric power reform of as much as 30 percent for large industrial consumers. Price reductions have been only marginally better for typical commercial users or residential users in Victoria, who have seen savings of 3.8 percent and 6.7 percent, on average annual bills of A$4,000

[40] *National Third Party Access Code for Natural Gas Pipeline Systems*, found at Internet address *http://www.coderegistrar.sa.gov.au*, retrieved Jan. 31, 2001.

[41] According to Sec 3.7(b) of the Code, a pipeline may only operate as a market carriage pipeline with the express approval of the "relevant minister" for the jurisdiction in which the pipeline operates.

[42] GRIG, *Retail Competition in the Natural Gas Industry: Issues and Approaches*, Feb. 1999, found at Internet address *http://www.isr.gov.au,* retrieved Feb 14, 2001.

[43] Reforming the upstream sector of exploration and production is being addressed separately by the Upstream Issues Working Group (UIWG), outside the framework of the Natural Gas Pipelines Access Agreement that pertains to the transmission, distribution and retail supply sectors. The limited decline in prices may also be better understood in light of the facts that pipeline delivery of gas constitutes only 15 percent of the total cost for some consumers. Existing long-term supply contracts that have yet to expire also limit the pool of gas open to competitive supply. Australian Gas Association, "Implications of downstream reform for the upstream sector," speech by Alan Beasley, Deputy Chief Executive, Oct. 1998, found at Internet address *http://www.asn.org.au*, retrieved Jan. 31, 2001.

and A$600, respectively.[44] Though price improvements have been forecast for other parts of the Australian natural gas market,[45] Victoria remains the largest and most mature market in Australia and, therefore, a potential bellwether.

Nonetheless, weighted price averages for the whole Australian natural gas market through 1998, the last year for which data are available, show declining prices. The weighted average price paid by residential consumers in 1998 of A$9.48 per gigajoule was down by about 11 percent from A$10.70 per gigajoule the year before, and down from A$10.21 per gigajoule in 1994. Commercial and industrial consumers paid a weighted average price of A$4.88 per gigajoule in 1998, down by almost 22 percent from A$6.22 in 1997, and down from A$6.11 per gigajoule in 1994.[46]

The Natural Gas Pipelines Access Agreement stipulated that all existing retail franchises would be phased out by September 1, 2001.[47] Any new exclusive retail franchise is restricted to a limited period and only for certain "greenfield" projects.[48]

Impediments to Competitive Market Development

Despite the reforms to the transmission, distribution, and retail supply sectors of the natural gas industry, there remain impediments to the development of an optimally competitive natural gas market in Australia.

One impediment is the limited pipeline interconnection of various local and regional markets into a genuine national natural gas market. There remains no pipeline connection from the wealth of supply in Western Australia and the majority of domestic demand in eastern Australia. The situation is compounded by the fact that existing transmission and interstate pipelines do not offer sufficient capacity to accommodate potential new entrants, hindering the development of a viable and competitive market presence.

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[44] Australian Gas Association, "Implications of downstream reform for the upstream sector," speech by Alan Beasley, Deputy Chief Executive, Oct. 1998, found at Internet address *http://www.asn.org.au*, retrieved Jan. 31, 2001.

[45] National Competition Council, "Free and Fair Trade in Gas: How Much has been Achieved?" speech by Ed Willett, Executive Director, Mar. 22, 1999, found at Internet address *http://www.ncc.gov.au*, retrieved Jun. 7, 2001.

[46] Australian Gas Association, *Gas Statistics Australia 2000*, Aug. 2000

[47] The only exception is a 10 year nonrenewable franchise of Kalgoorlie-Boulder in Western Australia. The transition phase ends in Western Australia on Jul. 1, 2002.

[48] National Competition Council, "Free and Fair Trade in Gas: How Much has been Achieved?" speech by Ed Willett, Executive Director, Mar. 22, 1999, found at Internet address *http://www.ncc.gov.au*, retrieved Jun. 7, 2001. According to Annex H of the National Gas Pipelines Access Agreement, greenfield investments will only qualify for franchise exclusivity if "there is evidence that investment in pipelines would not otherwise occur... and the franchise has been justified on the balance of public interest."

More importantly, there are a limited number of upstream producers/suppliers of natural gas.[49] Different parts of Australia are affected to varying degrees by this situation. Western Australia is isolated from the rest of the Australian market, but it benefits from nine different producers/suppliers. Elsewhere, especially in Southeastern Australia, recent interstate pipeline connections have yet to significantly overcome the original, pre-reform structure of the Australian natural gas market in which each State or territory supplied itself through its own pipeline from its proprietary basin. In Victoria, which is the largest and most developed consumer market for natural gas in Australia, over 98 percent of the gas consumed continues to come from the same field as before reform.[50]

By addressing only the transmission, distribution, and retail supply sectors, the National Gas Pipelines Access Agreement fails to resolve another impediment. Compared to more mature natural gas markets in the United Kingdom, Canada, and the United States, the depth of upstream competition among producers/suppliers is "very shallow."[51] The absence of upstream reforms adds intra-industry inconsistencies to jurisdictional inconsistencies. In response, the Upstream Issues Working Group (UIWG) was established in February 1998 to address the last and remaining sector. The UIWG was charged with reviewing all aspects of the upstream sector (the exploration and production business) that might affect the "growth, diversity, and level of competition in the downstream natural gas markets."[52] Specific issues under investigation included but were not limited to (1) access management systems, (2) third party access to upstream gas facilities, and (3) marketing arrangements. Procompetitive reforms on these issues would "encourage new players to enter the industry" and "boost competition between the existing parties within a basin." The work of the UIWG was specifically designed to be complementary to the reform process underway in the three downstream sectors covered by the National Gas Pipelines Access Agreement. It has been described as the "missing link" to the reform process and the achievement of competitive gas prices.[53] The final report of the UIWG was submitted in December 1998, but no action has resulted to date.

The presence of many foreign companies in joint-ventures or in their own independent undertakings, and in all sectors of the Australian natural gas industry, demonstrates a high level of market access and national treatment. While companies complain of

[49] VENCorp, *Review of Victorian Gas Market Arrangements*, Mar. 15, 2001. According to this paper, "retail competition is more likely to be influenced by limited access to supplies than by any particular feature of the transport management regime."

[50] Industry representative, interview by USITC staff, Tokyo, Japan, May 7, 2001. See also: Australian Gas Association, *Gas Statistics Australia 2000*, Aug. 2000, p. 98.

[51] Australia Gas Association, "Implications of Downstream Reform for the Upstream Sector," speech by Alan Beasley, Deputy Chief Executive, to the Upstream Gas Regulation and Competition Reform Conference, Oct. 1998, found at Internet address *http://www.asn.org.au,* retrieved Jan. 31, 2001.

[52] Department of Industry, Science and Resources, Upstream Issues Working Group, *Report to Ministers*, Dec. 1998, found at Internet address *http://www.isr.gov.au*, retrieved Feb. 14, 2001.

[53] National Competition Council, "Free and Fair Trade in Gas: How Much has been Achieved?" speech by Ed Willett, Executive Director, Mar. 22, 1999, found at Internet address *http://www.ncc.gov.au,* retrieved Jun 7, 2001.

excessive paperwork and bureaucracy resulting from the reforms, this administrative burden is not limited to foreign firms.

Australia does maintain a Foreign Investment Review Board (FIRB) to adjudicate on issues raised by proposed foreign investment in Australian companies or resources. It is self-described as a very liberal regime.[54] However, a recent decision against the hostile bid by Royal Dutch/Shell for Woodside Energy, domestic operator of the North West Shelf Project, demonstrates that national treatment is not guaranteed in all cases. The FIRB cited national interest, given Woodside's position as the country's largest energy producer and the importance of the North West Shelf gas reserves.[55]

[54] Foreign Investment Review Board, found at Internet address *http://www.treasury.gov.au/firb*, retrieved Apr. 5, 2001.

[55] Becky Gaylord, "Australia Rejects a Shell Takeover Bid," found at Internet address *http://www.nytimes.com*, retrieved Apr. 24, 2001.

CHAPTER 5
BRAZIL

Overview

In recent years, the growth in energy demand has exceeded the growth in supply in Brazil, while prolonged drought has exposed Brazil's dependency on hydroelectric plants that supply more than 90 percent of the country's electric power. Accordingly, the Brazilian Government has begun reforms to accelerate the discovery, development, and use of natural gas to achieve a more stable energy balance in an environmentally prudent[1] manner.[2] Brazil's natural gas reserves of approximately 8 trillion cubic feet (tcf), chiefly in the Campos Basin of Rio de Janeiro State and in the States of Bahia and Amazonas, are considered modest.[3] Nevertheless, the Government plans to rely on natural gas for 12 percent of its total energy consumption by 2010, although the sector accounted for less than 3 percent of this total in the early 1990s.[4] At present, however, the path, extent, and pace of further market reforms in natural gas are uncertain, in part because of events and trends in other energy sectors.

An immediate energy concern in Brazil is the inadequacy of electricity supply. After several years of attempts to encourage firms to invest in energy projects, including gas-fired generation plants, a Thermoelectric Priority Program was established by Decree 3371 in 2000.[5] Under the program, 49 gas-fired plants were to be developed and made operational by 2007, with 28 top-priority plants intended to be available by 2003, supplied by recent and on-going expansion in gas pipelines. However, private investors are hesitant to build these plants, given unclear investment rules and potentially large cost recovery issues discussed later in this chapter. As of June 2001, at most 10 plants were under construction, and few, if any, are likely to be

[1] Natural gas consisting mainly of methane gas burns cleanly and uniformly, without producing soot or other agents harmful to the environment. "The ecologically correct fuel," Gaspetro, natural gas information, found at Internet address *http://www.gaspetro.com*, retrieved Feb. 9, 2001.

[2] Government official, State of Sao Paulo, interview by USITC staff, Sao Paulo, Brazil, May 9, 2001.

[3] U.S. Department of Energy (USDOE), Energy Information Administration (EIA), *Brazil*, June 2000, found at Internet address *http://www.eia.doe.gov/emeu/cabs/brazil.html*.

[4] *World Gas Handbook 2000*, 2nd ed. (New York, NY: Energy Intelligence Research and World Gas Intelligence, Feb. 2000), p. 39.

[5] "Energy Sector: Highlights in 2000 and Business Opportunities," report of Ministry of Mines and Energy, Government of Brazil, in *Economy & Energy*, No. 25, Mar.-Apr. 2001, found at Internet address *http://ecen.com/matriz/eee25/ener200e.htm*, retrieved June 1, 2001.

operating by year-end 2001.[6] Thus, gas pipeline capacity, expanded in anticipation of supplying thermoelectric plants, lies unused. In June 2001, in an effort to institute energy conservation and avoid widespread power outages, the Government implemented a rationing plan requiring consumers to reduce electricity use by an average of 20 percent.[7] As a result, certain energy market reforms have slowed or been revised, awaiting further indications of market conditions and the outlook for investment.

The natural gas industry in Brazil is a fledgling market[8] and its position in the petroleum sub-sector frames its institutional and regulatory environment. Most gas reserves occur in association with oil. Historically, hydrocarbon exploration activity reflected the Government's goal that Brazil become more self-sufficient in petroleum, and natural gas was regarded as secondary. Reform in Brazil's oil and gas industries began in 1995 with the adoption of amendment No. 9 to the Federal Constitution that removed restrictions on the participation of private capital in the sector. The amendment removed the right of exclusivity provided to Petróleo Brasileiro S.A. (Petrobras), a monopoly firm owned by the Brazilian Government,[9] to perform exploratory, developmental, and production-related (upstream) activities, as well as conduct importing and exporting, refining, and transporting (midstream) activities of oil and gas in Brazil.

In 1997, the Brazilian Government enacted the Petroleum Investment Law (Law 9478), which set limits on the Federal Government's holdings in Petrobras and created a new regulatory entity, Agência Nacional do Petróleo (ANP)[10] The law provided for negotiated third-party access to oil and gas infrastructure, and allowed companies established under Brazilian law and with headquarters and management in Brazil to import and export hydrocarbons, subject to regulatory authorization.[11]

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[6] Industry representatives, interviews by USITC staff, Sao Paulo and Rio de Janeiro, Brazil, May 2001.

[7] As of August 2001, the rationing plan was applied in all regions of Brazil, except in the southern states of Rio Grande do Sul, Santa Catarina, and Parena. USDOC, ITA, "Update: Power Rationing in Brazil, August 2001", International Market Insight Report, Sept. 5, 2001, found at Internet address *http://www.stat-usa.gov/*, retrieved Sept. 7, 2001.

[8] Natural gas was introduced for consumption in Brazil in 1988. Small quantities were provided to Sao Paulo from local oil fields through a distribution network originally constructed for manufactured gas. Peter L. Law and Nelson de Franco, "International Gas Trade -- the Bolivia-Brazil Gas Pipeline," World Bank Group, 1999, found at Internet address *http://www.worldbank.org/*, retrieved Jan. 24, 2001.

[9] Under Brazil's Constitution, majority ownership in Petrobras must remain with the Federal Government. The Government owns 84 percent of the firm's voting shares, having sold a minority interest in the firm through a public offering of shares of stock in 2000, raising $4 billion. BNDES, "Privatization," data and history, found at Internet address *http://www.bndes.gov.br/english*, retrieved Feb. 12 and 16, 2001.

[10] Peter L. Law and Bent R. Svensson, "Gas Sector Restructuring and Privatization: Lessons from Argentina, Brazil, Poland, Hungary, and Vietnam," ch. in *Natural Gas: Private Sector Participation and Market Development 1999* (Washington, DC: World Bank, 1999), p. 23.

[11] Government official, interview by USITC staff, Rio de Janeiro, Brazil, May 15, 2001.

Nevertheless, no restrictions were placed on cross-ownership in the gas chain, affording Petrobras considerable flexibility to operate in various energy segments.

ANP will oversee the process of the petroleum and natural gas sector's transition from exclusive ownership and control by Petrobras of upstream and midstream activities. ANP began operating in 1998,[12] with jurisdiction over oil and gas exploration, production, and transportation,[13] including activities such as licensing, inspection, and contract arbitration in instances of disputes. ANP established criteria for the calculation of transportation tariffs, but does not set specific tariffs except when necessary to arbitrate disputes concerning tariffs.[14] The agency is considered professional, objective, transparent in its processes, growing in experience, and striving to improve the clarity of its regulations.[15] A recent example includes ANP's revisions of open-access rules, during which ANP elicited and published comments from the industry, in connection with gas provided through the Bolivia-Brazil pipeline.

Industry Structure

Production and Imports

Petrobras is the only firm currently producing natural gas in Brazil.[16] At the start of 2001, Petrobras operated 78 exploratory blocks, 44 fields of production development, and 239 fields in production. In 2000, average daily natural gas production in Brazil amounted to 36.4 million cubic meters, which surpassed the production volume in 1999 by 125 percent. Of the total production in 2000, only about half was available for commercial sale, while the remainder was re-injected, flared off for lack of a market, or consumed internally as an energy source and raw material in Petrobras' activities.[17]

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[12] ANP is governed by a board of five directors nominated by the President of Brazil and confirmed by the Federal Senate. The directors cannot have had connections with firms in the oil and gas sector for a year prior to taking office. Joao Afonso da Silveira de Assis and Marcello Oliveira, "The New Legal Regime for the Petroleum Industry in Brazil," Dec. 15, 1998, found at Internet address *http://www.gasandoil.com/goc/speeches/petroleumlawbrazil.htm,* retrieved Mar. 1, 2001.

[13] Law 9478 distinguishes between "transportation," meaning shipments over routes considered to be of general interest, and "transfer," which refers to shipments over routes considered of specific and exclusive interest. Government official, interview by USITC staff, Rio de Janeiro, Brazil, May 15, 2001.

[14] Government official, interview by USITC staff, Rio de Janeiro, Brazil, May 15, 2001.

[15] Industry representatives, interviews by USITC staff, Sao Paulo, Brazil, May 9-10, and Rio de Janeiro, Brazil, May 15-17.

[16] *World Gas Handbook 2000*, p. 39.

[17] "Energy Sector: Highlights in 1999 and Business Opportunities," report of secretariat of Energy, Ministry of Mines and Energy, Government of Brazil, in *Economy and Energy*, No. 19, Apr.-May 2000, found at Internet address *http://ecen.com/eee19*, retrieved Feb. 14, 2001.

The monopoly position of Petrobras in upstream production ended in June 1999, as ANP launched the first round of bidding for concessions authorizing foreign and Brazilian firms, including Petrobras, to explore for and develop petroleum and natural gas.[18] In the first round, ANP offered 27 large exploration blocks, of which 12 were awarded.[19] A second round of concessions followed in 2000, with ANP awarding 21 of 23 blocks offered. As a result of the first two rounds, about 35 firms -- 28 foreign and 7 Brazilian, including Petrobras -- are now active in exploration in Brazil, operating alone or participating in consortia in exploratory blocks. Petrobras participates in 13 consortia and operates exclusively in 10 additional blocks awarded by ANP in the first 2 rounds. In blocks in which it has a partnership interest, Petrobras is regarded positively in terms of expertise and collaboration in exploration and development by partner firms.[20] U.S. firms among the concessionaires in the first two rounds include Amerada Hess, Chevron, El Paso (through the purchase of Coastal), Kerr McGee, Sante Fe, Texaco, Union Pacific, and Unocal.[21] A third round, consisting of smaller blocks than in the first two rounds, was held on June 19-20, 2001.[22] This most recent tender offer of oil and gas exploration licenses attracted winning bids from both large firms and small independent companies. Although Petrobras again purchased the most blocks of the 53 offered for bid, U.S. firms, notably El Paso Energy and Phillips, participated significantly.[23]

Brazil imports a considerable volume of natural gas through international pipelines from Bolivia and Argentina, and plans are underway to construct an LNG receiving terminal and storage facility, to be jointly owned by Petrobras and Shell (U.K.).[24]

Transmission and Distribution

Brazil's international pipelines essentially serve as the backbone of the nascent transmission network (see figure 3-1). In 1992, Brazil and Bolivia signed an accord for Bolivia to supply natural gas through a nearly 2,000-mile pipeline from Santa Cruz in Bolivia initially to Campinas in the State of Sao Paulo and subsequently to Porto Alegre in the State of Rio Grande do Sul, Brazil.[25] Natural gas imported from Bolivia through the Bolivia-to-Brazil pipeline (Gasbol) is intended chiefly as a fuel for

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[18] "Energy Sector: Highlights in 2000 and Business Opportunities."

[19] Government official, interview by USITC staff, Rio de Janeiro, Brazil, May 15, 2001.

[20] Industry representatives, interviews by USITC staff, Rio de Janeiro, Brazil, May 15-16, 2001.

[21] Industry representative, interview by USITC staff, Rio de Janeiro, Brazil, May 16, 2001, and "Energy Sector: Highlights in 2000 and Business Opportunities."

[22] Government official, interview by USITC staff, Rio de Janeiro, Brazil, May 15, 2001.

[23] ANP, "Results, Brazil Round Three," found at Internet address *http://www.brazil-round3.com/round3/,* retrieved June 21, 2001.

[24] Industry representative, interview by USITC staff, Rio de Janeiro, Brazil, May 16, 2001.

[25] Natural gas through the pipeline will be distributed in the States of Mato Grosso do Sul, Sao Paulo, Parana, Santa Catarina, and Rio Grande do Sul, which together account for 82 percent of Brazil's industrial production and 71 percent of energy consumption. Moreover, the States of Minas Gerais and Rio de Janeiro will be connected through separate branches to the B-to-B pipeline. "Energy Sector: Highlights in 1999 and Business Opportunities."

electric power generation facilities in the southern and western regions of Brazil.[26] The pipeline cost $2.1 billion to construct,[27] and was the first major gas infrastructure project involving the private sector in Brazil. Private interests own 57 percent of the entire pipeline, including 49 percent of the Brazilian portion. The Bolivian and Brazilian firms formed to implement the pipeline included participation by leading international oil and gas firms. Funding was provided by these firms as well as from numerous national and multinational sources.[28] The main trunk line was completed in December 1998, and gas began to flow through to Campinas under take-or-pay contracts in July 1999. The second phase provided gas to Porto Alegre beginning in 2000. The Gasbol pipeline is operated by Transportadora Braileira Gasoduto Bolívia-Brasil S.A. (TBG), which is jointly owned by Petrobras through its subsidiary Gaspetro, along with a number of international private sector firms.[29] In its first 6 months of operation, the pipeline transported about 2 million cubic meters of gas per day. This volume is projected to expand to a maximum capacity of 30 million cubic meters per day by 2004.

Further efforts to increase access to natural gas in Brazil include additions to the 273-mile pipeline from Parana, Argentina, to Uruguaiana, Brazil.[30] This pipeline, which entered into service in 2000, provides natural gas to a thermoelectric plant owned by AES (U.S.). A 370-mile extension of this pipeline to Porto Alegre, Brazil, is under construction, with completion anticipated in 2002.[31] A trans-Iguacu pipeline from northern Argentina into southern Brazil and a pipeline from northwest Argentina to Curitiba, Brazil, and from there to Sao Paulo state are under study. Moreover, Petrobras reportedly is considering construction of another pipeline from Bolivia, linking Petrobras' owned-and-operated gas fields in Bolivia to markets in Brazil. In so doing, Petrobras could bypass the existing Gasbol pipeline, leaving other firms to absorb contractually obligated costs to transport gas in the current pipeline from Bolivia.[32] In northern Brazil, pipeline extensions and connecting links to existing lines are under construction. In western Brazil, pipeline extensions are under construction in several directions, to be connected to the existing pipeline from Urucu to Coari.

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[26] "Bolivia-Brazil Pipeline," Government of Bolivia, news release, found at Internet address *http://www.energia.gov.bo/,* retrieved Feb. 7, 2001.

[27] The Gasbol pipeline involved financing from the World Bank, the Inter-American Development Bank, the Andean Development Corporation, and the European Investment Bank, among others. "The World Bank Helps Finance A Gas Pipeline Project Between Bolivia and Brazil," World Bank, press release No. 98/1588/LAC, Dec. 18, 1997, found at Internet address *http://www.worldbank.org/*, retrieved Sept. 11, 2001.

[28] Among others, partners included Transredes, a joint-venture formed by Enron and Shell.

[29] Stockholders in the partnership include BBPP Holdings (British Gas, El Paso Energy, and BHP), Enron, Shell, and others. "Financing," Petrobras news, found at Internet address *http://www.petrobras.com.br/,* retrieved Feb. 9, 2001.

[30] Law and de Franco, "International Gas Trade -- the Bolivia-Brazil Gas Pipeline," p. 37.

[31] Industry representative, interview by USITC staff, Rio de Janeiro, Brazil, May 16, 2001, and "Energy Sector: Highlights in 2000 and Business Opportunities."

[32] USDOE, EIA, *Bolivia*, July 2000, found at Internet address *http://www.eia.doe.gov/emeu/cabs/bolivia.html,* retrieved Sept. 11, 2000.

Prior to Gasbol's completion, Brazil had 650 miles of natural gas pipelines[33] in several, mainly coastal, regions. Petrobras solely owns and operates the internal Brazilian natural gas transmission infrastructure through its subsidiary Transpetro.[34]

Under the Brazilian Constitution, local distribution of natural gas transported by pipelines is the responsibility of Brazilian state governments. In the late 1990s, states began to offer their distribution companies to Brazilian and non-Brazilian firms as concession areas in accordance with the Petroleum Investment Law. In 1997, the Federal Government permitted states to accelerate their privatization efforts. Accordingly, in that year, Shell (U.K.-Netherlands) purchased a minority 19.5-percent stake in the largest Brazilian natural gas distribution company, COMGAS (Sao Paulo), and the State of Rio de Janeiro privatized its two distribution companies, CEG and CEG Rio (formerly Rio Gás S.A.).[35] In 1999, controlling interest in COMGAS[36] was awarded to British Gas (U.K.) and a concession to operate Gás Noroeste in northeast Sao Paulo State was auctioned to Italgas and Snam (Italy). In 2000, the State of Sao Paulo auctioned a concession to Gas Natural to operate the gas distribution company SULGAS in the southern portion of the state.[37] In both Rio de Janiero and Sao Paulo, the concession period is 30 years, with concessionaires receiving exclusivity to market natural gas to all consumers within the designated region during the first 12 years as a means to ensure an adequate return on investment. The two newest concessions in Sao Paulo State, outside metropolitan Sao Paulo, require concessionaires to build pipelines to serve new, primarily industrial customers. In the City of Sao Paulo, sales by COMGAS have increased by 70 percent since privatization began, largely from industrial customers.[38] Further sales growth is anticipated as existing power plants are converted to natural gas and new gas-fired power plants are constructed. In Rio de Janeiro State, concessionaires are obligated to upgrade existing pipelines, as they serve primarily residential customers, but are not required to build new pipelines. Nevertheless, the concessionaires may apply to the state's regulatory agency for authorization to do so.[39]

Aside from the States of Sao Paulo and Rio de Janeiro, other Brazilian States have not divested their ownership of natural gas distribution companies. Further privatization

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[33] USDOE, Office of Fossil Energy (FE), "An Energy Overview of Brazil," found at Internet address *http://www.fe.doe.gov/international/brazover.html*, retrieved Feb. 7, 2001.

[34] "Transpetro Gets Autonomy," *Brasil Energy*, May 2000, found at Internet address *http://www.brasilenergia.com.br*, retrieved Mar. 21, 2001.

[35] The winning bid for the Rio de Janeiro distribution companies was submitted by a group of firms including Enron (45 percent) and Spanish firms Gas Natural (33.5 percent) and Iberdrola (17.5 percent). USDOE, FE, "An Energy Overview of Brazil."

[36] British Gas (U.K.) acquired 72 percent of COMGAS, while Shell and several electricity distribution companies own the remainder.

[37] The State of Sao Paulo no longer owns a financial stake in natural gas distribution companies, which distinguishes it from all other Brazilian states. Industry representative, interview by USITC staff, Sao Paulo, Brazil, May 9, 2001.

[38] Industry representative, interview by USITC staff, Sao Paulo, Brazil, May 9, 2001.

[39] Government officials, State of Rio de Janeiro, interview by USITC staff, Rio de Janeiro, Brazil, May 14, 2001.

of state natural gas distribution companies is anticipated,[40] and several states are studying Sao Paulo State's regulatory system for possible application. Initially, however, each state must enact legislation to allow privatization of natural gas assets, a potentially lengthy process which few have undertaken.[41] Among the factors believed to inhibit such privatization is the scarcity of potential industrial customers to be served in other areas of Brazil, especially in the north, contrasted by the heavy concentration of industrial customers to be served by natural gas in the southeast, where privatization has occurred. Insufficient regulatory autonomy from state governments and local distribution companies' political influence within the states are also factors potentially slowing reform at the state level.[42] Petrobras owns minority stakes in about 14 of the 18 Brazilian natural gas distribution companies, and reportedly plans to increase investments in such firms.[43]

Markets and Pricing

Brazil's reforms have begun to lay the foundation for the development of a competitive market for natural gas.[44] The end of the exploration and production monopoly may eventually allow natural gas prices to be determined by offers from competing producers. The introduction of third-party access to transmission pipelines encourages new construction of pipeline capacity and could eventually permit producers and marketers to compete broadly for customers. However, until the new competitors to Petrobras in exploration and development concessions begin producing, Petrobras will remain the sole domestic producer. As a result, imports offer the only competitive source of supply, which means that in practice only large industrial consumers, powerplants, and local distribution companies have the option of choosing an alternative supplier. Thus far, there have been two cases where customer choice was exercised, both concerning the Gasbol pipeline. In 2000, Enron (U.S.) received authority from ANP, over Petrobras objections, to import up to 1 million cubic meters of gas per day on an interruptible basis for Enron's thermoelectric plant in Cuiaba, Brazil.[45] In 2001, ANP also upheld its earlier decision to allow British Gas to import

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[40] "Tractebel Plans to Expand into Energy and Gas Distribution," *Gazeta Mercantil*, Apr. 27, 2001.

[41] Industry representative, interview by USITC staff, Sao Paulo, Brazil, May 11, 2001.

[42] Industry representative, interview by USITC staff, Sao Paulo, Brazil, May 10, 2001.

[43] Petrobras will likely purchase Enron's 25-percent stake in CEG (Rio de Janeiro) in the near future, adding to the 16.3-percent Petrobras already owns. Brazilian attorney, interview with USITC staff, Rio de Janeiro, May 15, 2001, and *Wall Street Journal*, May 1, 2001, p. A21.

[44] Government official, State of Sao Paulo, interview by USITC staff, Sao Paulo, Brazil, May 9, 2001.

[45] At present, however, a separate challenge to Enron's previously approved environmental license has caused the company to continue to operate the plant by using diesel fuel, while Enron's pipeline to serve the plant is re-routed to bypass environmentally sensitive territory. Industry representative, interview by USITC staff, Sao Paulo, Brazil, May 9, 2001.

Bolivian gas through the Gasbol pipeline into Brazil.[46] Upon signing contracts, British Gas could import 1 million cubic meters daily into Sao Paulo State for sale to COMGAS.

For the most part, consumers and local distribution companies continue to source all of their natural gas from Petrobras' transmission affiliate Gaspetro, and Brazil has yet to define a timetable for the introduction of competition. Meanwhile, the Ministry of Finance and the Ministry of State for Mines and Energy will continue to regulate natural gas production prices,[47] and ANP will continue to regulate transmission and distribution prices. Industry sources indicate that large consumers using more than 500,000 cubic meters per day and thermoelectric plants may be able to choose their natural gas supplier following the 12-year exclusivity period when it is envisioned that a wholesale market for gas may be established.

The gas commodity price at the initial entry point of the transporting pipeline is determined according to a formula that takes into account exchange rate variations for imported gas, the national inflation index, and world fuel oil prices. The transportation charge currently is uniform throughout Brazil. The determination of differentiated transportation costs for each state based on a distance formula is expected to be introduced nationally in the second half of 2002.[48] Adjustments to transportation costs based on an inflation index are expected to be set yearly. In some areas, large users close to refineries pay little or no transportation costs, as they may bypass the Petrobras-owned transmission pipelines.[49]

Impediments to Competitive Market Development

The Brazilian Government's primary objective appears to be to expand natural gas production and pipeline transportation as a means of supplying new gas-fired electric power plants, and thereby mitigating the current electric power crisis. To pursue this objective, Brazil is more concerned with encouraging private investment, domestic and foreign, than with fostering competition. This strategy may extend the amount of time required to develop a competitive market, as privatization programs have included lengthy transition periods during which the new owners enjoy a monopoly over all gas sales within their region.

Another impediment to market development is the foreign exchange risk faced by gas-fired power plant developers. Electricity is billed to customers in Brazilian currency,

[46] "Regulator Authorizes Enron and British Gas To Use Brazil-Bolivia Gas Pipeline," *Gazeta Mercantil*, Feb. 14, 2001, found at Internet address *http://www.gazetamercantil.com,* retrieved Feb. 14, 2001.

[47] Government of Brazil, Ministry of Mines and Energy, "Inter-Ministerial Ruling No. 3, dated February 17, 2000," found at Internet address *http://www.gaspetro.com.br/ingles/portaria.htm,* retrieved Feb. 9, 2001.

[48] Industry representative, interview by USITC staff, Rio de Janeiro, Brazil, May 16, 2001.

[49] Government official, State of Rio de Janeiro, interview by USITC staff, Rio de Janeiro, Brazil, May 14, 2001.

the real, but purchases of natural gas, whether imported or domestically produced, as well as of equipment, and construction and maintenance services, must be paid in U.S. dollars. Potential investors, including U.S. firms with affiliates in Brazil, cited the 40-percent devaluation of the real in 1999 and continued decline in value against the U.S. dollar in the first half of 2001 as a major deterrent to investment,[50] noting that the annual tariff adjustment in the natural gas price set by the Brazilian Government could not provide sufficient hedge against currency risk.[51] However, warnings from advisors and the energy industry about looming energy shortages for many years, coupled with low incentives for investment, have finally obliged the Government to react. With the onset of electricity rationing, the Government introduced a plan for Petrobras to absorb the risk of foreign exchange fluctuations and related financial costs for 1 year, without passing them through to gas distribution companies, which likewise would not pass them on to power producers.[52] At the end of the year, Petrobras would be compensated for exchange rate losses incurred, most likely through additions to tariffs paid by consumers. It remains to be determined whether the Petrobras risk-absorption program will sufficiently stimulate investment, given that the exchange risks associated with thermoelectric plant construction persist. Such investments are expected to stabilize, but are unlikely to increase in the near future.[53]

In addition, the market power of Petrobras is frequently cited as a likely impediment to market development in Brazil’s midstream and downstream natural gas sector. Petrobras is perceived as usually successful in contract negotiations with customers, in part because its dominant participation in the supply and purchase of gas through the Gasbol pipeline affords considerable price flexibility.[54] Additionally, the broad role of Petrobras throughout the energy supply and delivery chain in Brazil and Bolivia is demonstrated in its ownership of electric power generation plants in both countries. Moreover, increasing participation by Petrobras in natural gas distribution companies is believed to foreshadow a more difficult regulatory environment for individual Brazilian State regulators, most of which are hampered by limited experience and resources.[55] Petrobras is regarded favorably by some industry participants for successfully representing certain concerns in deliberations with other government entities. Moreover, the cost to Petrobras of absorbing foreign exchange

[50] In 1997, the Brazilian real was nearly at par with the U.S. dollar. As of early June 2001, the exchange value hovered around 2.35 real to the dollar.

[51] Industry representatives, interviews with USITC staff, Sao Paulo and Rio de Janeiro, Brazil, May 2001.

[52] U.S. Department of Commerce, International Trade Administration, “New Gas/Credit Account: Thermal Power Plants,” International Market Insight report, May 4, 2001, found at Internet address *http://www.stat-usa.gov/,* retrieved May 23, 2001.

[53] U.S. Department of Commerce officials, interviews by USITC staff, Sao Paulo and Rio de Janeiro, Brazil, May 2001.

[54] Industry representatives, interviews with USITC staff, Sao Paulo and Rio de Janeiro, Brazil, May 2001.

[55] Industry representatives and state government officials, interviews with USITC staff, Sao Paulo and Rio de Janeiro, Brazil, May 2001.

risk and construction, maintenance, and repair expenses in connection with gas transmission appear to justify granting Petrobras adequate returns through tariffs.[56] Petrobras' continued ties to the Government are mandated by the Brazilian Constitution, despite the sale in 2000 of a minority interest in the firm in a $4-billion public stock offering.[57] There is ample evidence that Government ties with Petrobras remain strong. For example, the Government still controls 84 percent of Petrobras' voting shares; Brazil's Minister of Mines and Energy is the firm's board chairman; and the Government has instructed Petrobras to become a major investor in more than half of Brazil's newly authorized thermoelectric power plants.[58]

Other difficulties that may impede competitive market development include Brazil's multi-layered aggregated taxes that inflate prices of all services and goods, the protracted processes required for the issuance of environmental and import licenses,[59] and challenges to signed and implemented contracts arising from varying interpretations of the Federal Constitution and legislation of individual states. Moreover, the pace of selling or offering concessions in Brazilian energy firms has slowed. Also, the privatization model used in previous reforms in electricity and other industries in Brazil which included transfer of ownership and/or operational control has been replaced most recently by plans to offer non-controlling amounts of shares to individual investors. In such an evolving privatization model, the process by which an interested firm may secure operational control from an individual state or the Federal Government is unclear, as are the rights of private-company investors limited to taking a minority stockholding.

Private investment in new pipeline capacity has been slow to develop in Brazil, in part due to unclear regulations. Among the difficulties with previous open access rules adopted by ANP in 1998 was the stipulation that only Petrobras could expand the Gasbol pipeline capacity. ANP subsequently proposed new open access rules, expected to be finalized soon after receiving detailed input from industry, which would allow any company to access or expand any existing gas pipeline, subject to a review process that includes the applicant's submission of a feasibility study.[60] Moreover, capacity allocation procedures, rules on re-sale of previously contracted capacity in the absence of a spot market, and standards for available capacity offered on a noninterruptible basis are included in the new proposed regulations, among other improvements.

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[56] Industry representatives, interviews by USITC staff, Rio de Janeiro, Brazil, May 15-16, 2001.

[57] BNDES, "Privatization - History," found at Internet address *http://www.bndes.gov.br/english/priv8.htm,* retrieved Feb. 16, 2001.

[58] U.S. Department of State telegram, "Petrobras - the Investment," message reference No. 301, prepared by U.S. Consulate, Rio de Janeiro, Mar. 1, 2001.

[59] Unfamiliarity by state regulatory authorities with features and ramifications of take-or-pay/ship-or-pay contracts has delayed importation of certain natural gas supply. U.S. Department of Commerce official, interview by USITC staff, Rio de Janeiro, May 14, 2001.

[60] Government officials, interview by USITC staff, Rio de Janeiro, Brazil, May 15, 2001.

CHAPTER 6
CANADA

Overview

Owing to significant deregulation by both Federal and Provincial Governments over the past two decades, Canada has possibly the most open natural gas market in the world,[1] with competition extending from production to final consumer marketing in much of the country. Canada's energy policy reflects a sharp constitutional division of power between the Federal and Provincial Governments. Energy resources, including natural gas, within the Provinces belong to the Provinces, whereas those in the territories and in offshore areas belong to the Federal Government.[2] As a result, natural gas regulation is primarily under the jurisdiction of the Provinces, which have responsibilities concerning production, processing, intra-Provincial transmission, distribution, and marketing. Federal Government jurisdiction is limited to international trade and interprovincial transmission. As such, regulatory reform has proceeded at the discretion and pace of the various Provinces. To date, production of natural gas is fully competitive, and the Provinces have moved toward effective market competition in the downstream gas markets.

The introduction of competition in Canada's natural gas market began on October 31, 1985, when the Government of Canada and the three primary gas-producing Provinces of British Columbia, Alberta, and Saskatchewan signed the Agreement on Natural Gas Prices and Markets. This agreement allowed gas buyers to purchase natural gas directly from producers, marketers, and other agents at negotiated prices. Prior to the agreement, the price of natural gas sold in interprovincial trade was regulated by joint agreement between the Federal Government and Alberta, the largest supplier of Canada's natural gas, and the price of gas sold within the producing Provinces was regulated by the Provincial Governments.[3] Further, prior to the agreement, gas buyers in non-producing Provinces could purchase gas only at a "bundled" price, which included the cost of gas plus transportation.[4]

While the agreement created the necessary conditions for the establishment of a competitive natural gas market, the transmission sector continues to be regulated owing to its natural monopoly characteristics. As a result, the Agreement directed the National Energy Board (NEB) to ensure that open, nondiscriminatory, third-party

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[1] Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA), *Energy Policies of IEA Countries: Canada 1996 Review* (Paris: OECD, 1996), p. 61; and OECD, IEA, *Energy Policies of IEA Countries: Canada 2000 Review* (Paris: OECD, 2000), p. 10.

[2] Ibid., p. 31.

[3] National Energy Board (NEB), *Natural Gas Market Assessment* **-** *Ten Years after Deregulation*, 1996, p. 1.

[4] Ibid., p. v.

access is provided to all shippers on interprovincial gas pipelines and to regulate interprovincial transportation rates, conditions of access, and terms of service.[5]

The NEB also grants licenses for the long-term export of natural gas after ensuring that such exports will not result in domestic gas shortages. In July 1987, the NEB adopted the Market-Based Procedure (MBP) to make that assessment. The procedure assumes that markets are competitive, market power is not abused, and all buyers have access to gas on similar terms and conditions.[6]

Provincial public utility commissions regulate the rates of the local distribution companies (LDCs) and intra-Provincial transmission pipelines. The commissions also authorize construction of transmission and distribution lines and the establishment of franchise areas. The commissions impose few conditions on agents, brokers, and marketers other than multiyear supply requirements[7] and the posting of bonds.[8] In the event of a supply disruption from someone other than the LDC, the LDC is the supplier of last resort.

With the exception of one pipeline and a few local distribution systems, the natural gas industry in Canada is essentially a privately owned industry. Restructuring appears to have been primarily vertical as LDCs have been separated from producing and transmission companies, and a marketing sector has developed. Choice appears to be available to many industrial, commercial, and residential natural gas consumers in Canada, but is largely absent for residential customers in most Provinces.

Industry Structure

Production and Imports

Canadian natural gas reserves are concentrated primarily in the Western Canada Sedimentary Basin, which covers approximately 580,000 square miles and includes essentially all of Alberta and portions of British Columbia, Saskatchewan, and Manitoba. Additional potential natural gas supplies may be found in the Arctic and East Coast offshore basins,[9] as evidenced by development activities in progress off the coast of Nova Scotia.[10] The primary producing Provinces of Canadian natural gas are Alberta, British Columbia, and Saskatchewan, with Alberta accounting for about 85 percent of Canadian production.[11] Canada also imports a small amount of natural gas,

[5] OECD, IEA, *Energy Policies of IEA Countries: Canada 2000 Review*, p. 112.
[6] NEB, *Natural Gas Market Assessment* - *Ten Years after Deregulation*, p. 1.
[7] OECD, IEA, *Energy Policies of IEA Countries: Canada 2000 Review*, p. 112.
[8] NEB, *Canadian Natural Gas Market* - *Dynamics and Pricing*, p. 17.
[9] Canadian Association of Petroleum Producers, "Producing Areas," found at Internet address *http://www.capp.ca/prodcingareas.html*, retrieved Mar. 2, 2001, p. 1.
[10] Alexander's Gas & Oil Connections, "Nova Scotia Could Have Massive Gas Projects," found at Internet address *http://www.gasandoil.com/goc/news/ntm04440.html*, retrieved Jan. 23, 2001, p. 1.
[11] NEB, *Natural Gas Market Assessment* - *Ten Years after Deregulation*, p. 8.

less than 2 percent of its consumption, from the United States via the interconnected pipeline system.

In 1999, there were over 700 companies, ranging from large international corporations to small local operations, active in exploration and production of crude oil and natural gas. Concentration in the gas-producing sector in Canada is low, with no single producer having a dominant role. In 1995, the top 10 producers accounted for about 40 percent of production, which was down from 48 percent in 1986.[12] Total Canadian gas production has increased from 74.9 billion cubic meters in 1986 to 170.3 billion cubic meters in 1999. Potential natural gas reserves in Canada are estimated to be 1.7 trillion cubic meters.[13]

Canada is the world's third-largest producer of natural gas, behind the United States and Russia. In 1997, natural gas accounted for 34.2 percent of the country's primary energy production.[14] Canada is the world's second-largest exporter, behind Russia, with essentially all of its exports going to the United States.[15] Canadian natural gas exports to the United States account for 55 percent of Canadian production.

The producing Provinces collect royalties from natural gas producers. Since 1992, these royalties are based on a reference price such as a corporate average price or average Alberta market price rather than on the wellhead price of natural gas, since gas sales contracts are commonly priced at the point of sale rather than at the wellhead.[16]

Transmission and Distribution

Since Canadian gas production is concentrated in the western Provinces and the principal Canadian markets are in the eastern provinces, long transmission pipelines are required to move the gas from domestic producers to domestic consumers (figure 6-1). There are nine major Canadian transmission pipeline systems, all but one of which are owned and operated by private companies. All interprovincial pipelines are privately owned. Several of the pipelines are export oriented and supply gas to the United States through interconnections along the U.S.-Canadian border.[17] Unlike the highly competitive producing sector, the transmission sector of the natural gas industry still requires regulatory oversight.[18]

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[12] Ibid., p. 5.

[13] U.S. Department of Energy (USDOE), Energy Information Administration (EIA), *Canada*, found at internet address *http://www.eia.doe.gov/emeu/cabs/canafull.html,* retrieved May 15, 2001, p. 4.

[14] USDOE, EIA, *Canada*, found at internet address *http://www.eia.doe.gov/emeu/cabs/canafull.html,* retrieved Mar. 1, 2001, p. 2.

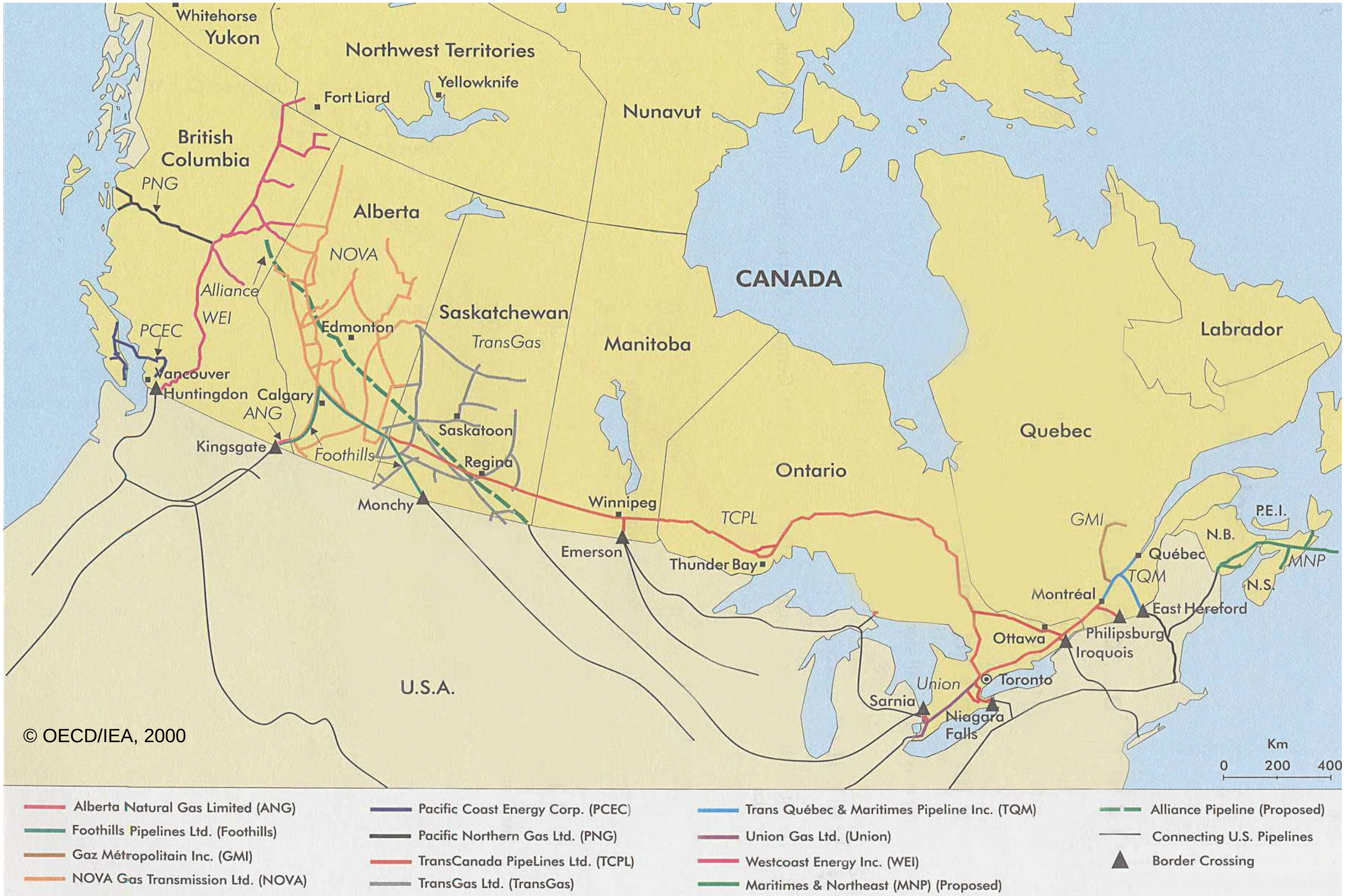
[15] Ibid., p. 5.

[16] NEB, *Natural Gas Market Assessment - Ten Years after Deregulation*, 1996, p. 11.

[17] OECD, IEA, *Energy Policies of IEA Countries: Canada 2000 Review*, p. 107.

[18] NEB, *Natural Gas Market Assessment - Ten Years after Deregulation*, 1996, p. viii.

Figure 6-1
Natural gas pipelines in Canada



Source: Used with permission from the Organization for Economic Cooperation and Development, International Energy Agency. Maps obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition*.

Canadian natural gas pipelines have expanded considerably since regulatory reform to accommodate the growth in sales, particularly exports.[19] However, it has proven to be difficult to match pipeline expansion with demand growth. In 1996, the NEB cited inadequate pipeline capacity between the producing areas in the west and the consuming centers in the east as a primary reason for large price differentials between the two markets.[20] With the addition of pipeline systems that have come on line within the past 2 years, excess capacity reportedly now exists in the Canadian pipeline network, although there may be some minor capacity constraints within individual provincial markets.

The transmission sector appears to be open to new entrants who have the options to build, operate, and/or acquire pipelines or pipeline systems. Direct competition along the same routes appears to be permissible. Siting and bonding may be the only requirements established by regulators.[21] Construction of additional pipeline capacity is being considered. For example, a consortium of producers, pipeline operators, and Canadian Indian tribes reportedly plans to build one, and possibly, two pipelines to carry gas from untapped reserves along the Arctic Ocean. The two pipelines would take 7 years to construct and have an estimated cost of $10 billion.[22]

Since natural gas storage is a substitute for wellhead-to-market delivery capacity, storage is an integral part of an end user's gas supply portfolio. Changes in gas contracting practices and market structure following regulatory reform enhanced the value of storage services. Storage can now be used to arbitrage, or mitigate, seasonal or daily variations in prices. Daily balancing requirements contained in shipping contracts also increased the demand for storage, particularly short-term storage. Increased storage tends to lower both peak and average annual prices, since it results in an increase in peak and annual gas supply, in addition to lowering market price volatility.[23]

As a result of these factors, storage capacity has increased significantly. Previously the domain of local distribution companies (LDCs), regulatory reform has encouraged some pipeline companies to develop storage capacity and to offer additional services such as parking, swaps, transportation exchanges, and gas loans that also serve to reduce transportation costs for gas customers.[24]

Natural gas is distributed to more than 4 million customers (4.2 million residential, 47,000 commercial, and 18,000 industrial) in Canada by Provincially regulated LDCs (table 6-1). The LDCs are monopoly utilities in their service areas, and all except two

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[19] Ibid., p. vii.

[20] Ibid., p. ix.

[21] Industry official, telephone interview by USITC staff, Washington, DC, May 18, 2001.

[22] Alexander's Gas & Oil Connections, "Proposed Pipelines to Carry Arctic Gas," found at Internet address *http://www.gasandoil.com/goc/news/ntm04440.html*, retrieved Jan. 23, 2001, p. 1.

[23] Natural Resources Canada, Natural Gas Division, *Natural Gas Storage: A Canadian Perspective*, p. 2.

[24] NEB, *Canadian Natural Gas Market - Dynamics and Pricing*, Ottawa, Canada, Nov. 2000, p. 15; and Natural Resources Canada, Natural Gas Division, *Natural Gas Storage: A Canadian Perspective*, p. 13.

are locally owned. The eight largest LDCs account for about 95 percent of total LDC sales. The largest LDC, Enbridge Consumers Gas, services nearly one-third of all Canadian customers.[25]

The two largest markets in 1999 were Ontario, with 37.2 percent of national consumption and Alberta (30.9 percent), followed by British Columbia (11.8 percent), Quebec (9.6 percent), Saskatchewan (7.4 percent), and Manitoba (3.1 percent). The markets in New Brunswick and Nova Scotia are just developing, and the other Provinces do not currently have access to natural gas. The LDCs in New Brunswick and Nova Scotia will operate as distributors only, which means that customers will need to purchase gas from a separate marketer.

In most Provinces, many of the industrial consumers purchase gas directly from producers or marketers. For example, in British Columbia, about 85 percent of industrial customers purchase gas through marketers,[26] while in Quebec, virtually all industrial users buy gas directly from producers.[27] In contrast, it appears that few residential and commercial users buy from someone other than their LDC. Thus, marketers have only a small share of the retail market.

In cases where consumers buy gas directly, the LDCs are required to offer various service options, including a transportation service arrangement, termed T-Service, a buy/sell mechanism, and an agency billing and collection transportation service, or ABC-T service. Under a T-Service, an agent/broker/marketer (ABM) purchases gas from a producer or marketer and then arranges for transportation of the gas to its customers, paying the LDC only for the distribution service. Under a buy/sell arrangement, the consumer buys gas from a supplier and then sells the gas to the LDC at the buy/sell reference price (the LDC's weighted average cost of gas (WACOG) less any transportation costs). The LDC then transports the gas to the consumer. Under an ABC-T Service, the ABM sells gas to its customers and the LDC delivers the gas and provides billing and collection services for a fee. Unlike the LDCs, the prices charged by ABMs are not regulated.[28]

Markets and Pricing

Canada's gas market reforms essentially removed regulatory control over prices for the natural gas commodity while preserving control over prices for transmission and distribution services. Prior to reform, most gas was sold by merchant pipelines to LDCs under long-term contracts. Since reform, gas is now sold by producers, aggregators, and a variety of marketing companies and brokers at unregulated prices to LDCs, as well as directly to eligible industrial, commercial, and residential

[25] OECD, IEA, *Energy Policies of IEA Countries: Canada 2000 Review*, p. 109.
[26] NEB, *Canadian Natural Gas Market* **-** *Dynamics and Pricing*, p. 20.
[27] Ibid., p. 45.
[28] Ibid., p. 17.

Table 6-1
Canada's major local distribution companies

Province	Local distribution company	Owner	Provincial sales, 1999
			Billion cubic meters
Alberta	ATCO Gas (North and South)	Private	20.1
	AltaGas Utilities Inc.	Private	
British Columbia	BC Gas Utility Ltd.	Private	7.7
	Pacific Northern Gas Ltd	Private	
	Centra Gas British Columbia	Private	
Manitoba	Centra Gas Manitoba Incorporated	Public (Crown Corp.)	2.0
New Brunswick	Enbridge Gas New Brunswick	Private	([1])
Newfoundland	No LDC. Natural gas service being considered.		([1])
Nova Scotia	Sempra Atlantic Gas Inc.	Private	([1])
Ontario	Union Gas Limited	Private	24.1
	Enbridge Consumers Gas	Private	
Prince Edward Island	No LDC. Natural gas service being considered.		([1])
Quebec	Gaz Metropolitan and Company	Private	6.2
	Gazifere	Private	
Saskatchewan	SaskEnergy	Public (Crown Corp.)	4.8
Yukon/Northwest Terr.	No LDC.		([1])

[1] Not available.

Source: Compiled by the Commission.

consumers.[29] The regulatory bodies in each Province establish the options available to the various classes of customer.[30] Industrial and large commercial consumers generally choose their own marketer. Small commercial and residential gas users may also purchase gas directly, but many have yet to exercise their option. The LDCs continue to transport gas to all consumers within their service region, but they are only permitted to sell gas to customers who have elected not to switch to a competing marketer. LDCs may earn profits only on transportation service revenues, as they are not allowed to make a profit on the commodity price of gas.[31]

In response to the competitive market reforms, the volume of transactions between producers, marketers, and consumers has increased substantially. In general, market

[29] NEB, *Natural Gas Market Assessment - Ten Years after Deregulation*, p. viii.
[30] Ibid., p. ix.
[31] NEB, *Canadian Natural Gas Market - Dynamics and Pricing*, p. 17.

participants follow a portfolio approach, entering into a mixture of long-, medium-, and short-term contracts, then turning to a spot market for last minute refinements.[32] Active spot markets[33] have developed at various locations, some of which are known as hubs, across North America. The main pricing point for Alberta natural gas is the AECO-C/NIT hub, which carries about 12 billion cubic feet per day (bcf/d), with other Canadian hubs at Sumas/Huntingdon (1.6 bcf/d), British Columbia, and Dawn, Ontario (3 bcf/d).[34] Electronic gas trading systems have subsequently evolved to provide market information and execute transactions of various durations on behalf of buyers and sellers. The three main trading systems operating in Alberta are Natural Gas Exchange (NGX), Enron-Online, and Altrade.[35]

Over time, the average duration of contracts has declined. Although large volumes of Canadian gas are still sold under long-term contracts, the pricing in many of these contracts is tied in whole or in part to spot price indices which fluctuate either monthly or daily.[36] These developments have reportedly increased price transparency and enhanced the efficiency of the natural gas market.[37]

In addition to the long-term contract and spot markets, a financial market has evolved as well. Since a futures contract for gas was first listed on the New York Mercantile Exchange (NYMEX) in 1990, such contracts have become an important benchmark for gas pricing across North America.[38] The delivery point for NYMEX futures contracts is the Henry Hub, which is in Louisiana. Currently there are natural gas futures contracts available on the NYMEX and on the Chicago Board of Trade. While these contracts involve delivery of gas only in the United States, Canadian firms are quite active participants. Since Canadian producers and marketers have both U.S. and Canadian customers, there is a tendency for prices to converge. Indications of the integration of the North American market include the fact that Alberta Hub prices track Henry Hub prices, and the convergence of prices paid by Canadian and U.S. buyers for Alberta gas.[39] Other financial tools available to market participants include over-the-counter instruments such as collars and swaps.[40]

As noted previously, pricing for the gas commodity has been separated from pricing for the transportation service. As a consequence, marketers must arrange for the physical transportation of the gas to their customers through transmission and distribution pipelines by scheduling capacity in advance. Marketers can subsequently resell this reserved capacity through a secondary capacity-release market. Prices for transmission and distribution are based on the cost of services and continue to be regulated using the rate of return methodology. However, in the mid-1990s, the NEB issued guidelines to permit the negotiation of transmission rates in some cases instead

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[32] NEB, *Natural Gas Market Assessment - Ten Years after Deregulation*, p. ix.

[33] The spot market includes all transactions for sales of 30 days or less, but typically refers to a 30-day sale.

[34] NEB, *Canadian Natural Gas Market - Dynamics and Pricing*, p. 12.

[35] Ibid.

[36] Ibid.

[37] NEB, *Natural Gas Market Assessment - Ten Years after Deregulation*, p. viii.

[38] NEB, *Canadian Natural Gas Market - Dynamics and Pricing*, p. 13.

[39] Ibid., p. 14.

[40] Ibid., p. 16.

of always requiring traditional cost-of-service regulation. Prices for transmission services have remained relatively constant since regulatory reform.[41] Another result of regulatory reform has been the introduction of new services incidental to transmission and distribution, including back-haul service, delivery-point flexibility, and bid-rates for various services.

The effect of regulatory reform, in both the United States and Canada, on the integration of the two markets into a North American market is fairly clear. This integration, accompanied by the tracking of prices in major producing areas and the effective operation of a futures market, implies price transparency and the absence of major transmission barriers.[42] The effect on natural gas prices, and on prices of the incorporated services, transmission, storage, and distribution, within the Canadian market is less clear. Gas prices reportedly decreased following regulatory reform in the mid-1980s until about 1995, after which they rose in most Provinces through late 2000. Since the start of 2001, gas prices have fallen.

Although production of natural gas in Canada has increased by about 60 percent since regulatory reform, the share of the total Canadian energy market held by gas has increased only slightly since deregulation. As would be expected, gas consumption after regulatory reform rose faster in the industrial sector than in the commercial and residential sectors. A steep decline in well-head prices in western producing areas resulted in significantly lower delivered gas prices to industrial consumers. However, prices fell only slightly for commercial and residential customers, and those in the eastern markets experienced even smaller savings due to the larger proportion of distribution and storage costs in the total cost of supply.[43]

Impediments to Competitive Market Development

As noted at the start of this chapter, Canada has an open natural gas market. There do not appear to be any significant barriers that would prevent major gas buyers from accessing competitively priced supplies. Similarly there do not appear to be any barriers to prevent natural gas producers from receiving competitive prices for their gas and related services. The principal impediment to market development may be the difficulty of marketing to small consumers, as evidenced by the paucity of new marketing participants. This may be a function of the recent volatility of the market and the difficulty of a marketer reaching a critical size to be able to offer prices that are more competitive than those of the incumbent LDCs.

Canada maintains few measures that could be considered to be limitations on the presence or activities of foreign firms. In general, foreign firms appear to enjoy full market access and national treatment. However, Canada does have a formal investment review process. U.S. firms are not exempt from that process, although the

[41] NEB, *Natural Gas Market Assessment - Ten Years after Deregulation*, p. vii.
[42] NEB, *Canadian Natural Gas Market - Dynamics and Pricing*, p. 13.
[43] NEB, *Natural Gas Market Assessment - Ten Years after Deregulation*, p. ix.

NAFTA does provide a higher review threshold for U.S. investments.[44] Nevertheless, foreign companies, particularly U.S. firms, seem to participate in all activities in Canada, just as Canadian firms actively participate in the U.S. market.

[44] U.S. Department of Commerce, *FY 2001 Country Commercial Guide: Canada*, June 2000, found at *http://www.stat-usa.gov*, retrieved May 16, 2001.

CHAPTER 7
JAPAN

Overview

Japan's gas market is divided into three categories of suppliers: general gas suppliers, community gas suppliers, and liquefied petroleum gas (LPG) dealers. General gas supply is dominated by four privately-owned, regional gas monopolies–Osaka Gas, Saibu Gas, Toho Gas, and Tokyo Gas[1]–but also includes more than 240 city gas companies, each with its own franchised service area.[2] General gas companies supply nearly 27 million retail gas customers in Japan, or more than one-half of the total gas market.[3] Each of the regional gas monopolies owns a pipeline network, composed of high-pressure and medium-pressure transmission lines, that serves retail customers in the geographic area within which the utility is located. These pipelines also connect to the distribution lines of smaller gas companies for the purposes of wholesale supply.[4] There is no interconnection among the pipeline networks of the four major gas utilities. General gas suppliers use imported liquefied natural gas (LNG) as a primary source of natural gas. The regional gas monopolies are vertically integrated with respect to LNG import, tanker transport, storage, regasification, transmission, and supply. Therefore, they participate in all aspects of the market, with the exception of natural gas production.[5]Community gas supply is comprised of nearly 1,700 private sector companies. These companies are connected to their customers by pipelines, but they use propane rather than natural gas as a fuel source. Each community supplier serves no less than 70 retail gas customers. In total, nearly 2 million customers in Japan

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[1] Osaka, Toho, and Tokyo Gas serve nearly 65 percent of gas customers in Japan, and account for more than 75 percent of total gas sales. Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA), *Natural Gas Distribution: Focus on Western Europe*, (Paris, France: OECD, 1998), p. 280.

[2] Nearly 35 percent of the small general suppliers are publicly owned, and the remainder are private-sector companies. Industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[3] Natural gas supplied by general gas suppliers consists of roughly 80 percent liquefied natural gas (LNG) and 20 percent liquefied petroleum gas (LPG). The two fuels are mixed at the LNG terminals of the regional gas monopolies, and then transported by pipeline to the monopolies' retail customers or to smaller city gas companies. Industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[4] Industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[5] Two small general suppliers, Sendai City Gas (a municipally-owned company) and Shizuoka Gas (a privately-owned company), also import natural gas (in the form of LNG). OECD, IEA, *Natural Gas Transportation: Organization and Regulation*, (Paris, France: OECD, 1994), pp. 232-233; and *Annual Report 2000*, Osaka Gas Co., Ltd., pp. 14-25; *Annual Report 1999*, Tokyo Gas Co., Ltd., p. 22; industry representative, telephone interview by USITC staff, Mar. 16, 2001; and industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

receive gas through community supply. Community gas suppliers, like general gas suppliers, are regulated by Japan's Gas Utility Law.[6]

The third category of gas supplier in Japan is the liquefied petroleum gas (LPG) dealer. There are approximately 30,000 small LPG dealers that serve 25 million customers in Japan. LPG dealers do not own pipeline distribution networks, and they transport LPG in canisters by truck to their customers.[7] Japan's Gas Utility Law does not address this segment of the gas market. However, Japan's Ministry of Economy, Trade, and Industry (METI),[8] which is responsible for regulating the natural gas market, has required that LPG dealers make their costs transparent to their customers.[9]

Japan has initiated reform of its gas sector through two amendments to the Gas Utility Law.[10] As noted, these amendments apply to general and community gas suppliers, but not to LPG dealers. The first amendment, implemented in March 1995, opened retail competition for large-scale customers with annual gas demand of 2 million cubic meters or higher. These customers were permitted to choose their own supplier from among regional gas monopolies, city gas companies, and new entrants, and to negotiate gas rates on a bilateral basis directly with suppliers.[11]

In 1999, Japan passed a second amendment to the Gas Utility Law, which permits retail choice for customers with annual demand of at least 1 million cubic meters. In addition, the amendment enhances wholesale competition by allowing Japan's four regional gas monopolies, and other wholesale suppliers, to sell gas to city gas companies outside their service areas without prior permission from the Ministry of Economy, Trade, and Industry (METI). The prices and terms of wholesale supply are determined through bilateral contracts between gas wholesalers and city gas

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[6] The Gas Utility Law was established in 1954. OECD, IEA, *Natural Gas Transportation: Organisation and Regulation*, p. 235; and The Gas Utility Law of Japan, Tokyo Gas Co., Ltd., pp. 2-3.

[7] U.S. Department of State telegram, "Russian Gas For Tokyo? GOJ Reportedly Plans to Build Pipeline from Sakhalin," message reference No. 007449, prepared by U.S. Embassy, Tokyo, Oct. 13, 2000; and industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[8] On January 6, 2001, the Ministry of International Trade and Industry (MITI) changed its name to the Ministry of Economy, Trade, and Industry (METI). Information provided by Officials of the Government of Japan through electronic correspondence, July 11, 2001; and Ministry of Economy, Trade, and Industry (METI), *Energy in Japan (Overview)*, found at *http://www.meti.go.jp/english/aboutmeti/data/a23201e.html*, retrieved Feb. 13, 2001.

[9] Industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[10] The Gas Utility Law was established in 1954. OECD, IEA, *Natural Gas Transportation: Organisation and Regulation*, p. 235.

[11] Summary report on 1999 amendment to Gas Utility Law, prepared by the Institute of Energy Economics in Japan, and provided to USITC staff by industry representative through faxed correspondence, Feb. 13, 2001.

companies.[12] The 1999 amendment also introduces third-party access to the transmission pipelines of the four regional gas utilities, which are instructed to publish the terms, conditions, and transportation rates pertaining to third-party access in accordance with guidelines established by METI.[13] Finally, the amendment permits both general and community gas suppliers to reduce retail gas rates without prior approval from METI,[14] and to offer different rate packages to customers with different usage characteristics.[15]

In sum, the 1995 amendment to the Gas Utility Law:

- Permitted retail customers with annual demand of 2 million cubic meters or more to choose their supplier;
- Allowed general gas suppliers to supply contestable customers outside their franchised service areas; and
- Deregulated gas prices for newly-contestable customers by allowing them to negotiate rates directly with suppliers.

Subsequently, the 1999 amendment:

- Lowered the threshold for contestable customers to those with annual demand of at least 1 million cubic meters;
- Permitted city gas companies to choose entities apart from the regional gas monopolies for wholesale supply without prior permission from METI;
- Introduced third-party access to gas utilities' transmission and distribution pipelines; and
- Further deregulated gas prices by allowing general and community suppliers to offer competitive rates without prior approval from METI.

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[12] Under the 1999 amendment, companies that wish to supply natural gas on a wholesale basis by pipeline may do so without prior permission from METI, unless they are supplying smaller gas utilities with capitalization of below 500 million ¥. Information provided by Officials of the Government of Japan through electronic correspondence, July 11, 2001

[13] In particular, the utilities are to provide written information to METI that makes explicit which pipelines are available for third-party access (TPA); the volume of gas that the utilities are prepared to receive through TPA; the terms, conditions, and tariffs pertaining to TPA; and safety and security rules. Summary report on 1999 amendment to Gas Utility Law, prepared by the Institute of Energy Economics in Japan, and provided to USITC staff by industry representative through faxed correspondence, Feb. 13, 2001.

[14] General gas suppliers must receive approval from METI before raising retail gas rates. Summary report on 1999 amendment to Gas Utility Law, prepared by the Institute of Energy Economics in Japan, and provided to USITC staff by industry representative through faxed correspondence, Feb. 13, 2001.

[15] Summary report on 1999 amendment to Gas Utility Law, prepared by the Institute of Energy Economics in Japan, and provided to USITC staff by industry representative through faxed correspondence, Feb. 13, 2001.

In January 2001, a study group was established to assess the progress of reform in the natural gas sector.[16] The study group is scheduled to present its findings to METI in March 2002 and, based on these findings, METI will decide whether or not to pursue further reform of the gas market beginning in 2003.[17]

Industry Structure

Production and Imports

Japan imports nearly 96 percent of the natural gas it consumes, with the remaining 4 percent supplied through indigenous production.[18] In 1999, Japan imported more than 72 billion cubic meters of LNG, primarily from Australia, Brunei, Indonesia, Malaysia, Qatar, and the United Arab Emirates.[19] Because Japan's natural gas pipelines share no interconnection with pipelines in other countries, all of Japan's natural gas imports are in the form of liquefied natural gas (LNG). Among Japanese entities that import LNG are the four regional gas monopolies, electric power companies, steel companies, and two of the 240 city gas companies.[20] These entities own and operate LNG terminals[21] throughout Japan (table 7-1) and, in some cases,

[16] The study group comprises representatives from the electric utility industry, the gas utility industry, the housewives' association, and academia. Industry representatives, interviews by USITC staff, Tokyo, Japan, May 7, 2001.

[17] Proceedings of the study group are made available to the public and posted on METI's website (in Japanese). Officials of the Government of Japan and industry representatives, interviews by USITC staff, Tokyo, Japan, May 7-9, 2001.

[18] Japan reportedly purchases 60 percent of the global supply of LNG. OECD, IEA, *IEA Statistics: Natural Gas Information*, (Paris, France: OECD, 2000), p. IV. 219; and industry representatives, interview by USITC staff, Tokyo, Japan, May 7. 2001.

[19] Natural gas supplies 13 percent of Japan's energy needs. OECD, IEA, *IEA Statistics: Natural Gas Information*, p. IV. 218; and U.S. Department of Energy (USDOE), Energy Information Administration (EIA), Country Analysis Briefs, *Japan*, Apr. 2001, found at *http://www.eia.doe.gov/emeu/cabs/japan.html*, retrieved Aug. 15, 2001.

[20] Japanese entities that import LNG have traditionally established long-term contracts with supplying countries. These contracts allow Japanese importers to take possession of the LNG once it arrives in Japan (ex-ship) or, alternatively, once it leaves the port of the exporting country (free-on-board). In some cases, Japanese trading companies act as intermediaries. OECD, IEA, *Natural Gas Transportation: Organization and Regulation*, pp. 232-233; and OECD, IEA, *Energy Policies of IEA Countries: Japan 1999 Review*, found at Internet address *http://www.iea.org/pubs/reviews/files/japan99/08-jap.htm*, retrieved Feb. 1, 2000.

[21] Liquefied natural gas (LNG) is transferred from tankers to terminals, where it is stored. LNG is then converted to vapor form in nearby regasification plants and transported by pipeline directly to large industrial and commercial users, or to city gas companies. OECD, IEA, *Natural Gas Transportation: Organization and Regulation*, p. 39.

Table 7-1
Ownership of LNG terminals in Japan

LNG Terminal	Ownership
Sendai	Sendai City Gas
Higashi-Niigata	Nihonkai LNG[1]
Sodegaura	Tokyo Electric Tokyo Gas
Higashi-Ogishima	Tokyo Electric
Futtsu	Tokyo Electric
Negishi	Tokyo Electric Tokyo Gas
Shimizu	Shizuoka Gas
Ogishima	Tokyo Gas
Chita Joint	Chubu Electric Toho Gas
Chita	Chita LNG[2]
Kawagoe	Chubu Electric Toho Gas
Himeji	Kansai Electric Osaka Gas
Midorihama[3]	Toho Gas
Senboku I and II	Osaka Gas
Tsuruga[3]	Osaka Gas
Yokkaichi	Toho Gas
Yokkaichi LNG Center	Chubu Electric
Hiroshima	Hiroshima Gas
Pita	Oita LNG[4]
Wakayama[3]	Kansai Electric
Kagoshima	Nihon Gas
Fukuoka	Saibu Gas
Tobata[5]	Kitakyushu LNG[5]
Yanai	Chugoku Electric

[1] Shareholders in Nihonkai LNG include Tohoku Electric, Hokkaido Tohoku Development Bank, Niigata Prefecture Oil Resources Development Company, and Teikoku Oil.
[2] Shareholders in Chita LNG are Chubu Electric and Toho Gas.
[3] Currently planned or under construction.
[4] Shareholders in Oita LNG are Kyushu Electric, Kyushu Oil, and Oita Gas.
[5] Shareholders in Kitakyushu LNG include Kyushu Electric and Nippon Steel.

Source: Adapted from Asia Pacific Energy Research Centre, “Natural Gas Infrastructure Development,” Mar. 2000, p. 28; and Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA), *Natural Gas Transportation: Organisation and Regulation*, (Paris, France: OECD, 1994), p. 234.

oceangoing LNG tankers as well.[22] Domestic production of natural gas occurs primarily in the northern provinces of Japan, and this production is carried out by two Japanese companies, the Japan Petroleum Exploration Company (JAPEX) and Teikoku Oil.[23]

There are reportedly no legal restrictions on the importation of LNG into Japan, nor on the domestic production of natural gas. Firms that produce gas domestically must have a subsidiary presence in Japan and be licensed by the government under Japan's Mining Law. ExxonMobil, through a joint venture with Japanese petroleum firm, Teikoku Oil, currently produces gas in Japan's Iwaki Oil Field, located near Fukushima Prefecture. Other non-Japanese petroleum firms, including Amoco, Unocal, and Royal Dutch Shell, are now or have previously been involved in natural gas production in Japan.[24]

Transmission and Distribution

Each of the four privately owned gas monopolies in Japan—Osaka Gas, Saibu Gas, Toho Gas, and Tokyo Gas[25]—owns a transmission pipeline that serves the geographic area where the utility is located (figure 7-1). In addition, each pipeline is located near two or more LNG reception terminals which are owned primarily by the gas and electric utilities,[26] in some cases through joint venture companies (see table 7-1). There are 24 LNG reception terminals in Japan,[27] and another 26 'satellite' terminals. LNG is transported by truck from reception terminals to satellite terminals, at which point it is regasified and transported to retail customers through local distribution lines.[28]

Although 1995 and 1999 reforms to Japan's Gas Utility Law permitted third-party access to the transmission pipelines of the four regional gas utilities, the reforms did

[22] Osaka Gas International, a subsidiary of Osaka Gas, operates tankers that are dedicated to the transport of LNG. With reform of the natural gas market, Osaka Gas has considered leasing its tankers to third-parties that transport imported LNG to Japan. Tokyo Gas also has a subsidiary that operates a proprietary LNG tanker service. OECD, IEA, *Natural Gas Transportation: Organisation and Regulation*, p. 234; and Osaka Gas Co., Ltd., *Annual Report 2000,* pp. 23 and 25; and industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[23] The Japan Petroleum Exploration Company operates its largest gas production site in Niigata Prefecture, located in the northwestern part of Japan's main island, Honshu. Teikoku Oil also produces gas in Niigata Prefecture. Other Japanese entities, such as the Kanto Tennen Gas Development Company, produce natural gas through smaller gas fields located in Japan. Industry representatives, interviews by USITC staff, Tokyo, Japan, May 9, 2001.

[24] Industry representatives, interviews by USITC staff, Tokyo, Japan, May 8-9, 2001.

[25] Asia Pacific Energy Research Centre, "Natural Gas Pipeline Development in Northeast Asia," Apr. 2000, p. 25.

[26] The electric utilities connect directly to LNG terminals through proprietary pipelines that they build and operate at their own expense. Industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[27] These include LNG terminals that are currently planned or under construction.

[28] OECD, IEA, *Energy Policies of IEA Countries: Japan 1999 Review*; and Asia Pacific Energy Research Centre, "Natural Gas Pipeline Development in Northeast Asia," p. 34.

Figure 7-1
Natural gas pipelines in Japan

Source: Used with permission from the Organization for Economic Cooperation and Development, International Energy Agency. Maps obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition.*

not provide access to the distribution pipelines of smaller general gas suppliers, nor to the pipelines of Japan's two largest domestic gas producers, the Japan Petroleum Exploration Company and Teikoku Oil. Moreover, amendments to the Gas Utility Law do not mandate access to LNG terminals or storage facilities owned by the electric and gas utilities.[29]

Under 1999 reforms, the four regional gas utilities are required to publish the terms, conditions, and tariffs pertaining to third-party access to their transmission pipelines in accordance with METI guidelines.[30] METI has asked the utilities to separate out costs that pertain to wheeling under the activity-based cost (ABC) accounting system.[31] Wheeling tariffs are likely to be calculated using a 'forward-looking cost methodology', which will require the utilities to incorporate anticipated efficiency gains in transmission prices.[32]

The 1999 reform to the Gas Utility Law includes provisions on the use of publicly- and privately-held land to construct pipelines for the supply of natural gas. Entities that wish to construct new pipelines must receive permission from METI.[33] The law does not address the issue of building competing pipelines, nor does it provide METI with regulatory authority over pipelines that may be built between Japan and foreign countries.[34] In May 1999, U.S. oil company ExxonMobil, through its subsidiary Exxon Japan Pipeline, Ltd., announced plans to study the feasibility of constructing

[29] Officials of the Government of Japan and industry representatives, interviews by USITC staff, Tokyo, Japan, May 7-9, 2001

[30] As of this writing, Osaka Gas, Toho Gas, and Tokyo Gas have filed "model" third-party transmission service agreements with METI, and Saibu Gas is expected to do so in the near future. Officials of the Government of Japan, interview with USITC staff, Tokyo, Japan, May 9, 2001.

[31] Under the activity-based cost (ABC) accounting system, METI requires that the four regional gas utilities separate out costs that apply to wheeling, or third-party transmission, from other operational costs. Third-party transmission costs are primarily those associated with pipeline operation, safety, and maintenance. Each of these costs is reviewed separately by METI, and then grouped together under one wheeling charge that is passed on to third parties. Industry representatives, interview by USITC staff, Tokyo, Japan, May 7, 2001.

[32] U.S. Department of State telegram, "'Japan's Lost Decade'–Third and Final Report of Regulatory Reform Committee," message reference No. 09331, prepared by U.S. Embassy, Tokyo, Dec. 22, 2000; and industry representative, interview by USITC staff, Tokyo, Japan, May 7, 2001.

[33] METI, *The Gas Utility Law of Japan*, 1999 revised version, pp. 51-52.

[34] Various laws apply to pipeline construction, depending on the ultimate purpose of the pipeline to be built. For example, if a pipeline is constructed to provide gas for electricity generation, then its operation is regulated under the Electric Utility Industry Law; for nongeneration gas supply, under the Gas Utility Law; for transmission only, under the High Pressure Transmission Law; and for gas production, under the Mining Law. U.S. Department of State telegram, "Deregulation Spurs U.S. Firms' Interest in Japan's Energy Market and Sakhalin Gas Pipeline," message reference No. 007970, prepared by U.S. Embassy, Tokyo, Sept. 27, 1999; and officials of the Government of Japan, interview by USITC staff, Tokyo, Japan, May 9, 2001.

a pipeline from the Russian island of Sakhalin to Japan.[35] During the same year, U.S. petroleum firm Texaco outlined plans to construct a pipeline from Sakhalin to Hokkaido, Japan's northernmost island.[36] In addition, Japanese firm Teikoku Oil, which is involved in domestic natural gas production, is constructing a new transmission pipeline from northwestern Japan to Gunma Prefecture. The pipeline will be used to supply natural gas on a wholesale and retail basis.[37]

Gas distribution is performed by general (both regional gas monopolies and city gas companies) and community gas suppliers.[38] Each gas supplier provides gas to customers within a franchised service area through its own distribution lines.[39] General gas suppliers distribute natural gas using imported LNG, domestically produced natural gas, or a combination thereof, while community gas suppliers use imported liquefied petroleum gas (LPG) as a primary feedstock.[40] General and community gas suppliers serve nearly 30 million customers in Japan, and nearly one-fifth of the country's urban areas is connected to pipeline distribution networks.[41]

Markets and Pricing

Japan's regulatory reforms are intended to introduce competition in the marketing of natural gas to large industrial customers and to regional or local distribution companies. These eligible customers may now choose to enter into bilateral contacts at negotiated prices with any existing distribution company or one of several new entrants. To date, two general gas suppliers, Satte Gas and Tokyo Gas, have entered

[35] The pipeline would be built by a consortium comprised of Japanese trading firms Itochu and Marubeni, the Japan Sakhalin Pipeline FS Co., a subsidiary of the Japan Petroleum Exploration Company, and ExxonMobil. Reportedly, consortium members will determine whether or not to construct the pipeline in the next 2 to 3 years. Industry representatives, interviews by USITC staff, Tokyo, Japan, May 9, 2001.

[36] Development of this project has been placed on hold pending the merger of Chevron and Texaco. Industry representative, interview by USITC staff, Tokyo, Japan, May 8, 2001.

[37] Industry representatives, interview by USITC staff, Tokyo, Japan, May 9, 2001.

[38] In 1997, consumption of gas supplied by general gas suppliers was as follows: residential customers (41 percent); commercial customers (23 percent); and industrial customers (36 percent). By 2010, these proportions are forecasted to change, so that residential, commercial, and industrial customers will account for 33 percent, 28 percent, and 39 percent of total gas consumption, respectively. Asia Pacific Energy Research Centre, "Natural Gas Pipeline Development in Northeast Asia," p. 33.

[39] OECD, IEA, *Natural Gas Distribution: Focus on Western Europe*, p. 280; and Asia Pacific Energy Research Centre, "Natural Gas Pipeline Development in Northeast Asia," p. 27.

[40] Asia Pacific Energy Research Centre, "Natural Gas Infrastructure Development," Mar. 2000, p. 28; and industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

[41] Japan's pipeline network is 3,300 kilometers (km) in length, compared to more than 400,000 km in the United States. OECD, IEA, *Energy Policies of IEA Countries: Japan 1999 Review*; and industry representatives, interview by USITC staff, Washington, DC, Apr. 12, 2001.

into supply contracts with large-volume customers outside their service areas,[42] and six Japanese companies—the Air & Water Company, the Japan Petroleum Exploration Company, the Kansai Electric Power Company, Nippon Steel, Teikoku Oil, and Tohoku Natural Gas—have applied as new entrants to the large-volume retail segment.[43] In order to receive a marketing license, each new entrant must have access to a source of LNG or pipeline gas. Teikoku Oil and the Japan Petroleum Exploration Company produce gas domestically, and have their own transmission pipelines. Tohoku Natural Gas[44] and Nippon Steel import LNG and operate LNG terminals through joint ventures with Tohoku Electric Company and Kyushu Electric Company, respectively. The Kansai Electric Power Company operates its own LNG terminal.[45] Other Japanese companies that plan to enter the large-volume retail gas market are NipponMitsubishi Oil, which recently formed a joint venture with Teikoku Oil, and will use the latter's pipelines for retail supply;[46] and oil firm Idemitsu Kosan, which plans to form a joint venture with Chugoku Electric, a large power company in western Japan that owns an LNG terminal.[47] Although competition in wholesale and large-volume retail supply is theoretically possible throughout the country, lack of a national trunkline currently precludes the development of a nationwide gas market. As a result, competition for wholesale and retail customers occurs primarily at the regional level, with the largest markets located near Tokyo and Osaka. As of 2001, 13 retail customers receive gas from providers other than the monopoly gas supplier.[48] Noncontestable customers, those with annual demand of below one million cubic meters, continue to be served by a regional monopoly. Prices are regulated under a cost-plus mechanism, which takes into account the cost of capital and a pre-determined rate of return.[49] General gas

[42] METI, "Energy in Japan," found at Internet address *http://www.meti.go.jp*, retrieved Feb. 13, 2001.

[43] Officials of the Government of Japan, interview by USITC staff, Tokyo, Japan, May 9, 2001.

[44] Tohoku Natural Gas is owned jointly by the Japan Petroleum Exploration Company and the Tohoku Electric Power Company. Officials of the Government of Japan, interview by USITC staff, Tokyo, Japan, May 9, 2001.

[45] OECD, IEA, *Natural Gas Transportation: Organization and Regulation*, p. 234.

[46] Industry representative, interview by USITC staff, Tokyo, Japan, May 9, 2001; and "Nippon Mitsubishi, Teikoku Oil in Pact for Gas JV," *The Economic Times*, Dec. 26, 2000, found at Internet address *http://www.economictimes.com/*, retrieved Apr. 17, 2001.

[47] "Japan Idemitsu Plans Retail Gas Operations, JV with Chugoku Electric," *Dow Jones Newswires*, Apr. 10, 2001, found at *http://www.business.com/*, retrieved Apr. 17, 2001.

[48] These are large-volume customers who have switched usage to natural gas from another fuel. Officials of the Government of Japan, interviews by USITC staff, Tokyo, Japan, May 9, 2001.

[49] In 1997, customers with annual demand of less than 1 million cubic meters accounted for nearly 60 percent of the total number of customers of the three largest gas utilities in Japan: Osaka, Toho, and Toho Gas. Officials of the Government of Japan, interview by USITC staff, Tokyo, Japan, May 9, 2001.

suppliers are also subject to the yardstick mechanism, which is designed to motivate them to operate more efficiently.[50]

For all segments of the market, wholesale and retail gas prices remain bundled with the price of transmission and distribution (table 7-2). However, competitive marketers may negotiate transportation tariffs with any of the four regional gas utilities. These contracts must be filed with METI and made available to the public.[51] The utilities are instructed to calculate transportation rates according to guidelines provided by METI. METI will periodically review such rates to ensure that they reflect true costs.[52]

Impediments to Competitive Market Development

Although amendments to the Gas Utility Law have allowed for limited competition in the wholesale and retail supply segments, full competition in Japan's natural gas market is circumscribed by the following impediments:

- Lack of adequate pipeline infrastructure;
- Difficulties in implementing nondiscriminatory third-party access; and
- The status of existing long-term contracts for LNG.

As noted, the development of Japan's natural gas market is partly constrained by the country's pipeline infrastructure. Pipeline networks in Japan cover only 5 percent of the country's geography, and serve one-half of Japanese households.[53] There exists no nationwide trunkline connecting the pipeline networks of the four dominant gas utilities, so that, with few exceptions, it is not currently feasible to purchase or sell gas across regions via pipeline. At the same time, new pipeline construction is impeded by the high costs of pipeline construction, and the difficulty of securing both construction permits and rights of way. Pipeline construction costs in Japan reportedly reach ¥ 800 million per kilometer, compared to ¥ 73 million for interstate pipelines in the United States, and ¥ 100 million for transmission pipelines in

[50] Under the yardstick mechanism, METI compares gas utilities based on two categories of costs: general and administrative expenses, and investment in capital and facilities. Those utilities that are the most efficient are permitted to establish gas rates that allow them to recoup the full costs of their operations, while less-efficient utilities are required to establish rates that reflect only 99 percent or 98 percent of their full costs. Officials of the Government of Japan, interview by USITC staff, Tokyo, Japan, May 9, 2001.

[51] Officials of the Government of Japan and industry representatives, interviews by USITC staff, Tokyo, Japan, May 7-9, 2001.

[52] Industry representatives, interview by USITC staff, Tokyo, Japan, May 7, 2001.

[53] OECD, IEA, *Energy Policies of IEA Countries: Japan 1999 Review*.

Table 7-2
Regulatory characteristics of wholesale supply, retail supply, and third-party pipeline access in Japan

	Are prices regulated or negotiated?	Are contracts required to be filed with METI?	Must new entrants have prior approval from METI to participate in this segment of the market?	Does METI require that gas companies unbundle supply and transmission prices in their contracts with customers?
Wholesale supply	Negotiated	Yes	No	No
Large-volume supply[1]	Negotiated	Yes	No	No
Noncontestable retail supply[2]	Regulated	Yes	Yes	No
Third-party access to pipelines of 4 regional gas utilities	Regulated	Yes	NA	NA

[1] Customers with annual demand of one million cubic meters or greater.
[2] Customers with annual demand below one million cubic meters.

Source: Compiled by the Commission.

Europe.[54] In addition, firms that wish to build either land lines or undersea pipelines in Japan must secure permits from both local and national agencies including, for example, local fire and police departments, METI, the Ministry of Infrastructure and Construction, the Ministry of Agriculture, and the Maritime Defense Agency. Firms that plan to build pipelines must also make compensatory payments to landowners and local fishermen to secure rights of way.[55] One large Japanese oil company that recently completed construction of a new pipeline reported that 10 different laws relate to pipeline construction in Japan, each of which is applied locally. Construction of this pipeline required 50 different permits and took 5 to 6 years to complete.[56]

With respect to third-party access, a number of difficulties have been identified. The four major gas utilities are required to permit third-party access to their transmission and distribution pipelines. As noted, the utilities are directed by METI to separate out costs that pertain to wheeling under the activity-based cost (ABC) accounting system. METI is currently the only entity that has the authority to issue change orders to the gas utilities if third-party access terms and prices are judged to be unfair or discriminatory.[57] However, industry sources indicate that, in practice, the terms and conditions of third-party access are not fully transparent, and that METI lacks sufficient resources to ensure that transmission rates are calculated fairly.[58]

Another problem with the third-party access regime is that amendments to the Gas Utility Law do not provide for third-party access to the distribution lines of the smaller gas companies, or the transmission lines of two large domestic gas and oil producers, the Japan Petroleum Exploration Company (JAPEX) and Teikoku Oil. Third-party access to the pipelines of JAPEX and Teikoku Oil is not required because these pipelines connect to offshore gas fields, and thus come under the jurisdiction of the Mining Law rather than the Gas Utility Law. Nonetheless, the pipelines are currently used to some extent for wholesale and large-volume retail supply. Although access to the pipelines is not mandated under the Gas Utility Law, some firms have gained third-party access through bilateral negotiations.[59]

Lack of mandatory third-party access to LNG facilities of the gas and electric utilities also presents difficulty for new entrants to Japan’s natural gas market. Because Japan relies almost exclusively on imported LNG, new entrants must either have access to existing LNG facilities or be able to construct their own facilities. Industry representatives indicated that it may be possible for new entrants to negotiate third-party access to LNG facilities on a bilateral basis. However, some industry sources note that there exists little excess capacity in LNG facilities in Japan, so that even if a mandatory third-party access system were to develop, it would likely not have a

[54] Presentation by Shell Gas & Power Japan Ltd. before METI Gas Reform Committee, Mar. 8, 2001.

[55] Industry representatives, interviews by USITC staff, Tokyo, Japan, May 8, 2001.

[56] Industry representatives, interviews by USITC staff, Tokyo, Japan, May 9, 2001.

[57] Officials of the Government of Japan, interview by USITC staff, Tokyo, Japan, May 8, 2001.

[58] Industry representatives, interview by USITC staff, Tokyo, Japan, May 7, 2001.

[59] Industry representatives, interviews by USITC staff, Tokyo, Japan, May 9, 2001.

significant impact on the ability of new entrants to compete in the market.[60] No apparent legal restrictions prohibit the building of LNG terminals in Japan. Nonetheless, new terminals must meet strict technical, safety, and environmental standards, which may delay terminal completion and increase construction costs.[61]

A final impediment to the development of a competitive market is the fact that roughly 80 percent of the LNG that Japan imports is purchased by electric and gas utilities through long-term, take-or-pay contracts that typically extend between 20 and 30 years.[62] Because the utilities would be fiscally penalized for early termination of their contracts, they are unlikely to participate in a trading, or wholesale, market for natural gas. In addition, the gas utilities, and other wholesale suppliers, have also established medium- to long-term contracts with smaller gas companies, which place further constraints on the development of a wholesale market.[63] However, long-term contracts between the gas utilities and overseas suppliers begin to expire in 2003, which may open up the possibility for new entrants, including traders, to supply LNG to the gas and electric utilities.[64]

Although industry sources did not identify any significant impediments to the participation of foreign firms in Japan's natural gas market, they did note that companies engaged in the domestic production of natural gas must establish a commercial presence. Foreign firms are reportedly accorded national treatment and are subject to the same licensing requirements with respect to the wholesale and retail supply of natural gas in Japan. Standards for the construction and operation of pipeline networks and LNG facilities also apply equally to foreign and domestic companies.[65]

[60] Industry representatives, interview by USITC staff, Tokyo, Japan, May 7, 2001.

[61] Government representatives also indicated that, as is the case for pipelines, different laws may be used to regulate the construction and operation of LNG terminals, depending on the objective of those terminals. Terminals built to supply gas to electricity generation facilities would be regulated under the Electric Utility Industry Law, and terminals used for the retail supply of gas would be regulated under the Gas Utility Law. Industry representatives and officials of the Government of Japan, interviews by USITC staff, Tokyo, Japan, May 7-9, 2001.

[62] Industry sources indicated that there are a few cases in which Japanese electric or gas utilities "trade" LNG while it is still being transported to Japan by ocean tanker. In particular, LNG shipments may be sold to another buyer and/or redirected to another LNG terminal than the one for which it was originally destined. However, such trades are infrequent because they are discouraged by "destination clauses" within contracts between the utilities and overseas LNG suppliers. Industry representatives, interviews by USITC staff, Tokyo, Japan, May 7-8, 2001.

[63] Industry representatives, interview by USITC staff, Tokyo, Japan, May 8, 2001.

[64] Industry representatives, interview by USITC staff, Tokyo, Japan, May 7, 2001.

[65] Industry representatives and officials of the Government of Japan, interview by USITC staff, Tokyo, Japan, May 7-9, 2001.

CHAPTER 8
REPUBLIC OF KOREA

Overview

The operations of the Korean natural gas market are divided into two distinct segments. The wholesale segment includes the importation of liquefied natural gas (LNG), the management of the LNG storage and regasification terminals, and the country's transmission pipeline network. The retail segment consists of 32 regional gas distribution companies, called city gas companies, which supply natural gas at the retail level for residential and commercial use. The wholesale segment of the market is controlled by the Korean Gas Company (KOGAS), which is majority-owned by the Korean Government. KOGAS is the only Korean firm licensed to import LNG. The firm supplies natural gas directly to KEPCO, Korea's electric power company, to steel producer POSCO, to private power plants, and to the city gas companies, which own and operate the local distribution pipeline networks.[1]

The Korean Government has formulated a plan to reform the wholesale segment of the industry, with retail segment reforms to follow at a later date. Under the plan, KOGAS will be broken up into three new companies, two of which will be privatized, and the monopoly over LNG imports will be eliminated. The third company, which likewise will serve importing and wholesaling functions, will retain the LNG terminals and transmission pipeline network. This company will remain majority owned by the government, although its importing and wholesaling functions may eventually be privatized as well. The plan also allows for third-party access to the transmission network.

In a first step toward privatization, KOGAS held an initial public offering in November 1999 in which the company listed shares on the Korean stock exchange, selling 43 percent of its equity to private investors. In January 2001, the limit on total foreign ownership of KOGAS shares was raised to 15 percent, from the previous 5-percent level.[2] Further reforms were announced in the Special Act on Privatization of Public Companies, passed in October 1997, and clarified by Korea's Ministry of Commerce, Industry, and Energy (MOCIE) in December 1999.

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[1] U.S. Department of Energy (USDOE), Energy Information Administration (EIA), "South Korea Country Analysis Brief," Sept. 2000, found at Internet address *http://www.eia.doe.gov/emeu/*, retrieved Sept. 12, 2000; and U.S. Department of Commerce (USDOC), International Trade Administration (ITA), International Market Insight, "Private City Gas Supply," May 12, 2000, found at Internet address *http://www.stat-usa/gov/*, retrieved Feb. 2, 2001.

[2] "KOGAS Expands Foreign Ownership Limit," *KOGAS Newsletter*, vol. 5, No. 1 (Jan. 2001), found at Internet address *http://210.124.38.1/newsletter/*, retrieved Jan. 31, 2001.

The Korea Gas Industry Division, established as a division of MOCIE in the first half of 2000, is charged with developing the details to implement the gas industry reform plan. This division will be reorganized into the Gas Industry Commission, an independent agency, in 2002. The new regulatory body will be responsible for the entire gas industry, including the wholesale, retail, and facilities management segments, and the system of open access to LNG facilities and the transmission network.[3] The gas regulatory body may eventually be merged with the regulatory body set up for the electric power industry.[4]

Industry Structure

Production and Imports

Korea currently imports all of its natural gas in the form of LNG through KOGAS. As of 1999, Korea's annual LNG demand was 13 million tons, projected to rise to 21 million tons by 2010.[5] Indonesia and Malaysia are the primary suppliers to the Korean market, with smaller amounts imported from Brunei, Qatar, Oman, and the United Arab Emirates. Import contracts generally have long terms of 20 years or more, and include "take or pay" clauses.[6] The Korea National Oil Corporation (KNOC) is in the process of developing an offshore gas field, expected to start producing in 2002, which will be Korea's first domestic source of natural gas. Once it is operational, the field is expected to supply 2 percent of Korea's gas needs.[7] Long-range plans are also underway to build Korea's first international natural gas transmission pipeline, which will extend 4,100 km, from Irkutsk, Russia, through Mongolia and China before terminating in Korea. KOGAS holds a 27-percent equity share of the consortium that is building the pipeline, which is not expected to begin operations until 2008. The entire project cost is estimated at $11 billion.[8]

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[3] Government representative, interview with USITC staff, Seoul, Korea, May 2, 2001; and "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001.

[4] Government representative, interview with USITC staff, Seoul, Korea, May 2, 2001; and "Restructuring Plan for Natural Gas Industry," Gas Policy Division, Ministry of Commerce, Industry, and Energy, Republic of Korea, found at Internet address *http://www.mocie.go.kr/work/gasrest.txt*, retrieved Jan. 31, 2001.

[5] USDOC, ITA, "Private City Gas Supply."

[6] "Restructuring Plan for Natural Gas Industry," Gas Policy Division, Ministry of Commerce, Industry, and Energy (MOCIE), Republic of Korea; and "Operational Review," KOGAS, found at Internet address *http://www.KOGAS.or.kr/,* retrieved Jan. 31, 2001.

[7] USDOE, EIA, "South Korea Country Analysis Brief."

[8] MOCIE, Public Information Office, press release, Sept. 8, 2000, found at Internet address *http://www.mocie.go.kr/*, retrieved Jan. 31, 2001; "KOGAS in the Future," KOGAS, found at Internet address *http://www.KOGAS.or.kr/*, retrieved Jan. 31, 2001; and "KOGAS Increases Equity in Irkutsk Project," *KOGAS Newsletter*, vol. 5, No. 1 (Jan. 2001), found at Internet address *http://210.124.38.1/newsletter/*, retrieved Jan. 31, 2001.

As noted above, under the current gas reform plan, KOGAS will be separated into three separate import and wholesale companies. Each of these will be assigned a share of KOGAS' long-term LNG import contracts, in such a manner as to ensure fair and transparent competition between the new companies. LNG transport ship assignments will also be divided to ensure fair competition. The Korean Government also plans to guarantee any loan defaults caused by the spinoffs, and to help cushion the financial impact of the changes in other ways.[9]

Current reform plans call for the breakup of KOGAS during 2001, and an auction of the import licenses for the two new import/wholesale companies during 2002.[10] The third import/wholesale company will remain under the control of KOGAS for an unspecified period of time to ensure proper servicing of previous gas orders. According to the reform plan, this company will eventually be privatized as well.[11] When the privatization of the first two new companies takes place, foreign investors will be limited to purchasing a total of 30 percent of each company's equity, with a limit of 15 percent of equity for any single foreign investor.[12]

As of June 2001, no steps had been taken to create the new companies, which will require passage of implementing legislation in the Korean National Assembly. The plan is expected to be submitted to the National Assembly in the fall of 2001, but there is significant opposition to reform, and passage is uncertain.[13] It remains possible that the reform plan will undergo significant changes before it is implemented. According to observers, the Government's primary incentive to proceed with the reform of the gas industry is to raise funds through private investment, rather than to lower prices or increase efficiency in the industry. Lowering the price of natural gas is not the greatest concern. Korean prices are already lower than those in Japan and Taiwan, two countries that are also highly dependent on LNG, and security of supply has always been of greater concern in Korea than lowering gas prices.[14]

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[9] "Gov't Finalizes Gas Industry Overhaul Plan," *The Korea Herald*, Nov. 13, 1999, found at Internet address *http://www.koreaherald.co.kr/,* retrieved Feb. 21, 2001.

[10] Industry representatives and Korean Government officials, interviews by USITC staff, Seoul, Korea, May 2-4, 2001; MOCIE, Republic of Korea, Gas Policy Division, "Restructuring Plan for Natural Gas Industry;" "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001; and KOGAS, found at Internet address *http://www.kogas.or.kr,* retrieved May 9, 2001.

[11] "State-Run KOGAS to Hold Investment Seminar Abroad," *The Korea Herald*, Mar. 21, 2000, found at Internet address *http://www.koreaherald.co.kr/,* retrieved Feb. 21, 2001; MOCIE, Gas Policy Division, "Restructuring Plan for Natural Gas Industry;" and "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001.

[12] "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001.

[13] Government officials and industry representatives, interviews by USITC staff, Seoul, Korea, May 2-4, 2001.

[14] Industry representatives, interviews by USITC staff, Seoul, Korea, May 4, 2001.

Transmission and Distribution

As of the end of 1999, KOGAS had two LNG terminals in operation, at Pyongtaek and Inchon, incorporating 19 LNG storage tanks. A third terminal, at Toungyoung, is scheduled to be completed in 2002.[15] The KOGAS transmission pipeline network reached 1,955 kilometers (km) at the end of 1999, with a scheduled expansion to 2,435 km by 2002 (figure 8-1).[16] According to the current reform plan, all market participants will have open access to the transmission network, LNG terminals, and storage facilities in 2003, once the breakup of KOGAS has been completed. The Korean Government plans to retain ownership control over the remaining KOGAS facilities, at least in the short term, to safeguard the public interest in the gas industry, but plans to sell off a portion of the company to private investors in order to raise capital. The exact share to be sold off had not been announced by June 2001, and will be decided by MOCIE's Korea Gas Industry Division. The remainder of the Government's shares may eventually be sold to private investors.[17]

KOGAS also controls four subsidiary companies that perform services integral to the gas industry, all of which are scheduled to be privatized. The first, KOGAS Gas Marine Transportation Co., was sold to private Korean investors in 2000.[18] The others (KOGAS Maintenance and Engineering Co., KOGAS Engineering and Construction Co., and KOGAS LNG Co.) will be privatized as soon as possible.[19]

There were 32 city gas companies in Korea as of June 2001, all privately owned regional monopolies. Most supply natural gas through pipelines, although six city gas companies exclusively supply liquefied petroleum gas (LPG) through tanker trucks. Several of the latter have gas pipelines under construction.[20] In 2001, the city gas companies were expected to supply a total of 12.1 billion cubic meters of gas to their customers, through 17,846 km of pipelines.[21] On average, 58 percent of homes and businesses within each gas company's territory have access to natural gas. This penetration rate is projected to rise to 76 percent by 2010, greatly increasing the overall size of the gas market.[22] MOCIE has predicted that annual LNG demand from city gas companies will reach 14.9 million tons by 2010, an average annual growth rate of 4 percent. This includes demand from residential,

[15] USDOC, ITA, "KOGAS Toungyoung LNG Receiving Terminal," International Market Insight Report, Oct. 9, 1998, found at Internet address *http://www.stat-usa.com/*, retrieved Feb. 2, 2001; and USDOC, ITA, "Private City Gas Supply."

[16] KOGAS, found at Internet address *http://www.kogas.or.kr/*, retrieved Apr. 5, 2001.

[17] "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001.

[18] Ibid.

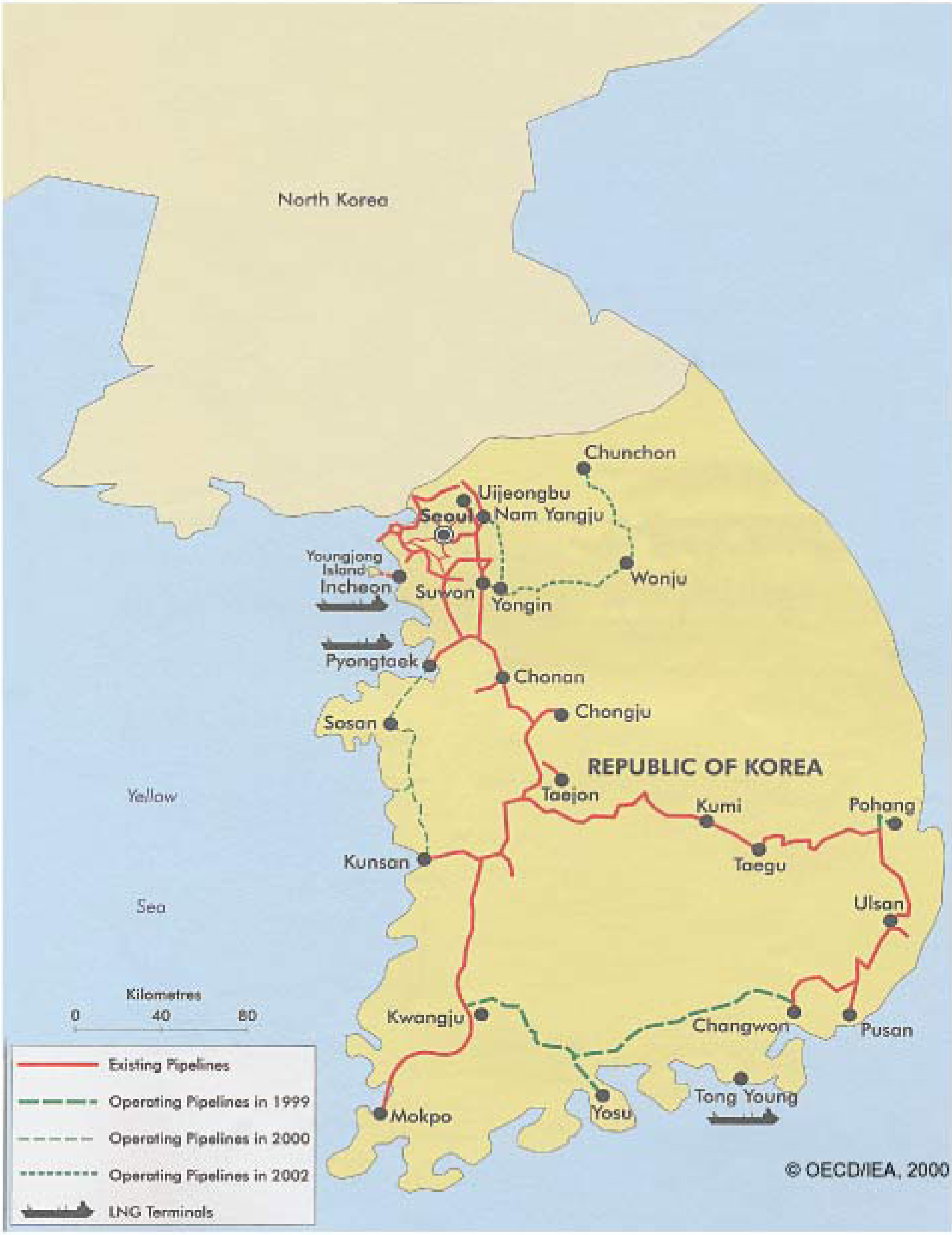
[19] MOCIE, Gas Policy Division, "Restructuring Plan for Natural Gas Industry."

[20] Industry representative, USITC staff interview, Seoul, Korea, May 3, 2001; and Korea City Gas Association, "Conditions of City Gas Business in Korea," Seoul, Korea, 2001.

[21] Korea City Gas Association, "Conditions of City Gas Business in Korea,"

[22] KOGAS, *Annual Report 1999*, p. 9.

Figure 8-1
Natural gas pipelines in Korea



Source: Used with permission from the Organization for Economic Cooperation and Development, International Energy Agency. Maps obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition.*

commercial, and industrial users, but excludes demand from electric power generation plants and POSCO, which receive gas directly from KOGAS trunk lines.[23]

The distribution segment of the industry is the only segment in which foreign investors are actively participating.[24] In December 1998, Enron (U.S.) signed a joint-venture agreement with SK Corporation, Korea's largest oil refinery firm, for the purpose of entering the gas distribution market.[25] SK-Enron, with nine city gas subsidiaries, holds 25 percent of the city gas market.[26] The joint venture is working to expand Korea's distribution pipeline network. SK Corp. is contributing its existing stakes in Korea's city gas companies, and Enron is contributing a reported $450 million in capital to the expansion efforts.[27] Caltex Corporation, a Singapore-based joint venture of U.S. oil companies Chevron and Texaco with a large petroleum business in Korea, has formed LGCaltex Gas Co., Ltd., a joint venture with Korean-based LG Corporation. LGCaltex Gas Co. owns four city gas companies, comprising a 10-percent share of the city gas market.[28] The company is also involved in supplying LNG for power generation and district heating facilities, and operates an extensive network of petroleum facilities and service stations in Korea.[29]

Korea plans to introduce competition into the retail distribution segment of the gas industry in phases, following the implementation of the wholesale industry reform plan. In the first phase, which began in 2000, any certified company is permitted to construct and operate distribution facilities in areas which do not already have access to gas service. Retail gas companies may also provide LNG through tanker trucks in areas without a distribution pipeline network. Observers predict that the city gas companies will undergo a further wave of consolidation as reforms are implemented, and that the three Korean-foreign joint venture firms will likely acquire most of the remaining independent firms when the KOGAS reform legislation is passed.[30] In the next phase of retail competition, MOCIE plans to permit competition among two or three retail distribution firms in each region that is currently subject to a regional monopoly.[31] The plan also envisions dividing the city-gas supply companies into two parts, one for marketing, the other for the operation of gas facilities. However, there is no set timetable for such reforms.[32]

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[23] Industry representative, USITC staff interview, Seoul, Korea, May 3, 2001; and USDOC, ITA, "Private City Gas Supply."

[24] There is limited foreign equity participation in KOGAS.

[25] USDOC, ITA, "Enron Makes Inroads," International Market Insight Report, Dec. 18, 1998, found at Internet address *http://www.stat-usa.com/*, retrieved Feb. 2, 2001.

[26] U.S. Commercial Service, Seoul, Korea.

[27] Industry representative, interview with the Commission, Washington, DC, Feb. 23, 2001; and USDOE, EIA, "South Korea Country Analysis Brief."

[28] U.S. Commercial Service, Seoul, Korea.

[29] Ibid., and Caltex Corporation, found at Internet address *http://www.caltex.com/media/*, retrieved Apr. 5, 2001.

[30] Industry representative, USITC staff interview, Seoul, Korea, May 3, 2001.

[31] Industry representatives, USITC staff interviews, Seoul, Korea, May 3-4, 2001.

[32] "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001.

Markets and Pricing

Under current rules, KOGAS is Korea's sole importer of LNG, all of which passes through KOGAS' storage and regasification terminals. KOGAS sells natural gas to electric power generation plants, to the city gas companies and, in a few cases, directly to other large customers such as POSCO. According to the December 1999 gas reform plan, these large customers are permitted to directly import LNG for their own use as of 2001. None is currently doing so, however, since independent importers cannot now use KOGAS terminals, and building LNG receiving terminals is not economically feasible for customers apart from POSCO.[33] Beginning in 2003, independent importers will be able to import LNG through KOGAS terminals, which will likely make such imports more feasible. POSCO plans to begin importing LNG through its own receiving terminal, due to be completed in 2005. The company's primary motivation for building its own receiving terminal is to assure a ready supply of LNG, rather than to limit costs.[34]

Korean natural gas prices are currently set by regulation, not by market competition. MOCIE sets wholesale gas prices and authorizes all price changes, following consultation with the Ministry of Finance and Economy. KOGAS customers pay a single, bundled price, which covers both the cost of the LNG and the cost of facilities such as transmission pipelines and LNG terminals.[35] Prices are set using a cost-plus methodology, taking into account world market prices for natural gas, long-term interest rates, and the cost of facilities. Wholesale gas prices are reviewed every 3 months, and transmission prices once a year.[36] Once the gas industry reforms take effect, city gas companies will be able to choose whether or not to pay through this bundled pricing system. Customers which do not pay a bundled price will most likely be able to negotiate the import price with KOGAS, while the facilities price will remain standard for all customers.[37] Until retail market reforms take place, mayors or provincial governors will continue to authorize all price changes for city gas supply services, using a cost-plus formula that establishes a set rate of return.[38]

Reform plans envision an open access system for the use of LNG terminals, storage facilities and high pressure gas transmission pipelines, which is intended to lead to market competition in the wholesale segment of the industry. The plans for reform of the retail segment of the industry outlined above will also introduce market competition into that segment. However, there is no set timetable for such retail competition to begin. Korea's public reform plans do not mention any type of gas

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[33] Ibid.; and industry representatives, USITC staff interview, Seoul, Korea, May 2, 2001; MOCIE, Gas Policy Division, "Restructuring Plan for Natural Gas Industry,"; and "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001.

[34] Industry representatives, USITC staff interview, Seoul, Korea, May 3, 2001; and USDOC, ITA, "Private City Gas Supply."

[35] The cost of facilities includes transmission, storage, and maintenance costs.

[36] Government officials, USITC staff interview, Seoul, Korea, May 2, 2001.

[37] Industry representatives, USITC staff interviews, Seoul, Korea, May 2-3, 2001.

[38] Government officials, USITC staff interview, Seoul, Korea, May 2, 2001; and MOCIE, Gas Policy Division, "Restructuring Plan for Natural Gas Industry."

trading system. Initially, MOCIE will permit the resale of natural gas only under special circumstances. However, industry representatives envision a limited gas trading pool, allowing import/wholesale companies, city gas companies, and large users such as POSCO and KEPCO to match excess supply and demand. Eventually, all large users are expected to purchase their gas through a central gas exchange.[39]

Impediments to Competitive Market Development

There is currently no competition in the importing and wholesale segments of the industry, as KOGAS holds a nationwide monopoly on the natural gas industry. The planned reforms will introduce only limited competition in Korea's natural gas industry. The three import/wholesale companies envisioned by the reform plan will compete to supply natural gas to Korea's large users, particularly the city gas companies and electric power companies, unless those users choose to import their own LNG supplies. However, the true extent of competition remains unclear under this scenario. Observers have expressed concern over the possibility of KOGAS using its transmission business to subsidize its remaining import/wholesale unit.[40] As of June 2001, there were no plans to split these businesses into separate companies, to create discrete transmission/storage and import/wholesale subsidiaries under a holding company arrangement, or to erect some form of administrative separation between them. It will be the responsibility of the regulators to ensure that this system does not accord a competitive advantage to the importing firm that remains part of KOGAS, and that KOGAS' importing firm does not receive preferential access to the transmission system.[41]

Another concern is that all three of the competing LNG import companies will be bound by long term (20-years and more) contracts signed by KOGAS, the first of which expires in 2007.[42] This would seem to leave little room for competitive pricing. As of June 2001, it is unclear whether firms will be free to establish import/wholesale companies in addition to the three formed by the breakup of KOGAS, although some observers expect auctions for additional licenses beginning in 2007, with the expiration of the first long-term import contracts.[43]

In the retail segment, the system of regional monopolies precludes competition. New entrants are only permitted in areas without previous access to natural gas service, via the construction of new pipelines or by providing service through LNG tanker trucks. However, significant expansion of the gas distribution pipeline network is not economically feasible at this time. The areas without current access to natural gas distribution systems are either too mountainous to construct pipelines, or do not have

[39] Government officials, USITC staff interview, Seoul, Korea, May 2, 2001.
[40] Industry representatives, interviews with USITC staff, Seoul, Korea, May 3-4, 2001.
[41] Government and industry representatives, interviews with USITC staff, Seoul, Korea, May 2-4, 2001.
[42] KOGAS, *KOGAS Annual Report 1999*, p. 15.
[43] Industry representative, interview with USITC staff, Seoul, Korea, May 3, 2001.

markets large enough to provide adequate return on such an investment.[44] Tanker truck service does not seem to be a feasible market entry alternative either. KOGAS predicts that demand for such service will rise over the next 10 years, with KOGAS supplying the city gas companies and large industrial customers that currently use LPG. However, the cost of such service is high. Customers must invest up to $4 million to construct regasification and storage facilities, and LNG supplied through tankers will cost 20 to 50 Korean won per cubic meter more than natural gas supplied through pipelines. Due to these high costs, the city gas companies are rethinking their interest in tanker service, and no new market entrants have expressed an interest in providing natural gas service through tanker trucks.[45]

Reform plans call for eventual competition in retail sales in the areas currently served by the monopoly city gas companies, allowing retail customers to choose between two or three competing gas suppliers. However, no further details are available, and the reform plan explicitly states that competition in the retail segment of the industry will begin after the introduction of competition into the wholesale segment. Entry into the market controlled by the existing city gas companies is likely to be difficult for Korean and foreign firms alike, given the entrenched nature of the existing regional monopolies. Significant market reforms and close supervision by the new regulatory agency will likely be necessary for market competition to flourish.

Beyond these significant impediments to competition faced by all firms seeking to enter Korea's natural gas industry, non-Korean firms are confronted with additional limitations. Total foreign ownership of KOGAS shares is limited to 15 percent of the company.[46] The two import/wholesale companies to be spun off from KOGAS will have total foreign equity ownership limits of 30 percent, with individual foreign firms limited to owning 15 percent of either company.[47] In the retail distribution segment of the industry, on the other hand, the Caltex and Enron joint ventures demonstrate that foreign participation, including foreign majority ownership, are possible in the city gas companies.

Additional market access opportunities exist in the retail distribution segment, even though no reforms are planned to create competition. Although the city gas companies are regional monopolies, much of the country is not served by gas distribution pipelines, and as noted above, any company willing to invest in construction of the infrastructure can offer gas service in these areas. It is not clear whether the firm then acquires a new regional monopoly in exchange for its infrastructure investment. It is also possible for new entrants into the market to serve areas not currently served by the regional monopolies by creating an LNG distribution system through tanker trucks rather than pipelines, significantly reducing the initial cost of market entry. It does not appear that tanker truck service may be provided in areas currently served by monopoly city gas companies.

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[44] U.S. Commercial Service, Seoul, Korea, and email communication from industry representative, Seoul Korea, received June 11, 2001.

[45] U.S. Commercial Service, Seoul, Korea.

[46] "KOGAS Expands Foreign Ownership Limit," *KOGAS Newsletter*.

[47] "KOGAS Privatization Plan Released by MOCIE in December 1999," communication from U.S. Embassy, Seoul, received Feb. 21, 2001.

CHAPTER 9
MEXICO

Overview

Prior to 1995, the Mexican natural gas industry was primarily state owned and controlled through the Ministry of Energy[1] (SE) and *Petróleos Mexicanos* (Pemex). The SE held policy and administrative duties, while Pemex, a state-owned and self-regulated monopoly, was responsible for virtually all operational activities within the entire petroleum products industry. This configuration created economic, regulatory, and legal conditions that limited the introduction of competitive conditions, affecting both price and quality of service while discouraging efficient use of Mexico's significant natural gas reserves. Also, restrictions on private investment eliminated a potential source of capital, which during the mid-1990s was increasingly needed for maintenance, expansion, and improvements to the industry's infrastructure. To improve these conditions, the Mexican Government began restructuring the industry in the mid-1990s, with a major objective of providing investors with a transparent and credible regulatory regime backed by an enforceable legal framework.

One of the Government's early initiatives was the *1995-2000 Program for the Development and Restructuring of the Energy Sector,* which introduced preliminary policy guidelines for promoting long-term development of the natural gas industry. The program's objectives included meeting the national demand for natural gas, maintaining international competitiveness, conforming with newly established environmental standards, promoting competition, and attracting investment.

In 1995, several articles of legislation were enacted that reorganized the industry's participants and redefined their powers and responsibilities. In May, the Mexican Congress amended the "Regulatory Law of Constitutional Article 27 on Petroleum"[2] (Oil and Gas Ruling Act), allowing private sector participation in several activities previously reserved for Pemex. By law, national and foreign investors were now permitted to build, operate, and own natural gas transportation, storage, and distribution systems.[3] The regulation also allows all entities to import, export, and market natural gas. Although the Mexican Government was willing to liberalize certain segments of Pemex, complete privatization remains unlikely due to complex political, economic, and national identity considerations.[4]

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[1] *Secretaría de Energía.*

[2] *Ley Reglamentaria del Artículo 27 Constitucional en el Ramo del Petróleo.*

[3] Pemex's exclusive rights to exploration and production of natural gas, as well as to first-hand sales, were retained.

[4] Pemex has been a symbol of national sovereignty and economic independence since the modern Mexican energy industry was established. Pemex also maintains strong ties with Mexico's Administration and accounts for a significant portion of Mexico's state revenue. Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

In October 1995, the Mexican Congress enacted the Energy Regulatory Commission Act, which granted the Energy Regulatory Commission[5] (CRE) autonomy from the SE.[6] The CRE became the sole regulatory authority for the electricity and natural gas industries, centralizing powers previously dispersed among various agencies. The CRE was to oversee the introduction of investment and competition, improve the transparency of regulations, and ensure unilateral or discriminatory conditions did not exist. The CRE's administrative duties include granting and revoking permits, enforcing regulations, and settling disputes. The CRE also sets Pemex's wholesale prices.

The Natural Gas Regulation[7] (RGN) was issued in November 1995, setting guidelines for the regulatory policies established by the amendments to the Oil and Gas Ruling Act. Issues addressed include allocation of permits, wholesale and retail pricing, and rates for transportation, distribution, and storage. The RGN guarantees third-party access to all existing and newly constructed transportation and distribution networks, provided that sufficient capacity is available. Restrictions on foreign trade were also eliminated. The RGN provides for the partial unbundling of natural gas transportation services from gas marketing services. Although the RGN requires all firms to maintain an accounting separation between business segments to comply with prohibitions on cross-subsidies, Pemex continues to engage in both supply and transportation activities.

In late 1995, the CRE began updating the natural gas industry's regulatory framework and the recently enacted reforms. Several directives were issued to clarify and offer additional governance on issues including pricing, acceptable accounting principles and procedures, and the methodology for determining distribution zones. A number of "Official Mexican Standards" were also published, setting technical and safety standards for the natural gas industry.

Industry Structure

Production and Imports

Pemex remains Mexico's sole producer of natural gas and retains exclusive rights on exploration and processing activities. Mexico's natural gas reserves are estimated at 2 to 3 trillion cubic meters, ranking ninth in worldwide national reserves. Within Latin America, Mexico has the second-largest share of reserves, behind Venezuela and ahead of Argentina. Most of Mexico's natural gas is a byproduct of oil production and is referred to as "associated", or "wet", gas. Petroleum production is concentrated in the Southeastern States and offshore, while the population is concentrated inland and to the north. Significant reserves of nonassociated gas are being developed in the Burgos Basin in northeastern Mexico, as well as in the Gulf of Mexico.

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[5] *Comisión Reguladora de Energía.* The CRE was initially an advisory body within the SE.

[6] The SE would now focus on Mexico's national and international energy policy.

[7] *Reglamento de Gas Natural.*

In 1998, Mexico produced 35.9 billion cubic meters of natural gas and consumed 36.4 billion cubic meters.[8] Of this, the industrial sector consumed 58 percent, electricity production, 20 percent and the energy/oil sector, 18 percent.[9] Although residential and commercial consumption currently account for only 3 to 4 percent of total consumption, the sectors are considered underdeveloped markets with strong growth potential.[10]

Mexico's demand for natural gas is expected to grow at 10 percent a year for the next 10 years. Electricity generation will likely account for a large share of the increase, as the Mexican Government moves towards cleaner fuels. To meet this demand, the Mexican Government reportedly plans to more than double natural gas production by 2008, which would require an estimated $2 billion a year for additional exploration, extraction, and processing.[11] Consequently, Mexico's consumption of natural gas is expected to increasingly outpace supply unless additional sources are developed. Options include improving productivity and increasing recovery rates,[12] although the size of the deficit will likely require opening Pemex's reserved activities to private investment, increasing imports, and/or developing large-scale liquefied natural gas (LNG) import capabilities.[13]

Imported natural gas is likely to be the most effective solution to Mexico's deficit. Amendments to the Oil and Gas Ruling Act in 1995 allow private sector firms to import and export natural gas, thereby avoiding the State's restrictions on domestic production. Further, any firm wishing to engage in these activities may do so by accessing Pemex's network. No license or permit is required to import or export natural gas, and all tariffs and duties have been eliminated.

Currently, the United States is Mexico's only natural gas trading partner. In 1999, Mexico exported 1.4 billion cubic meters of natural gas to the United States, while importing 1.7 billion cubic meters.[14] Both Mexico and the United States are

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[8] Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA), *Natural Gas Information,* (OECD, 2000) p. IV.249.

[9] Pemex is Mexico's largest user of natural gas.

[10] A major impediment to developing Mexico's residential market is having a substantial portion of the population that is too poor to be considered potential customers.

[11] Industry representatives believe Pemex will be unlikely to be able to fund such expansion. Industry representatives, interviews by USITC staff, Mexico City, Mexico, May 2001.

[12] In 1990, most associated gas was flared, while in 2000, 90 percent was recovered.

[13] Industry representatives, interviews by USITC staff, Mexico City, Mexico, May 2001.

[14] OECD, IEA, *Natural Gas Information*, p. IV.249.

increasing their ability to trade natural gas with one another.[15] Among other projects, a $230 million, 215-mile pipeline is currently being jointly developed by U.S. and Mexican firms to bring natural gas from Arizona to Baja California.[16]

LNG is expected to play an increasingly important role in meeting Mexico's demand for natural gas. Currently, LNG imports are quite small, although construction of LNG terminals on Mexico's east and west coasts is considered likely.[17] Pemex is considering a joint-venture to build a LNG terminal at the Gulf coast port of Altamira that would offload imports from Trinidad and Tobago, Venezuela, and Algeria. On Mexico's west coast, several private sector firms have announced preliminary plans to develop a LNG terminal that would source natural gas from Asia and South America. A large portion of this natural gas is likely to be used to produce electricity that would be exported to southern California.

Transmission and Distribution

In May 1995, the Mexican Constitution was amended to allow both national and foreign investors to build, own, and operate natural gas transportation, distribution, and storage systems (figure 9-1). Investment in these activities is not in any way limited, such as by restrictions on foreign ownership. The CRE granted 84 gas transportation and distribution permits from 1996 to August 2000, accounting for 40,000 kilometers of new pipeline and more than $2 billion of investment.[18] Although private participation has been allowed in the transmission segment since 1995, Pemex controls most of Mexico's natural gas transport facilities, which serve all of Mexico's major industrial centers except those in the northwest. Consequently, opportunities for private transportation firms are limited.[19]

Transportation, distribution, and storage activities require a CRE permit. Permits are granted for 30 years and may be renewed for 15-year periods. Additional permits or approvals may be required, such as those required by the Federal environmental

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[15] Presidents Bush and Fox have reportedly discussed the possibility of the United States lending Pemex funds to increase production of natural gas, although the increased production would be exported to the U.S. market. Even so, some industry representatives believe this would be a first step towards opening the remaining restricted segments of Pemex to private investors. "Bush, Fox to Discuss Energy Accord," *Business News Americas - Oil & Gas,* Feb. 16, 2001.

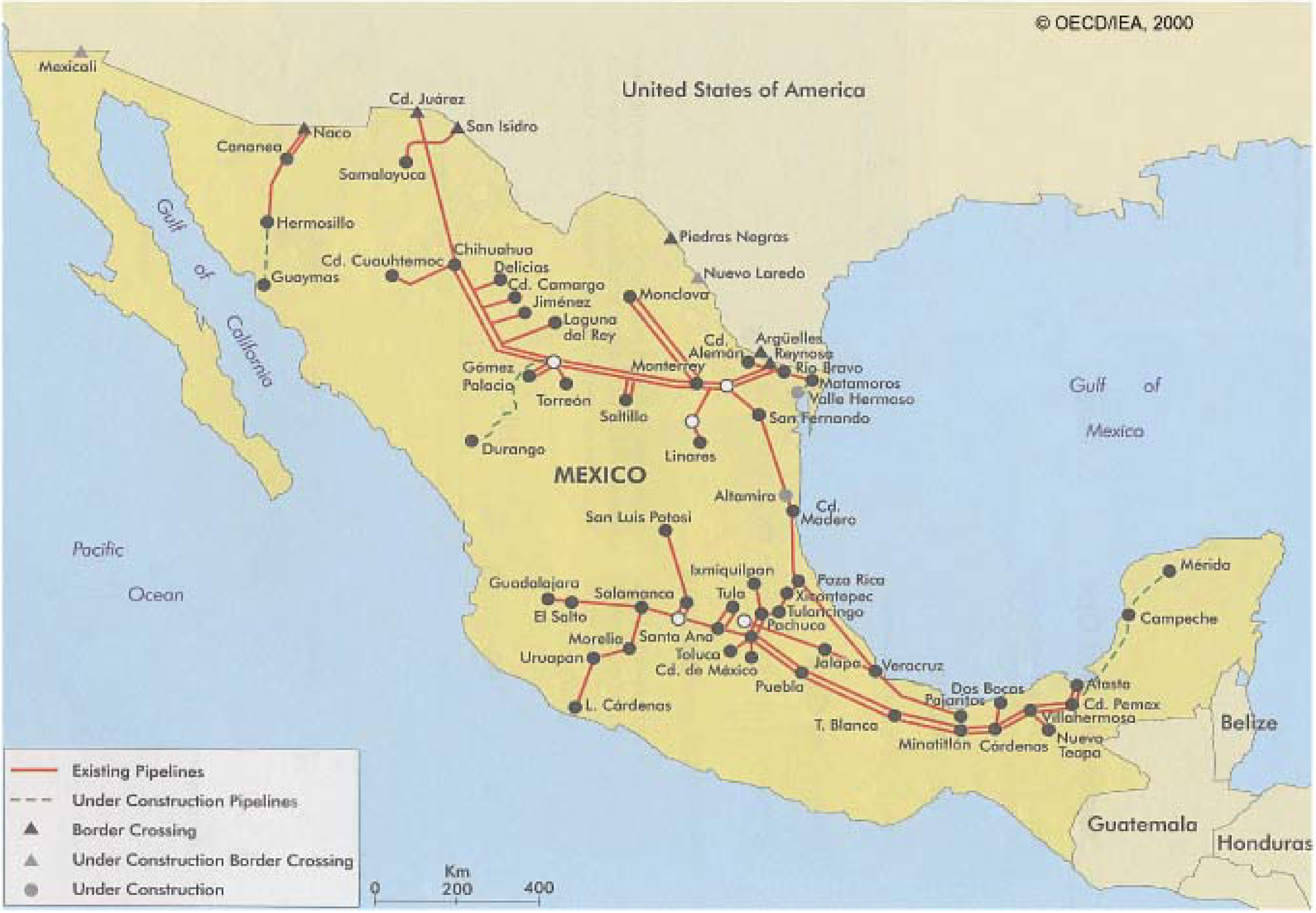
[16] The North Baja Pipeline is expected to be operational mid-2002 and will primarily fuel new power plants being built in Mexico. Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

[17] Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

[18] Of the 84 permits, 63 were for transportation (49 self-use and 14 open access) and 21 were for distribution. CRE, *Five-Year Report: 1995-2000,* Oct. 2000, p. 3.

[19] Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

Figure 9-1
Natural gas pipelines in Mexico



Source: Used with permission from the Organization for Economic Cooperation and Development, International Energy Agency. Maps obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition.*

regulatory agency[20] or local governments.[21] Distribution permits are issued for specific geographic zones. The CRE has defined 21 zones that comprise Mexico's four major metropolitan areas (Mexico City, Guadalajara, Monterrey, and Puebla), as well as almost one-third of the larger cities. Firms may contract for a specified amount of capacity and if this exceeds their needs, they may assign their capacity rights to other users or authorize other firms to resell the unused capacity.

Transmission and storage permits are granted upon application and do not provide exclusivity. The CRE grants distribution permits through a public bidding process that requires candidates to submit technical and financial proposals, as well as market demand studies. Among other factors,[22] distribution concessions are granted to the firm that guarantees both the lowest average rate expected to be charged to customers and the highest estimated customer coverage by the end of the fifth year.[23] The winning bidder takes title to any existing infrastructure and receives a 12-year period of exclusivity to deliver natural gas within an assigned region.[24]

Markets and Pricing

By terminating the monopoly rights of Pemex to the transportation and marketing of natural gas, Mexico's reforms have made it possible for new entrants to compete to build pipelines, acquire distribution franchises, and market gas to consumers. However, since Pemex retains its monopoly over domestic production, the wholesale price for gas remains regulated. This means that gas marketers will have difficulty competing on the basis of price unless they import their supplies. In addition, the exclusivity periods granted to winners of distribution tenders limit the number of customers who are free to choose an alternative gas marketer. Consequently, in practice, only the largest industrial customers and distribution companies have a real choice of service provider, and most consumers continue to pay regulated rates.

[20] Obtaining environmental approval is reportedly one of the most challenging aspects of obtaining transportation and distribution permits. Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

[21] Industry representatives report that while complying with the CRE is a relatively transparent and straight-forward process, complying at the sub-federal level is often uneven, cumbersome, and costly. The CRE plans to work with industry and local governments to help effectuate a more mutually beneficial process. Industry representatives, interviews by USITC staff, Mexico City, Mexico, May 2001.

[22] Proposals also include estimated natural gas consumption within the region, a breakout of residential, industrial, and commercial users, and the total amount the firm will invest.

[23] The CRE and distributors are preparing for the first round of 5-year reviews. The distributors are somewhat apprehensive of the review because they are unsure of how the CRE will react to contracts with terms and conditions that have not been fully met. Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

[24] This arrangement essentially creates temporary monopolies within the zones.

Wholesale prices are determined using a netback formula that links the price of gas in the Houston ship channel[25] with the price at Ciudad Pemex (Pemex City), a major production site in southeastern Mexico. This methodology bases the price of natural gas on its opportunity cost and introduces competitive conditions by linking Mexican prices to the competitive U.S. natural gas market. Variables used to calculate the price of natural gas for a customer located anywhere in Mexico include reference prices in northern and southern Mexico, an arbitrage point, and transportation costs. The arbitrage point, currently at Los Ramones, is where transportation costs from both northern and southern sources are equal. The maximum[26] wholesale price for natural gas is equal to the price in Houston, plus transport costs to the arbitrage point, less transport costs from the arbitrage point to Ciudad Pemex.

Rates for captive consumers are regulated using a price cap. Captive customers are residential and commercial consumers in a region where a firm has been granted exclusive rights to market and distribute natural gas. For such customers, the CRE determines the maximum amount a distributor may pass through to the final user to cover wholesale purchase, transportation, distribution, and storage costs.[27] This method allows distributors to transfer the cost of acquiring gas, if it is less than or equal to the price cap. If the distributor sells imported gas, the CRE may authorize a reference price different from the regulated price of domestically-produced gas.

In early 2001, the price of natural gas in the United States rose sharply. This led to higher prices in Mexico, as the CRE's wholesale pricing methodology is partially based on U.S. prices. The price rise was particularly detrimental to the Mexican economy because most firms purchased gas using short term contracts. Futures contracts were not considered necessary because Mexico's fairly consistent weather eliminated seasonal spikes in demand and, in the past, supply prices had been fairly predictable and dependable.[28] Also, entering into financial contracts was not a widely accepted business practice within the natural gas industry.[29] Consequently, some of Mexico's largest industrial firms cut back operations and laid off workers, reportedly because of exorbitant fuel costs. In response, the Mexican Government offered to sell natural gas to the domestic industry at a fixed price of $4 per million British thermal units (mBtu) for the next 3 years. Under the arrangement, Pemex will cover the

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[25] The Houston ship channel is a natural gas trading hub located near a major connection between the U.S. and Mexican pipeline systems.

[26] Current regulations specify that Pemex may sell below the maximum price, if it does so in a nondiscriminatory fashion.

[27] The CRE sets transportation and distribution rates based on a revenue yield cap methodology, which provides incentives for permit holders to increase their client base and improve their quality of service.

[28] Over the summer in 2000, Pemex and several regional distributors of natural gas offered futures contracts that could have guaranteed stability to these businesses, but few took advantage of the contracts. Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

[29] Hedging within the natural gas markets is allowed, but has been generally considered more a form of "gambling" rather than a sound financial strategy. Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

difference if natural gas prices rise above $4/mBtu, although customers will pay the established price if international prices fall below the reference price.[30]

Impediments to Competitive Market Development

Industry representatives have mixed views of Pemex's offer to charge a fixed price of $4/mBtu[31] for 3 years. On the one hand, Mexican consumers of natural gas clearly needed some type of price relief. However, some believe these contracts will slow the deregulation process because competition will have little chance of entering the market once users are locked into long-term contracts with Pemex.[32] Also, the government contracts effectively stifled the fledgling financial contracts market.

After reforms to the Mexican natural gas industry in the mid-1990s, foreign and domestic investment capital flowed rapidly into the market. However, investment peaked in 1998 and then declined rapidly. Pemex's stature within the industry appears to remain an impediment to the development of a competitive market. Pemex's continued legal monopoly over natural gas exploration and production[33] eliminates any participation by third parties and decreases competition within the overall industry.[34] Pemex also maintains a de facto monopoly over the national pipeline system. Having control over both these market segments severely restricts the development of marketing activities by an outside party. Further, Pemex continues to build transportation pipelines, related primarily to electricity projects. This situation runs counter to the objectives of the 1995 reforms, as Pemex is devoting resources to projects that are open to private participation, instead of concentrating on activities reserved for the State. Another shortcoming involves the lagging development of natural gas storage systems. Sufficient storage systems would allow unexpected changes in gas demand and production to be efficiently confronted and sudden price fluctuations to be moderated.

In part to address these market impediments, the CRE issued the Directive on *Firsthand Sales of Natural Gas* in February 2000. Pemex's vertical integration in production, transportation, and marketing was identified as an obstacle to introducing competition and to achieving compliance with CRE regulations. The directive requires Pemex to unbundle its production, transportation, and marketing activities, and stipulates that Pemex may not make cross-subsidies between marketing activities and firsthand sales. Further, Pemex would be required to present the CRE with detailed

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[30] Within a month, all the distribution companies operating in Mexico as well as Pemex's major industrial clients signed up for the 3-year contracts. The contracts entered into force, retroactively, on January 1, 2001. Natural Gas Intelligence, "Mexico's Pemex fixes Natural Gas Prices," Intelligence Press, Inc., Jan. 18, 2001, found at *http://intelligencepress.com/*.

[31] When offered the price was less than half the current official reference price of more than $9/mBtu.

[32] Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

[33] Although imports are allowed, they remain insignificant and have no impact on the monopoly environment.

[34] Industry representative, interview by USITC staff, Mexico City, Mexico, May 2001.

information on its marketing activities, transportation, distribution, and storage contracts, as well as on gas sales, prices, gas availability, import and export volumes, national gas balance, and methodologies for price discounts.

CHAPTER 10
SPAIN

Overview

Spain initiated regulatory reform of its natural gas market with the passage of the Hydrocarbons Act 34/1998, which became law on October 9, 1998.[1] Formerly, the provision of natural gas services had been a state responsibility, which was fulfilled by granting concessions to public and private companies. Under the Hydrocarbons Act, the state is no longer obliged to provide natural gas services, but participants in the gas market must obtain authorization from the state to operate in Spain, and natural gas activities are subject to regulation.[2] Among other provisions, the Hydrocarbons Act created a retail market for natural gas, permitted the construction of natural gas facilities (subject to authorization),[3] and guaranteed regulated third-party access to transmission, storage, distribution, and regasification facilities.[4] Integrated firms are required to maintain accounting separation between regulated activities, whereas legal separation must be maintained between regulated and unregulated activities, which principally include marketing.[5] The Hydrocarbons Act also established a timetable for the gradual opening of Spain's natural gas market to consumer choice.[6] Since the passage of the Hydrocarbons Act, this schedule has been accelerated twice. The most recent schedule permits all consumers to choose their natural gas marketer by January 2003,[7] which exceeds the liberalization standard set by the EU Natural Gas Directive (see text box 10-1).

The privatization of state-owned natural gas firms preceded regulatory reform in Spain. The oil firm Repsol was privatized gradually between May 1989 and April

[1] Comisión Nacional de Energía (CNE), *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*, Dec. 2000, found at Internet address *http://www.cne.es/*, retrieved Feb. 9, 2001.

[2] Organization of Economic Cooperation and Development (OECD), "Promoting Competition in the Natural Gas Industry," Oct. 23, 2000, found at Internet address *http://www.oecd.org/*, retrieved May 3, 2001; and CNE, *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*.

[3] CNE, *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*.

[4] Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st edition, 1999, pp. 99-100.

[5] European Commission, *State of Implementation of the EU Gas Directive (98/30/EC): An Overview*, May 2000, found at Internet address *http://europa.eu.int/comm/energy/en/gas_single_market/index_en.html*, retrieved Jan 31, 2001; and OECD, "Promoting Competition in the Natural Gas Industry."

[6] *CNE, National Energy Regulatory Commission (CNE) Cronology, 1998-2000*.

[7] European Commission, *State of Implementation of the EU Gas Directive (98/30/EC): An Overview*; and CNE, *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*.

Box 10-1
The EU Natural Gas Directive[1]

European Union Member States annually account for about 10 percent of production and 17 percent of consumption of the world's natural gas.[2] As a group, they are a net importer of natural gas, and currently produce about 60 percent of their gas consumption. Natural gas provides 22 percent of the energy demand in the European Union.[3] EU Member States have a total of 114.9 trillion cubic feet of natural gas reserves, mostly in the North Sea, of which 62.5 trillion cubic feet belong to the Netherlands, 26.7 trillion cubic feet to the United Kingdom, and 12 trillion cubic feet to Germany. The balance of EU gas consumption is imported, mainly from Russia, Algeria, and Norway. Germany in the largest consumer and importer of natural gas in the European Union.[4]

European countries are connected by extensive cross-border transmission pipeline networks. Liquefied natural gas (LNG) imports are transported by ship to terminals on the Mediterranean coast of Spain, France, and Italy; on the Atlantic coast of Spain; and on the North Sea coast of Belgium, where it is regassified and distributed to other EU countries via pipeline networks. Norwegian gas is transported to Belgium, France, and Germany, and from there to countries in Central and Southern Europe. Russian gas is transported through Austria and Germany to Western and Southern Europe. Pipelines also connect the gas fields in Algeria to Spain across the Strait of Gibraltar, and to Italy across the Mediterranean Sea.[5]

The European Commission adopted the Gas Directive (98/30/EC) in June 1998 with the objective of creating a single European natural gas market. The Directive, which entered into force in August 1998, required that Member States establish the implementing national laws, regulations, and institutions by August 2000.[6] The Directive provides common rules by which to govern the organization and operation of the natural gas sector in the European Union. The main features include introduction of competition, non-discriminatory rights to build new gas infrastructure facilities, fair and transparent access to the gas transportation and storage systems, and unbundling of internal accounts. The Directive also requires an independent agency to undertake regulatory functions.[7]

The Directive provides for a gradual opening of the EU gas retail market to competition over a ten-year period ending in 2008. It requires that final consumers be permitted to choose their gas supplier, and establishes a timetable for opening all market segments in three phases. The first phase allows power generators and other retail customers consuming more than 25 million cubic meters, or a minimum of 20 percent of the total gas market, to choose their gas suppliers by August 2000. Phase 2 extends market opening to all consumers of more than 15 million cubic meters per year, representing 28 percent of the gas market, by August 2003. The third phase offers choice to all consumers of more than 5 million cubic meters, or 33 percent of the market, by August 2008.[8]

The Directive offers Member States a choice between authorization or tendering procedures for the construction of network capacity. In the authorization procedure, the government simply approves proposals by private industry for the construction of new infrastructure, in accordance with published criteria. In the tender procedure, the government retains the role of planning for new capacity, and then publishes the construction details for tendering.[9]

The Directive's Third Party Access (TPA) provision mandates non-discriminatory access to the entire gas transportation system, including pipelines from production facilities to landing or processing terminals, terminals for importing and exporting LNG, high-pressure transmission pipelines, regional and local distribution pipelines, as well as storage, loading, and other ancillary facilities. While the Directive requires transparent and non-discriminatory TPA of facilities, the choice of terms of access is left to individual Member States. Terms of access may be regulated, negotiated, or a combination of both.[10] Regulated TPA consists of access to the transportation systems based on published tariffs and obligations that are approved by the government, whereas negotiated TPA lets companies negotiate access based on commercial conditions. In both cases, the directive requires some degree of separation, or unbundling, of gas marketing from transportation activities. The minimum level of unbundling is internal separation into independent business units, although countries may exceed this standard by requiring legal or ownership separation.

As of 2001, the Gas Directive had successfully met or exceeded some of its early objectives in terms of adoption by Member States and market opening, such that 80 percent of EU consumers may now choose their natural gas marketer. Nevertheless, industry representatives report that very little effective competition exists in the European Union and point to the fact that relatively few consumers have actually chosen to exercise their option to switch.[11]

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[1] A full text of the Directive can be found at Internet address *http://europa.eu.int/comm/energy/en/ gas_single_market/index_en.html*.

[2] Energy Information Administration (EIA), U.S. Department of Energy (DOE), "Regional Indicators: European Union (EU)," found at Internet address *http://www.eia.doe.gov/emeu/cabs/euro.html*, retrieved 8 Feb. 2001.

[3] D.V. Snieckus, "EC gas decontrol," *Oil & Gas Journal*, Tulsa, 1 Jan. 2001.

[4] The Brattle Group, Methodologies for Establishing National and Cross-Border Systems of Pricing of Access to the GAS System in Europe," Feb. 17, 2000, (London) p. 24

[5] IEA, OECD, "Natural Gas Transportation Organisation and Regulation," (OECD, Paris) 1994, pp.19-21.

[6] Greece and Portugal are exempt from opening provisions for up to 10 years due to their status as emerging markets. Consequently, implementation of the Directive in these two countries lags behind that of other Member States. Finland is also exempt because its pipeline network is unconnected to any other EU pipeline system, and has only one supplier. "Gas liberalisation in Europe," Petroleum Economist, London:2000, found at Internet address *http://proquest.umi.com/*, retrieved June 1, 2001.

[7] European Commission, " Opening up to Choice: Launching the Single European Gas Market," 2000.

[8] Ibid., p. 6.

[9] Andrew Allan, "More Sabre Rattling by the Commission," *Petroleum Economist*, London, Sep. 2000.

[10] "Opening up to Choice: Launching the Single European Gas Market," p. 9.

[11] Industry representative, telephone interview by USITC staff, May 10, 2001.

1997.[8] Repsol, which became Repsol-YPF following its 1999 acquisition of Argentine oil firm YPF, owns a substantial share of Spain's dominant natural gas firm, the Gas Natural Group (hereafter, Gas Natural).[9] The privatization of Enagás, an affiliate of Gas Natural which provides natural gas import, transmission, and regasification services, occurred in 1994.[10]

The National Energy Regulatory Commission (CNE) regulates both the electricity market and the natural gas market. The CNE, which is part of the Ministry of Economy, is an independent government entity.[11] The CNE's responsibilities include, among other things, ensuring transparency and competition in the gas market, proposing tariffs and other market provisions, and providing dispute settlement.[12] However, the Ministry of Economy is responsible for authorizing new facilities and approving tariffs.[13]

Industry Structure

Production and Imports

Gas Natural dominates all segments of Spain's natural gas market. Gas Natural is owned by the Spanish oil firm Repsol YPF (45 percent), Spanish bank La Caja de Ahorros y Pensiones de Barcelona (26 percent), and more than 20,000 additional shareholders.[14] Gas Natural comprises a number of entities, including Enagás (which it acquired in 1994), Gas Natural Internacional, Gas Natural Comercializadora, and Gas Natural Aprovisionamientos. Recent developments will likely have a significant impact on Gas Natural's market position. In June 2000, Spain established Royal Decree-Law 6/2000 in an effort to promote competition in the country's electricity, oil, and natural gas markets. Under this law, no industrial group is permitted to hold more than 35 percent of Enagás, and no operator will be permitted to supply more than 70 percent of the Spanish gas market after January 1, 2003.[15]

Natural gas accounted for 10 percent of Spain's energy consumption in 1998. Spain's indigenous supply of natural gas is extremely small and, thus, imports account for

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[8] Repsol YPF, "Repsol YPF," found at Internet address *http://www.repsol-ypf.com/*, retrieved May 3, 2001.

[9] U.S. Department of Energy (USDOE), Energy Information Administration (EIA), *Spain*, Jan. 2001, found at Internet address *http://www.eia.doe.gov/*, retrieved Apr. 30, 2001.

[10] OECD, "Promoting Competition in the Natural Gas Industry."

[11] CNE, *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*, Dec. 2000, found at Internet address *http://www.cne.es/*, retrieved Feb. 9, 2001.

[12] CNE, *Comisión Nacional de Energía (CNE)*, found at Internet address *http://www.cne.es/*, retrieved Apr. 12, 2001.

[13] European Commission, *State of Implementation of the EU Gas Directive (98/30/EC): An Overview*.

[14] Martin Quinlan, "Back in the Market for Gas," *Petroleum Economist*, Feb. 2000, found at Internet address *http://www.proquest.umi.com/*, retrieved Jan. 30, 2001.

[15] CNE, *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*; and Tom McBride, "Cross-Border Gas and Power Alliance," *Petroleum Economist*, Nov. 2000, found at Internet address *http://www,proquest.umi.com/*, retrieved May 3, 2001.

virtually all natural gas consumption.[16] Spain imports natural gas from Algeria and Norway via pipeline, and imports liquefied natural gas (LNG) from Algeria, Libya, Nigeria, Oman, Qatar, Trinidad and Tobago, and the United Arab Emirates.[17] In 1999, pipeline imports and LNG imports respectively accounted for 56 percent and 44 percent of Spain's total natural gas imports.[18] Currently, Enagás owns and operates all of Spain's import infrastructure, which includes a pipeline from France (through which Spain imports natural gas from Norway), the Pedro Duran Farell pipeline from Algeria, and LNG terminals located in Barcelona, Cartagena, and Huelva (figure 10-1).[19] A number of firms are planning to construct new import infrastructure in Spain. Spanish oil firm Cepsa and Algerian gas utility Sonatrach are considering the feasibility of a second gas pipeline between North Africa and Spain. The Reganosa group, comprising Sonatrach and seven Spanish firms, plans to construct a regasification terminal in Ferrol. The Bahia de Bizkaia Gas group – which includes BP, the Basque Energy Authority, Iberdrola, and Repsol YPF – also plans to build a regasification facility in northern Spain.[20]

Under the Hydrocarbons Act, transmission firms, retailers, and eligible customers are permitted to import gas, and Enagás is required to provide third-party access to its import infrastructure.[21] Although Enagás is currently Spain's primary natural gas importer, retail suppliers are beginning to secure supplies of imported gas. For example, Cepsa has imported LNG from Algeria.[22] Iberdrola will begin importing natural gas from Italian firm ENI in 2002, and Union Fenosa has established an agreement with the Egyptian Government to begin importing gas in 2005.[23] In addition, recent legislation requires Enagás to divest a portion of its contracted imports. Under Royal Decree-Law 6/2000, 25 percent of the contract between Enagás and Algerian gas utility Sonatrach, under which Sonatrach supplies natural gas to Spain through the Pedro Duran Farell pipeline, must be offered to between 4 and 10 retail suppliers during 2001, 2002, and 2003. These suppliers will be selected through a competitive bidding process.[24]

[16] USDOE, EIA, *Spain*.

[17] With the exception of France, Spain imports more LNG than any other European country. USDOE, EIA, *Spain*; USDOE, EIA, "World LNG Imports by Origin, 1999 (Billion Cubic Feet)," Sept. 25, 2000, found at Internet address *http://www.eia.doe.gov/*, retrieved Jan. 31, 2001.

[18] OECD, International Energy Agency (IEA), *Natural Gas Information*, 2000, p. IV.308.

[19] OECD, Promoting Competition in the Natural Gas Industry;" USDOE, EIA, *Spain*.

[20] USDOE, EIA, *Spain*.

[21] OECD, "Promoting Competition in the Natural Gas Industry."

[22] Martin Quinlan, "Back in the Market for Gas," *Petroleum Economist*.

[23] Tom McBride, "Cross-Border Gas and Power Alliance," *Petroleum Economist*.

[24] Tom McBride, "A Call for More Competition in the Gas Sector," *Petroleum Economist*, Aug. 2000, found at Internet address *http://www.proquest.umi.com/*, retrieved Jan. 30, 2001; and "Spain Starts to Share Out Long-Term Gas," *Gas Daily Europe*, May 1, 2001, found at Internet address *http://www.ft.com/*, retrieved May 2, 2001.

Figure 10-1
Natural gas pipelines in Spain

Source: Used with permission from the Organization for Economic Cooperation and Development, International Energy Agency. Maps obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition*.

Transmission and Distribution

Under Spain's Hydrocarbons Law, regasification, transmission, distribution, and storage are regulated activities and are subject to similar disciplines. Third-party access to facilities is guaranteed. Network access may be denied if a single provider would account for more than 60 percent of Spain's supply of natural gas as a result of such access.[25] Entities that secure administrative authorization may construct, modify, and/or operate transportation, storage, distribution, and regasification facilities.[26] However, under Royal Decree-Law 6/2000, the Spanish Government will not grant new authorizations for the construction of distribution networks in those regions in which distribution networks already exist until 2005.[27] Fees for transmission, storage, distribution, and regasification services are regulated through the establishment of maximum prices.[28]

Enagás is currently the dominant provider of natural gas transmission and storage services in Spain. Transmission and storage facilities owned by Enagás include a high-pressure pipeline network, which accounts for 84 percent of Spain's transmission infrastructure, and two underground facilities for strategic storage. Another company, Gas Euskadi, provides natural gas transmission services in Spain's Basque region.[29] Transmission firms are permitted to purchase gas that will be resold to distribution firms or to other transmission firms.[30]

Gas Natural is Spain's dominant natural gas distributor, accounting for 90 percent of that country's distribution market.[31] Gas Natural holds majority stakes in 11 natural gas distribution firms and minority stakes in three distribution firms.[32] However, in May 2000, Gas Natural agreed to float its distribution assets as a separate firm.[33] Under the Hydrocarbons Act, natural gas distributors are responsible for supplying gas to customers that are not eligible to choose their own supplier.[34] A distributor may purchase gas from its transmission provider in order to supply such customers.[35]

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[25] European Commission, *State of Implementation of the EU Gas Directive (98/30/EC): An Overview*, May 2000, found at Internet address *http://europa.eu.int/comm/energy/en/gas_single_market/index_en.html*, retrieved Jan 31, 2001.

[26] Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st edition, 1999, pp. 53-54, 58.

[27] CNE, *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*; Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st edition, 1999, pp. 103-104; and OECD, "Promoting Competition in the Natural Gas Industry."

[28] European Commission, *State of Implementation of the EU Gas Directive (98/30/EC): An Overview*.

[29] OECD, "Promoting Competition in the Natural Gas Industry."

[30] Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st. edition, 1999, p. 49.

[31] OECD, "Promoting Competition in the Natural Gas Industry."

[32] USDOE, EIA, *Spain*; and Tom McBride, "A Call for More Competition in the Gas Sector," *Petroleum Economist*.

[33] USDOE, EIA, *Spain*.

[34] Fernando Pombo and Ramon Novo, "Spain," *International Financial Law Review*, Oct. 1998, found at Internet address *http://proquest.umi.com/*, retrieved Jan. 31, 2001.

[35] Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st edition, 1999, p. 61.

Markets and Pricing

Spain's regulatory reforms eliminated the monopoly over the sale of natural gas to consumers and began the process of introducing competitive pricing for the commodity. Spain's transmission and distribution segments will continue to operate with regulated prices. The Hydrocarbons Act established a timetable for the opening of Spain's natural gas market to consumer choice.[36] In keeping with the most recent schedule, which was established on June 23, 2000, consumers of at least 3 million cubic meters per year are eligible to choose their gas marketer. Such consumers account for approximately 73 percent of the market. Beginning in January 2002, consumers of at least 1 million cubic meters per year, representing approximately 79 percent of the market, will be able to choose their own marketer. Consumer choice will be extended to all customers in January 2003.[37]

Consumers who are able to choose their own gas marketer, or eligible customers, are permitted to import gas and to purchase gas through bilateral contracts with marketers. Eligible customers and marketers are free to determine the prices and conditions under which these transactions take place. For a period of 3 years after gaining eligibility, customers also may purchase natural gas from distributors at regulated prices.[38] Ineligible customers continue to purchase natural gas from their local distribution company (LDC) at regulated prices.

Marketers source their gas by entering into bilateral contracts at unregulated prices with producers and importers; portions of these contracts may subsequently be resold to other marketers through an informal over-the-counter market.[39] In order to participate as a marketer, a firm must secure administrative authorization and maintain a 35-day supply[40] of natural gas in reserve.[41] As of May 2001, Spain had granted marketing licenses to approximately 20 firms, including Spanish oil firm Cepsa; Spanish electricity firms Endesa, Hidrocantabrico, Iberdrola, and Union Fenosa; French firms TotalFinaElf and Gaz de France; Italian energy firm ENI; British firm BP; British- and Dutch-owned Shell; and U.S. firm Enron.[42] Although marketers currently account for a small percentage of total gas sales, these firms have begun to capture market share from dominant Gas Natural. For example, BP, Endesa, and Shell supply natural gas to a total of 80 former clients of Gas Natural. Together, these clients account for 9 percent of the Spanish natural gas market.[43]

The effect of regulatory reform on gas prices is unclear.[44] Gas prices in Spain decreased in

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[36] CNE, *National Energy Regulatory Commission (CNE) Cronology, 1998-2000*.

[37] Ibid., and CNE, "Clasificación/Tipos de Consumidores," found at Internet address *http://www.cne.es/*, retrieved June 4, 2001.

[38] Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st edition, 1999, p. 100.

[39] Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st edition, 1999, p. 49.

[40] Based on company sales.

[41] Hydrocarbons Act 34/1998 (Unofficial English Translation), 1st edition, 1999, p. 63-64, 73.

[42] "Spain Starts to Share Out Long-Term Gas," *Gas Daily Europe*, May 1, 2001, found at Internet address *http://www.ft.com/*, retrieved May 2, 2001; and Martin Quinlan, "Back in the Market for Gas," *Petroleum Economist*.

[43] "Competition Builds in Spain," *Gas Daily Europe*, Mar. 5, 2001, found at Internet address *http://www.ft.com/*, retrieved Mar. 6, 2001.

[44] Commission of the European Communities, "Completing the Internal Energy Market," Commission Staff Working Paper, Mar. 12, 2001.

1999, declining by 6.5 percent for electricity generators, 4.6 percent for industry, and 9.8 percent for households.[45] Reportedly, these decreases were followed by a significant increase in Spanish natural gas prices between January and July of 2000. However, these trends likely reflect fluctuations in the price of crude oil[46] and in the value of the euro relative to the U.S. dollar, so they reveal little concerning the impact of regulatory reform.[47] Fluctuations in the exchange rate of the U.S. dollar and the euro likely impact European gas prices because gas and oil are priced in U.S. dollars in the international market, and because countries that have adopted the euro (with the exception of the Netherlands) are heavily dependent on imports.[48]

Impediments to Competitive Market Development

The principal impediment to competitive market development in Spain is the dominant position of Gas Natural. Gas Natural reportedly continues to supply 85 percent of Spain's natural gas, despite a 7-percent decline in market share in February 2001.[49] Gas Natural also continues to be the dominant supplier of transmission, storage, distribution, and regasification services, and marketers contend that the tariffs charged for such services are too high.[50] However, despite Gas Natural's current position, Spain's natural gas market is becoming more competitive. As discussed above, marketers are beginning to capture market share and recent legislation requires Gas Natural to reduce its infrastructure holdings. Under Royal Decree-Law 6/2000, Spain will eliminate the restriction on the construction of new distribution facilities in 2005, 3 years earlier than originally planned.[51] Spain also has demonstrated a willingness to discourage anticompetitive market arrangements. For example, in an effort to ensure that Spain's electricity generators receive equal treatment from Spain's dominant gas supplier, thus protecting the Spanish electricity sector from market distortions, Spain modified a supply agreement between Gas Natural and an electricity firm, in an effort to prevent the dominant Gas Natural from discriminating against other electricity firms. In addition, Gas Natural and Endesa, Spain's largest electricity firm, were denied authorization for a joint acquisition of two gas distribution establishments.[52]

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[45] USDOE, EIA, "Natural Gas Prices for Electricity Generation," "Natural Gas Prices for Industry," and "Natural Gas Prices for Households," Mar. 6, 2001, found at Internet address *http://www.eia.doe.gov/,* retrieved May 4, 2001.

[46] In many continental European countries, gas prices continue to be linked to the price of oil due to a lack of competition between gas suppliers.

[47] Commission of the European Communities, "Completing the Internal Energy Market," Commission Staff Working Paper, Mar. 12, 2001.

[48] USDOE, EIA, table 4.2 "World Dry Natural Gas Supply and Disposition," 1997, found at Internet Address *http://www.eia.doe.gov/,* retrieved Jan. 31, 2001.

[49] "Competition Builds in Spain," *Gas Daily Europe*.

[50] Martin Quinlan, "Back in the Market for Gas," *Petroleum Economist*.

[51] CNE, *National Energy Regulatory Commission (CNE) Chronology, 1998-2000*.

[52] OECD, "Promoting Competition in the Natural Gas Industry."

Spain does not appear to maintain any significant impediments to foreign participation in its natural gas sector. In general, Spain permits 100-percent foreign equity participation and grants equal legal treatment to Spanish and foreign firms. Spanish and foreign firms have equal access to incentives granted by the EU, national, regional, and local governments. Additionally, foreign buyers that participate in privatization processes receive the same treatment as their Spanish counterparts.[53]

[53] U.S. Department of Commerce, *FY 2001 Country Commercial Guide: Spain*, July 2000, found at Internet address *http://www.stat-usa.gov/*, retrieved May 9, 2001.

CHAPTER 11
THE UNITED KINGDOM

Overview

Regulatory reform in the United Kingdom reflects a series of policy initiatives that have evolved over time to address new objectives and problems as they arise.[1] The Oil and Gas Act of 1982 (Enterprise Act) introduced liberalization into the gas market in the United Kingdom by terminating the effective monopoly held by state-owned British Gas over the procurement of natural gas supplies and permitting large industrial users to buy gas from other suppliers.[2] However, because no new suppliers entered the market, British Gas remained the de facto monopoly. The Enterprise Act was followed by the Natural Gas Act in 1986, which created an independent regulator (the Director General of Gas Supply - DGGS), mandated the privatization of British Gas, which still held monopolies over natural gas transmission, distribution, and marketing to commercial and residential consumers, and required British Gas to provide open access to its transmission and distribution pipelines. Within the year, British Gas was privatized, removing all government participation in the British gas sector.[3] Additional steps were taken in 1993, when, acting on the recommendation of the Monopolies and Mergers Commission, British Gas internally segregated (unbundled) its gas production and marketing activities from its transportation and storage activities, making them separate business units.[4] The Gas Act of 1995 moved further to encourage competition by giving a stronger mandate to the regulatory agency and by revising the licensing framework to permit firms to acquire separate licenses for transport, shipping (wholesale marketing), and retail supply (retail marketing).[5] Consumer choice was progressively expanded in over the next 2 years, with all consumers in Great Britain becoming eligible to choose their natural gas supplier by 1998.

Meanwhile, for commercial reasons, British Gas divided itself into two independent companies in 1997: Centrica and BG plc. Centrica assumed the right to market gas in Great Britain under the brand name British Gas Trading (BGT) and acquired some of

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[1] Government representatives, interview by USITC staff, London, England, July 27, 2001.

[2] Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA), "Natural Gas Pricing in Competitive Markets," Dec. 1998, p. 129, found at Internet address *http://www.iea.org/pubs/studies/files/ngprice/ngprice.htm,* retrieved Feb. 28, 2001.

[3] U.S. Department of Energy (USDOE), Energy Information Agency (EIA), "Electricity Reform Abroad and U.S. Investment, Electricity's Relationship with U.K. Natural Gas Privatization," found at Internet address *http://www.eia.doe.gov/emeu/pgem/electric/ch2l6.html*, retrieved Feb. 27, 2001.

[4] OEDC, IEA, "Natural Gas Pricing in Competitive Markets."

[5] Energy Policy Directorate, Department of Trade and Industry (DTI), International and Energy Markets Branch, "Presentation on the U.K. Gas Supply Market," July 2001.

the gas production business. BG plc retained Transco, the pre-existing subsidiary that held the monopoly over national and regional transmission and local distribution. Transco was subsequently separated from BG plc in October 2000 and became a major part of the Lattice Group plc,[6] leaving BG plc with the international exploration, development, and marketing operations.

The independent regulatory agency continues to undergo structural changes as well. A Utilities Bill is presently before Parliament which proposes to formally combine the regulatory regimes for gas and electricity, replace individual regulators with an executive board or commission (the Gas and Electricity Markets Authority), clarify the principal responsibility of the Authority as protecting the interests of consumers, enable Ministers to give "Statutory Guidance" to the Authority on social and environmental objectives, and establish an independent statutory Gas and Electricity Consumer Council.[7] In the meantime, the gas and electricity market regulatory functions were combined in 1999 when the Director General of Gas Supply assumed the position of Director General of Electricity Supply and consolidated his offices into a single Office of Gas and Electricity Markets (OFGEM). Operating with a staff of approximately 150, OFGEM is responsible for enforcing the provisions in the Gas Acts of 1986 and 1995, for promoting competition in the gas industry, for enabling customers to make informed choices between suppliers, and for setting price controls and standards in areas of the industry where competition is not effective.[8]

Industry Structure

Production and Imports

The United Kingdom's natural gas reserves, estimated to be between 2,600 and 4,875 billion cubic meters, are located mostly in the North Sea off the English coast.[9] There is significant competition in the production of natural gas, and important gas fields are foreign owned, including BP Amoco's Leman, Chevron and Conoco's Brittania, and Shell's Indefatigable and Clipper.[10] Many other U.S. oil and gas production and

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[6] Transco, "What is Transco?," found at Internet address *http://www.transco.uk.com/,* retrieved Mar. 14, 2001.

[7] Energy Policy Directorate, DTI, International and Energy Markets Branch, "Presentation on the U.K. Gas Supply Market."

[8] Office of Gas and Electricity Markets (OFGEM), "Office of Gas and Electricity Markets Plan and Budget April 2000 - March 2001," Nov. 1999, found at Internet address *http://www.OFGEM.gov.uk,* retrieved Mar. 19, 2001.

[9] DTI, "Oil and Gas Resources of the United Kingdom 2000," found at Internet address *http://www.dbd-data.co.uk/bbonline/book.htm,* retrieved Mar. 8, 2001.

[10] USDOE, EIA, "Electricity Reform Abroad and U.S. Investment, Electricity's Relationship with UK Natural Gas Privatization," found at Internet address *http://www.eia.doe.gov/emeu/cabs/uk.html, retrieved Mar. 5, 2001.*

service companies are represented in the North Sea gas fields, including Amerada Hess, Arco, Baker Hughes, Enterprise Oil, ExxonMobil, Marathon, Phillips, Ranger Oil, Texaco, and Unocal.[11]

The vast majority of British natural gas production is domestically consumed. Of the estimated 105 billion cubic meters of natural gas produced in the United Kingdom in 1999, domestic suppliers purchased 90.9 billion cubic meters, a 5.2-percent increase from 1998. An additional 1.1 billion cubic meters of gas was imported, mainly from the Norwegian section of the Frigg field in the North Sea. Imports accounted for only 1.3 percent of the total gas supply in 1999, which represented an increase from 1 percent in 1998. The United Kingdom has traditionally been a net exporter of natural gas, but is expected to become a net importer as existing reserves become depleted. In 1999, a volume of 7.8 billion cubic meters, or 7.4 percent of production, was exported to the Netherlands from the Markham and Windermere fields, to Ireland from Scotland, and to Belgium via the Interconnector, a pipeline across the English Channel.[12]

Transmission and Distribution

An extensive offshore pipeline network connects the gas fields in the North Sea to receiving ports in Bacton, Theddlethorpe, Easington, and Teesside in England, and St. Fergus in Scotland (figure 11-1).[13] Offshore pipelines are owned and operated by oil and gas producing companies. The "Offshore Infrastructure Code of Practice," a voluntary code of practice adopted by industry participants in 1996, established a set of rules governing access to offshore pipelines. The main features of the Code of Practice are access to pipelines, disclosure of relevant information, and arbitration procedures. Third party access to offshore pipelines is negotiated on nondiscriminatory and fair market terms with the owners, who are not bound by any legal TPA obligation. However, the Ministry of Energy and Industry has the power to intervene if access is arbitrarily denied.[14]

Imports and exports of natural gas are shipped through pipelines connecting Great Britain to Ireland and Belgium. The Irish Gas Board (BGE) owns the pipeline which connects Ireland to the west coast of Scotland. The Interconnector is owned by an international consortium including BG plc (which has leased its capacity to British Gas Trading (BGT), BP Amoco, Conoco, Elf Aquitaine, Gazprom, National Power, Distrigaz, Ruhrgas, and Amerada Hess. The Interconnector pipeline is reversible, allowing for gas flows to and from the United Kingdom.[15]

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[11] DTI, Oil and Gas Supply Chain website, found at Internet address *http://www.dti.gov.uk/ogsc/supplyindex.htm*, retrieved Apr. 2, 2001.

[12] DTI, "Oil and Gas Resources of the United Kingdom 2000."

[13] USDOE, EIA, "North Field Fact Sheet," Feb. 2001, found at Internet address *http://www.eia.doe.gov/*, retrieved Apr. 2, 2001.

[14] OECD, IEA, "Natural Gas Distribution: Focus on Western Europe," Paris, 1998, p. 247

[15] OECD, IEA, "Natural Gas Pricing in Competitive Markets."

Figure 11-1
Natural gas pipelines in the United Kingdom

Source: Used with permission from the
Organization for Economic Cooperation and Development (OECD), International Energy Agency (IEA). Map obtained from OECD, IEA, Statistic Division, *Natural Gas Information–2000 Edition*.

Transco owns and operates the National Transmission System (NTS), which consists of the entire high-pressure transmission network and almost all distribution networks in Great Britain – over 265,000 km of pipelines. PowerGen, a power and gas company, owns a distribution line linking two power plants to an offshore receiving terminal on the east coast.[16] Some new independent public gas transporters (PGTs) are gradually entering the distribution market principally by constructing pipeline networks in new housing, commercial, and industrial developments.

Third party access to the onshore transportation and storage systems is guaranteed by a Network Code developed by Transco and other industry participants. The code, which came into effect in 1996, establishes standard terms and conditions of access to the NTS and Transco's storage facilities. Third party access to the NTS is based on published tariffs. Transco is responsible for correcting residual imbalances on the NTS, and also for ensuring that sufficient gas is available to meet the high demand in winter. It buys and stores gas in the amount of the difference between the volume of storage booked on the NTS and the estimated requirement.[17] The code allows Transco to interrupt delivery to sites that are declared interruptible under arrangement with gas suppliers. However, Transco may not discriminate between suppliers in deciding on interruptions.

Significantly, the Network Code also introduced a new transmission pricing regime which permits users of the pipeline network (shippers) to purchase entry and exit capacity separately as opposed to arranging for point-to-point transmission for each transaction. Transco's prices for transmission are separated into three elements: entry capacity, transportation commodity, and exit capacity.[18] The sum of these three elements can not exceed a price cap determined by OFGEM. However, the entry capacity price, and hence the allocation of pipeline capacity, is actually determined through an auction process. Transco holds entry capacity auctions every 6 months where marketers bid for firm and interruptible capacity in one-month increments. The transportation commodity price is dependent upon the revenues earned by Transco through the auctions, as the commodity price will be adjusted up or down in order to hold Transco's total transportation revenues to the price cap.[19] Finally, the exit capacity price reflects the long run marginal cost of expanding the transmission system to meet a sustained increase in demand within the particular exit zone. Any remaining

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[16] OFGEM, "How Gas Reaches Your Home," found at Internet address *http://www.ofgem.gov.uk/*, retrieved May25, 2001;and OECD, IEA, "Natural Gas Pricing in Competitive Markets."

[17] OECD, IEA, "Natural Gas Pricing in Competitive Markets."

[18] Transco, *Gas Transportation Charges from 1st June 2001*, pp. 2-8, found at Internet address *http://www.transco.uk.com.*

[19] In practice, entry capacity auctions have garnered far more money than anticipated, pushing the cost of the transportation commodity down to zero and still leaving Transco with a surplus beyond that permitted by OFGEM. This suggests that capacity may be constrained, particularly for gas entering the network at the St. Fergus entry point during summer months. While the excessive auction proceeds demonstrate how market mechanisms can effectively assign economic value to different segments of the transmission network and thereby identify system constraints, it also poses a problem of what to do with the extra money. U.S. industry and British Government representatives, interviews by USITC staff, London, England, July 26-7, 2001.

pipeline capacity that is not allocated through the one-month auctions is subsequently offered for sale by Transco through a daily auction market.

The new transmission pricing regime vastly facilitated transactions in physical and financial contracts and is credited with making a tradable market in natural gas possible.[20] Once gas enters the system, it becomes a standard commodity that may be traded by anyone, anywhere, regardless of where it originated. This essentially converted the transmission network into a single pool or trading hub where natural gas contracts are priced at a notional (not physical) location called the National Balancing Point.[21]

Natural gas storage services are provided predominantly by BG Storage, a subsidiary of BG plc. Storage facilities include the offshore Rough depleted field, a complex of salt caverns at Hornsea, and five LNG terminals.[22] In July 2001, BG plc announced plans to sell BG Storage to Dynegy (U.S.) For $590 million.[23] Other storage providers include Scottish Power and Aquila (U.S.). As an alternative to physical storage, Enron International (U.S.) has introduced a "virtual storage" service called EnBank. As with a physical storage facility, EnBank "receives" gas from customers when prices are low (typically in summer) and "delivers" it back to customers when prices are high (typically in winter). However, instead of placing the gas into a physical storage facility, Enron uses its portfolio of gas contracts to meet its obligations.[24]

Markets and Pricing

As a result of regulatory reforms, the price for natural gas in the United Kingdom is now determined by competitive markets, whereas transmission and distribution prices remain regulated. Licenses have been issued for marketing gas to industrial, commercial, and residential markets in competition with British Gas Trading. As of February 2000, 104 licenses had been issued for gas shipping, or wholesale marketing, and 93 licenses had been issued for gas supply, or retail marketing. Many firms hold both types of licenses. Licensees include independent energy marketing groups and companies set up by power generators, oil and gas producers, regional electricity suppliers, and marketing companies. Specific companies marketing natural gas in competition include Amerada Hess, British Fuels, Eastern Electricity, Total, Midlands

[20] U.S. industry representative, interview by USITC staff, London, England, July 26, 2001.

[21] ENRON Online, Market Info, "United Kingdom Natural Gas," found at Internet address http://www.enrononline.com, retrieved June 19, 2001.

[22] OECD, IEA, "Natural Gas Pricing in Competitive Markets."

[23] Andrew Taylor and Julie Earle, "Dynegy to Buy BG's Gas Storage Business,"*Financial Times,* found at Internet address *http://news.ft.com*, retrieved July 18, 2001.

[24] Industry representative, written response to questions submitted by USITC staff, May 2001.

Gas, Northern Electric, Norweb, Scottish Power, Southern Electric, Sterling Gas, SWEB Gas, SWALEC and Calortex.[25]

The competitive process for determining the price of natural gas entails interactions between producers, marketers, and consumers in a variety of settings, including a beach market, a spot market, and a futures market. Transactions may take place both through centralized exchanges and over-the-counter. In the beach market, offshore producers and bulk supply marketers trade gas with one another in order to meet their contractual obligations at the five landing terminals (the beach). For example, if a producer is unable to deliver the quantity of gas it had committed to at a particular terminal, it may purchase additional supplies from another producer. In the spot market, short-term contracts (less than 30 days) are purchased and sold both over-the-counter and through the International Petroleum Exchange (IPE). Many spot market transactions take place through Enron Online, an Internet-based service where Enron posts its purchase and sale prices for various contracts and executes transactions free of charge. Participants in the spot market include producers, marketers, large industrial consumers, and banks, as well as equity managers and speculators.[26] Spot market transactions for contracts of less than 24 hours take place in the On-the-day Commodity Market (OCM), a computer-based, over-the-counter exchange launched in October 1999 by OFGEM. The OCM, operated by EnMO, a joint venture between National Grid and Altra Energy Technologies (U.S.), permits producers and marketers to buy or sell gas to meet their daily balancing obligations.[27] Transco also trades gas on the OCM to correct residual imbalances and charges or compensates the users responsible at the average price paid on the OCM. Prices on the OCM can fluctuate widely as transaction volume remains relatively low.[28]

The futures market for natural gas was created in 1997 by the IPE to provide a transparent mechanism for hedging, speculation, and physical delivery of gas.[29] Standardized gas futures contracts trade in hourly, daily, monthly, quarterly, and semiannual increments for periods ranging from the day of the trade to 2 years.[30] Although trading on the IPE has steadily increased, futures trading volume is still smaller than the volume on the spot market.[31]

By participating in the daily, spot, and futures markets, marketers develop a portfolio of short, medium, and long-term wholesale supply contracts which they in turn use to enter into supply contracts with customers. These supply contracts also vary in terms and duration, although 1-year contracts, which tend to specify a fixed price, are the

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[25] OECD, IEA, "Energy Policies of IEA Countries: The United Kingdom 1998 Review," 1998, p. 81.

[26] ENRON Online, Market Info, "United Kingdom Natural Gas."

[27] OFGEM, "The New Gas Trading Arrangements: A decision document," p. 4, found at Internet address *http://www.ofgem.gov.uk/docs/ngtadec.pdf*, retrieved May 24,2001.

[28] OECD, IEA, "Natural Gas Pricing in Competitive Markets;" and Industry representative, written response to questions submitted by USITC staff, May 2001.

[29] OECD, IEA, "Natural Gas Pricing in Competitive Markets."

[30] ENRON Online, Market Info, "United Kingdom Natural Gas," retrieved Mar. 8, 2001; and OECD, IEA, "Natural Gas Pricing in Competitive Markets."

[31] OECD, IEA, "Natural Gas Pricing in Competitive Markets."

most common. Longer term contracts have escalation clauses with increases based on spot gas or oil price indices.

Since May 1998, licensed marketers have been allowed to sell gas to all classes of consumers in the United Kingdom at unregulated rates.[32] However, due to its dominant market share, prices charged by British Gas Trading to residential and small business consumers were regulated by OFGEM until 2001. By September 2000, approximately 5.7 million gas consumers, or 28.6 percent of the market, bought their gas from a company other than British Gas Trading, usually to realize a lower price.[33] End-user prices in the United Kingdom have declined significantly since liberalization of the gas market. The average price paid by large power generators dropped by 20 percent from 1990 to 2000. In 2000, industrial and commercial consumers paid on average 30 percent less in real terms compared to 1990, while prices paid by residential consumers decreased by 20 percent (24 percent if the value-added tax is excluded).[34]

Impediments to Competitive Market Development

The United Kingdom appears to have few if any significant impediments either to market development or international participation. Since British Gas Trading still controls over 60 percent of the market, there is some concern among industry representatives that ending the British Gas Trading price controls may pose competitive problems.[35] These representatives would prefer to see price controls continue to enable new market entrants to gain market share. With respect to international participation, the British market appears to be unrestricted. Representatives of foreign firms in the gas sector have not reported limitations on market access or national treatment.[36]

Although there do not appear to be any significant internal impediments to competitive market development in the United Kingdom, the slow pace of regulatory reform in Continental Europe may in fact have negative consequences for the British market.[37] Because large EU members like France and Germany have resisted implementation of the EU Gas Directive, prices for natural gas in Continental Europe continue to be

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[32] DTI, "Digest of Kingdom Energy Statistics 2000," London, 2000, found at Internet address *http://www.dti.gov.United Kingdom/EPA/digest.htm*, retrieved Mar. 7, 2001; and USDOE, EIA, "Electricity Reform Abroad and U.S. Investment, Electricity's Relationship with United Kingdom Natural Gas Privatization."

[33] OFGEM, "How Many People Are Changing Supplier," found at Internet address *http://www.ofgem.gov.uk/prices/switching.htm*, retrieved May 22,2001; and OFGEM, "A Review of the Development of Competition in the Domestic Gas Market," Oct. 1998, found at Internet address *http://www.ofgem.gov.uk/docs/areviewo.pdf*, retrieved May 24, 2001.

[34] "Gas liberalisation in Europe," *Petroleum Economist*, (London: 2000), found at Internet address *http://proquest.umi.com/*, retrieved June 1, 2001.

[35] Industry representative, written response to questions submitted by USITC staff, May 2001.

[36] Ibid.

[37] British Government representatives, interview by USITC staff, London, England, July 27, 2001.

indexed to oil prices rather than being competitively determined. With the completion of the Interconnector in 1998, the British gas market became physically linked to the Continental market for the first time in a major way (the capacity of the Interconnector is approximately 20 percent of total British demand), making it possible for British marketers to ship gas to the Continent. As a result, when oil prices increased sharply in 1999, gas prices on the Continent increased immediately as well.[38] Continental demand for less expensive British gas increased, driving up the market price for natural gas in the United Kingdom. Ultimately, after successfully delinking gas prices from oil prices through several years of market development, the British gas market became relinked to oil prices due to policies of neighboring countries.[39]

[38] Because natural gas is a substitute for oil to some extent, a rise in oil prices should lead some consumers to switch to gas, which in turn would increase demand for gas and, eventually, increase gas prices. However, the substitution effect on natural gas prices would not have been as significant or immediate as that resulting from indexing.

[39] British Government representatives, interview by USITC staff, London, England, July 27, 2001.

CHAPTER 12
SUMMARY AND CONCLUSION

As outlined in Chapter 2, the fundamental reason for pursuing regulatory reform is to achieve greater economic efficiency by introducing competition into segments where it is most feasible. Competition among private firms on the basis of price and service quality permits more efficient allocation of resources, as market price signals and consumer choice are believed to be more effective tools for matching supply and demand than regulatory instruments. Of the four distinct market segments in the natural gas industry, competition appears to be most feasible in the upstream production and downstream marketing segments, and least feasible in the midstream transmission and distribution segments, where natural gas monopoly conditions remain.

Once the decision is made to introduce competition, governments have a number of policy options that vary according to the existing industry structure and ultimate policy objectives. For example, privatization may or may not be necessary, depending upon the extent of private participation already present in the industry. Similarly, policies designed to foster retail competition may be of less immediate importance in countries with underdeveloped infrastructure, where it may be necessary to concentrate initially on encouraging private investment in the pipeline sector. In most cases, the development of these policies is an iterative process rather than a one-time event, as legislation and regulations must be adapted over time to address new factors that arise as the market evolves.

This chapter compares and contrasts the approaches to regulatory reform described in the preceding case studies. The chapter begins with a discussion of common elements of reform programs, which include the encouragement of private participation, the reorganization of industry structure, and the imposition of a third-party access regime. Next, the chapter addresses some indicators of the results of reform, which include the extent to which customer choice is permitted and exercised, and the extent to which trading markets have developed. The chapter will then address some of the impediments to competitive market development that have been identified before concluding with a discussion of the implications of regulatory reform for international trade in services.

Common Elements of Reform Programs

Private Participation

The countries reviewed in this report have pursued different policies concerning private participation depending upon their goals and the extent to which the government had formerly been engaged in the natural gas business. Canada and Japan have a long tradition of extensive private ownership in all market segments; thus policy reforms did not need to focus primarily on this question. The United Kingdom has a history of private participation in the production segment, but of government control in the transmission, distribution, and marketing segments. In Australia, the level of public versus private ownership varies by State. Argentina, Brazil, Korea, Mexico, and Spain all entered the reform process with the gas industry comprising a vertically integrated, government-owned monopoly.

Countries with government ownership of the natural gas industry had to choose whether and in which segments to introduce private participation. Argentina, Australia, Spain, and the United Kingdom have all pursued, and for the most part completed, extensive programs to shift ownership from public to private control. By contrast, Brazil and Mexico are constrained by constitutional provisions that do not permit private ownership in the upstream production segment. Nevertheless, both countries have privatized extensive portions of their downstream distribution segments. In Korea, planned reforms call for some privatization of the importing and transportation functions, whereas the city distribution companies were already privately owned.

As of now, all of the subject countries are pursuing policies that will permit private participation in the marketing segment, and all but those facing constitutional constraints are moving to permit private participation in the production and importing segment. Meanwhile, in the monopoly segments of transmission and distribution, all countries have similarly signaled movement toward private participation. This appears to be of particular importance for countries where the transmission and distribution pipeline infrastructure is underdeveloped, like Brazil and Mexico. Countries such as these will require considerable private investment in infrastructure development in order to support the growth of a competitive market for natural gas.

Industry Structure Reform

In addition to reforms that make private participation possible, most countries have also found it necessary to implement reforms to alter the industry structure. Often called unbundling, structural reform involves breaking up dominant industry participants to limit the potential for abuse of market power. Vertical restructuring entails breaking up a vertically integrated firm into separate production, transmission, distribution, and marketing components. The intent behind such restructuring is to ensure that a firm cannot exploit its monopoly role in transmission and/or distribution to cross-subsidize or otherwise favor an affiliate engaged in a competitive segment like marketing or production.

Vertical restructuring may be implemented by requiring separate accounts for each activity, requiring legal separation through a holding company structure, or, most definitively, by requiring full ownership separation. Of the subject countries, all but Brazil, Japan, and Korea have implemented vertical restructuring by requiring at least accounting separation. The absence of vertical restructuring in these three countries likely reflects the fact that each one is still in the relatively early stages of formulating its regulatory reform program. Argentina, Canada, and the United

Kingdom appear to have taken vertical restructuring furthest by requiring complete ownership separation in some situations.

In many cases, horizontal restructuring may also be necessary. Horizontal restructuring involves breaking up a firm that dominates a competitive market segment into smaller components that compete on a more equal footing with one another and new market entrants. This may be accomplished by selling portions of a firm during privatization, as Korea is considering; by auctioning concessions for some of the assets of the dominant firm, as Brazil is attempting in the production segment; or by other legal or regulatory action.

Third-Party Access

Third-party access represents the third prerequisite of a competitive market model. Once private participation is possible and the market power of dominant firms has been constrained, the natural gas market is confronted in most cases with the existence of a single pipeline network which must somehow be shared by multiple competing firms. In many cases, various portions of the network are actually owned by different companies. The government must therefore ensure that access and use of this common infrastructure is open on a nondiscriminatory basis to all competitors. In addition, the government sometimes has an interest in encouraging private firms to construct new pipeline capacity, in which case it is important to ensure that new entrants may tap into the existing network.

Implementation of a third-party access regime is accomplished by developing rules that afford access by all market participants to all essential infrastructure used in the provision of services to the general public.[1] These rules essentially require the owner of the facility to permit others to gain access at reasonable rates and through fair and transparent procedures. All of the subject countries have imposed third-party access requirements except Korea, which is still formulating its policy. In many cases, the government actively intervenes and regulates the rates that may be charged for transmission and distribution services. However, an alternative approach is to permit transmission and distribution providers to negotiate with those who would like to use their facility, subject to retrospective oversight by the government. The negotiated access approach, which has been adopted in Argentina, Brazil, Canada,[2] and Mexico, may afford somewhat less transparency than the regulated price approach.

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[1] Pipelines constructed for private use are exempted, as these do not serve the public at large.

[2] Canada permits negotiated access for transmission only; distribution prices are regulated.

Indicators of Reform Results

Customer Choice

The most visible indicator of reform results is the extent to which purchasers of natural gas may choose their marketer. In virtually all cases, reform programs have been phased in by first permitting marketers, who may be producers, distribution companies, or pure intermediaries, to compete to sell to only large industrial consumers and other marketers in the initial stages. This may be called the introduction of competition at the bulk or wholesale level. Over time, competition is extended to progressively smaller consumers until ultimately all consumers are permitted to choose their marketer. With the exception of Brazil and Korea, where policies permitting choice are planned but have yet to be implemented, the reforms undertaken by all of the subject countries permit customer choice at the bulk or wholesale level (table 12-1). Argentina, Japan, Mexico, and Spain have limited the sphere of competition by maintaining a minimum consumption threshold before customer choice is permitted, ranging from 1 to 3 million cubic meters per year. Australia, Canada, and the United Kingdom have gone further by extending competition and customer choice to all classes of consumers.

Although the extent of consumer choice that is potentially possible presents a useful yardstick for comparing reform programs, it may not be an effective indicator of the extent to which competition is actually taking place. The fact that customers may legally choose a different marketer does not necessarily mean that they have sufficient incentives to exercise that choice, or that other factors are not impeding their options. Alternatively, consumers may not need to physically switch to a competing service provider in order to benefit from competition, as the mere potential for such a switch may compel their existing service provider to reduce prices. Consequently, more detailed information addressing multiple competitive indicators would be necessary in order to truly assess whether consumers have effective choice among credible competitors. Such indicators could include the number of consumers who have switched marketers, the market share of major participants, and the number of new entrants to the market.[3] This information is difficult to collect on a systematic basis. Of the subject countries, information on the extent to which consumers are switching marketers is available only for Argentina and the United Kingdom. In Argentina, approximately 32 percent of total gas sales were negotiated with marketers other than the local distribution company by 1997, five years into the reform program.[4] In the United Kingdom 32 percent of

[3] OXERA, a U.K.- based research group, has collected and analyzed detailed market information for the electricity and natural gas industries in Europe in order to develop a set of "liberalization indicators." Thus far, however, OXERA has been able to develop natural gas liberalization indicators only for the United Kingdom and the Netherlands. On the basis of these indicators, the British gas market is considerably more liberal than that of the Netherlands. OXERA, *Energy Liberalization Indicators in Europe*, May 2000, p. 16.

[4] OECD, IEA, *Regulatory Reform in Argentina's Natural Gas Sector*, p. 53.

Table 12-1
Status of customer choice, by country

Country	Extent of customer choice
Argentina	Demand greater than 10,000 cubic meters per day
Australia	All customers (by July 1, 2002, in Western Australia)
Brazil	Large industrial users, power plants, and distribution companies may choose to import directly
Canada	All customers
Japan	Demand greater than 1 million cubic meters per year
Mexico	Large industrial users, power plants, and distribution companies may choose to import directly
South Korea	No effective choice
Spain	Demand greater than 3 million cubic meters per year
United Kingdom	All customers

Source: Compiled by the Commission.

Consumers had switched as of June 30, 2001, three years after consumer choice was extended to all customers.[5]

Trading Market Development

Another indicator of how well reform programs have succeeded in fostering a competitive market is the extent to which trading markets have developed. As observed in Chapter 2, markets for trading natural gas and transportation contracts emerge once a competitive regulatory framework is in place. In the natural gas market, participants trade natural gas as a commodity, whereas in the transportation market, participants trade transportation services in the form of pipeline capacity contracts. These markets may be informal, consisting of bilateral transactions negotiated privately, or centralized, in which case standardized contracts are traded on a centralized exchange.

Among the subject countries, formal trading markets have evolved to an advanced degree only in Canada and the United Kingdom. In Australia, centralized exchanges for gas and transportation capacity have been formed only in the state of Victoria, and futures contracts have yet to develop. Canadian firms trade gas contracts at trading hubs that have evolved in Alberta and various locations within the United States and may also trade futures contract on the New York Mercantile Exchange. In

[5] As noted in Chapter 11, all consumers became eligible to switch suppliers in 1998. OFGEM, "How Many People are Changing Supplier," found at Internet address *http://www.ofgem.gov.uk*, retrieved May 22, 2001.

the United Kingdom, trading markets are highly developed and include centralized exchanges for gas, gas futures, and pipeline capacity.

Significant trading activity does not appear to be taking place in any of the remaining countries. Korea and Brazil have yet to fully implement the reforms necessary to make trading possible. Trading is deterred in Japan in part because of incomplete implementation, but more significantly as a result of infrastructure constraints that prevent interconnection between different regions. In Mexico and Spain, trading is theoretically possible and may well be taking place informally, but the volume of transactions is believed to be small.

Price and Service Availability

Since regulatory reform is intended to enhance economic efficiency and social welfare, one would expect that countries that have made the transition to private, competitive markets have lower prices and better service availability than they would have had with a fully regulated or government-controlled industry. Unfortunately, developing objective indicators of price and availability is extremely difficult to do for a single country, let alone for a group of countries at different stages of reform such as those examined in this study. While price trend data generally are available, in-depth econometric analysis would be necessary to make an attempt at discerning the extent to which price variations are a result of regulatory policy or other factors. For example, natural gas prices may be influenced by weather patterns, the pricing of alternative fuels like oil, or policy decisions concerning the environment. Determining the extent to which the introduction of competition has influenced prices as opposed to such other factors is a challenge that lies beyond the scope of this study, and such research has yet to be performed by any other groups concerning the subject countries.[6]

Nevertheless, some anecdotal information is available for a few of the countries examined in this report. For example, in the State of Victoria, Australia, where there is competition among marketers but limited competition among upstream producers, natural gas prices have declined by the relatively modest rates of 2 percent, 4 percent, and 7 percent for the industrial, commercial, and residential segments, respectively.[7] In the city of Sao Paulo, Brazil, where only privatization has taken place, natural gas sales have increased by 70 percent since private investors gained control and subsequently expanded the distribution network.[8] In the United Kingdom, where competitive markets are highly advanced, nearly 60 firms have entered the marketing segment by obtaining supply licenses and the average price in real terms paid by

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[6] Some econometric analysis of these factors has been performed by Paul. W. MacAvoy of Yale University. His analysis of U.S. regulatory reform finds that considerable gains accrue to all stakeholders as a result of deregulation. Paul W. MacAvoy, *The Natural Gas Market*, p. 120.

[7] Australian Gas Association, "Implications of downstream reform for the upstream sector," speech by Alan Beasley, Deputy Chief Executive, Oct. 1998, found at Internet address *http://www.asn.org.au*, retrieved Jan. 31, 2001.

[8] Brazilian industry representative, interview by USITC staff, Sao Paulo, Brazil, May 9, 2001.

industrial, commercial, and residential consumers declined by 20 percent, 30 percent, and 20 percent, respectively, from 1990 to 2000.[9]

Impediments to Competitive Market Development

Although several countries have made considerable progress toward introducing competition into the natural gas industry, a number of impediments remain. As noted, liberalization of natural gas markets is being pursued through three pillars of reform: the introduction of private-sector participation; the implementation of structural reform, including vertical and horizontal unbundling; and the development of an open, or third-party access system, to pipeline networks and other natural gas facilities. Failure to address any one of these aspects can present a significant impediment to new market entrants and thus stifle competition.

In practice, it appears as though regulatory reform programs have the greatest difficulty in bringing about effective structural reform and in guaranteeing third-party access. Problems related to inadequate horizontal restructuring have also arisen in both the production and marketing segments. In Brazil, Korea, Mexico, and Spain, a single firm continues to control virtually all sources of supply and holds a dominant share of the marketing segment. Even in Argentina and the United Kingdom, where market competition is relatively advanced, the incumbent marketing service provider continues to hold over 60 percent of market share. Problems have also arisen with respect to vertical restructuring. Brazil, Korea, and Japan have yet to implement policies requiring separation of monopoly functions from competitive activities, while relatively few countries – Argentina, Canada, and the United Kingdom – have imposed the strongest form of unbundling, ownership separation. These factors have contributed to ongoing concerns that potential cross-subsidization and abuse of market power by incumbent service providers may deter new market entrants and so impede competition.

With respect to guaranteeing third-party access, the principal problems appear to concern the transparency and effectiveness of access rules. For example, rules governing third-party access are reportedly unclear in Brazil, while in Japan, the manner in which gas utilities calculate third-party access rates is reportedly nontransparent, which may deter new users from trying to access the pipeline network. In addition, Japan's third-party access regime does not include coverage of LNG terminals and storage facilities, which may be significant given that the country relies almost exclusively on imported LNG to meet its natural gas needs.

In addition to the above difficulties in implementing regulatory reform, physical constraints may also present impediments to competitive market development. In four of the subject countries – Australia, Brazil, Japan, and Mexico – the pipeline infrastructure is reportedly either inadequate or lacking sufficient excess capacity to support competition. In Brazil and Japan, pipeline networks do not extend outside of

[9] "Gas liberalization in Europe," *Petroleum Economist*, London: 2000, found at Internet address *http://proquest.umi.com*, retrieved June 1, 2001.

major urban areas. Japan, like Australia, also lacks interconnection between pipeline networks which serve regional markets. The lack of pipeline infrastructure fragments markets regionally and prevents effective, nationwide competition. In addition, Australia, Japan, and Mexico have a limited amount of excess capacity in natural gas pipelines, LNG terminal facilities, or both. This means most of the existing capacity has already been contracted, making it difficult for new entrants to purchase capacity.

Finally, the duration of current long-term take-or-pay supply contracts may impede the transition to a competitive market. In countries like Japan and Korea, which have extensive long-term supply contracts for LNG, such contracts essentially crowd out new entrants.

One interesting aspect of the impediments identified by industry representatives is that there are relatively few that are directed specifically at foreign firms. Of the nine subject countries examined in this study, only Korea maintains a clear market access restriction: a ceiling on foreign equity ownership in newly privatized subsidiaries of the monopoly gas utility. The general uniformity of treatment between foreign and domestic firms may be explained by the fact that regulatory reform programs are essentially intended to facilitate entry by any and all potential new market participants. In some cases, investment from foreign firms may even be an essential element to support competitive market development. Consequently, imposing impediments selectively on foreign firms would appear to be counterproductive.

Implications for International Trade in Services

The natural gas industry is becoming increasingly global. Pipeline networks are expanding across all continents and even extending undersea. Liquefied natural gas is increasingly competitive with gas provided by pipeline, making it practical to bring natural gas reserves from remote locations to new markets. Price changes in one market may influence pricing around the world. For example, the price increase experienced during the winter of 2000-2001 in North America was felt in the United Kingdom as producers diverted shipments of LNG to serve the more profitable U.S. market. Similarly, oil price increases in continental Europe, where gas prices remain regulated and linked to oil prices, resulted in higher prices for natural gas in the United Kingdom.[10] Meanwhile, advances in gas turbine technology and environmental concerns over greenhouse gas emissions have made natural gas the fuel of choice for new power plants, thereby creating a new class of consumers and substantially increasing global demand. These factors have led to a convergence of interests among producers, consumers, and governments to increase access to low-cost natural gas as a means of diversifying energy sources, enhancing consumer welfare, and supporting industrial competitiveness. In pursuit of these goals, regulatory reform is increasingly seen as an effective policy approach.

[10] British Government representatives, interview by USITC staff, London, England, July 27, 2001.

As the global market for natural gas expands and regulatory reform extends to a broader range of countries, some clear implications emerge for international trade in both goods and services. Growth in global demand for natural gas leads to increased trade in the commodity as well as in all of the merchandise related to its transportation and consumption. With respect to services, regulatory reform creates new opportunities for private firms to invest internationally in the natural gas transmission, distribution, and marketing sectors. In regions where natural gas markets transcend national frontiers, such as Europe, South America, and North America, private firms may also have new opportunities to provide marketing, risk management, and related services on a cross-border basis. In trade terms, these new business prospects constitute new market access opportunities, which means that regulatory reform directly fosters growth of international trade in services.

Since regulatory reform affects international trade in services, it appears logical to consider the relationship between reform and international trade agreements. The most relevant agreement appears to be the General Agreement on Trade in Services (GATS) of the World Trade Organization (WTO). When the GATS entered into effect in 1995, it included a built-in agenda to pursue progressive rounds of liberalization. In accordance with this provision, WTO members initiated a new round of GATS negotiations on January 1, 2000, with the objective of expanding trade and thereby promoting global economic growth.[11] However, because regulatory reform represents a major domestic policy initiative, the extent to which an international agreement can drive the process may be limited. Consequently, WTO members are unlikely to use trade instruments like the GATS to promote regulatory reform in other countries. In fact, the European Commission has formally stated that it does not wish to pursue deregulation through trade negotiations.[12]

The GATS may, however, be an effective instrument for supporting reform programs after they have been implemented. As noted above, regulatory reform programs essentially facilitate market entry by any and all potential participants. More participants and more diverse sources of investment result in stronger competition and higher quality, lower cost services. Consequently, the optimal pool of potential new entrants is as large as possible and includes foreign participation. But foreign firms often face increased risk when operating internationally, as indigenous firms may have better access to and influence over the local regulatory, political, and judicial systems. International commitments to a set of principles concerning foreign participation, such as those contained in the GATS, can help mitigate this risk by providing assurance that foreign firms will be treated in a nondiscriminatory manner. In addition, recourse to the WTO dispute settlement mechanism may afford greater credibility to the reform programs and regulatory authorities of countries that undertake commitments pertaining to natural gas services.

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[11] World Trade Organization, *General Agreement on Trade in Services and Related Instruments*, Apr. 1994, p. 3.

[12] World Trade Organization, “Communication from the European Communities and their Member States, GATS 2000: Energy Services,” submitted to the Council for Trade in Services, Special Session, document No. S/CSS/W/60, Mar. 22, 2001.

WTO members have already made some commitments under the GATS that are relevant to natural gas services. These commitments may be divided into two categories: *framework commitments* and *specific commitments*. *Framework commitments* apply to virtually all possible service sectors[13] and include obligations concerning most-favored-nation treatment, transparency, domestic regulation, and monopolies and exclusive suppliers (table 12-2). *Specific commitments* apply only to specific service sectors that are explicitly named by each country in its "Schedule of Specific Commitments." In scheduling commitments on market access and national treatment for specific service activities, WTO members worked from a list of service sectors prepared by the Secretariat (identified by its document number: MTN.GNS/W/120) which included cross references to industry definitions contained in the United Nations Provisional Central Product Classification (CPC). The specific commitments include obligations concerning market access and national treatment.

However, two important open questions concerning the scope of existing GATS commitments create considerable uncertainty for both businesses and governments. First, the existing industry classification may not permit countries to make meaningful commitments on natural gas services in their Schedules of Specific Commitments. U.S. industry representatives have expressed concern that, because energy services are ill-defined by the industry classification system, it is unclear as to whether specific commitments to accord market access and national treatment apply to their activities.[14] Indeed, the classification system makes only oblique reference to the natural gas industry in two categories: "Services Incidental to Energy Distribution," a subcategory of "Other Business Services," and "Pipeline Transportation of Fuels," a subcategory of "Transportation Services." Trading and marketing of natural gas are not explicitly mentioned anywhere in the classification. It is therefore unclear if marketing of natural gas is simply a wholesale or retail distribution service or a unique energy service. If it is a distribution service, then specific commitments made by countries on distribution services automatically extend to natural gas marketing, unless gas marketing is explicitly exempted. By contrast, if WTO members agree that natural gas marketing is a new energy service, then countries would need to make new commitments specifically for this industry category. In any case, it presently is not clear where natural gas services are classified, which means that industry representatives are not sure whether Commitments made by WTO members do indeed apply to their activities, and governments are not sure of the full scope of commitments they have already undertaken.

The second open question concerns whether existing obligations provide sufficient guarantees of *effective* market access for the natural gas industry. The GATS market access discipline is narrowly defined to include only six types of restrictions, most of which pertain to quantitative limitations (table 12-2). Policies that restrict trade but are not included on this list are then permissible under the agreement. For example, a

[13] The sole exception is air transport services.

[14] Rachel Thompson, "Integrating Energy Services into the World Trading System," Washington, DC, Apr. 10, 2000, p. 1.

Table 12-2
Selected GATS provisions

Market Access	The GATS market access principle, contained in Article XVI, establishes the objective of progressively eliminating a set of six specific types of limitations to market access. These are: a) limitations on the number of service suppliers whether in the form of numerical quotas, monopolies, exclusive service suppliers or the requirements of an economic needs test; b) limitations on the total value of service transactions or assets in the form of numerical quotas or the requirement of an economic needs test; c) limitations on the total number of service operations or on the total quantity of service output expressed in terms of designated numerical units in the form of quotas or the requirement of an economic needs test; d) limitations on the total number of natural persons that may be employed in a particular service sector or that a service supplier may employ and who are necessary for, and directly related to, the supply of a specific service in the form of numerical quotas or the requirement of an economic needs test; e) measures which restrict or require specific types of legal entity or joint venture through which a service supplier may supply a service; and f) limitations on the participation of foreign capital in terms of maximum percentage limit on foreign share-holding or the total value of individual or aggregate foreign investment.
Nondiscrimination	The GATS principles concerning nondiscrimination are contained in Articles II and XVII. Article II provides for most-favored-nation treatment (MFN), through which WTO members commit to accord to services and service suppliers of any other member treatment no less favorable than that accorded to like services and service suppliers of any other country. Members must adhere to MFN principles except in those areas in which they have listed exemptions. Article XVII provides for national treatment, which is described as treatment no less favorable than that accorded to domestic services and service suppliers. National treatment applies to the extent a member has committed to it on its schedule of specific commitments.
Transparency	GATS transparency obligations are contained in Article III, which requires: - Prompt publication of relevant measures of general application - Notification to the WTO of significant changes in laws, regulations, or administrative guidelines with significant bearing on services trade - Establishment of enquiry points for use by other WTO members - Prompt responses to information requests from other WTO members
Domestic Regulation	GATS domestic regulation obligations, as contained in Article VI, require WTO members to: - Avoid using regulatory powers in such a way as to create services trade barriers - Ensure that measures of general application are administered in a reasonable, objective, and impartial manner - For sectors in which specific commitments are undertaken regarding market access or national treatment, ensure that licensing and qualification requirements or technical standards (1) are based on objective and transparent criteria, (2) are not more burdensome than necessary, and (3) in the case of licensing procedures, are not in themselves a restriction on the supply of the service.
Monopolies and Exclusive Suppliers	Article VIII of the GATS asserts that WTO members should ensure that, in cases where a monopoly supplier competes in supplying a service outside the scope of its monopoly rights, such a supplier does not abuse its monopoly position in a manner that limits market access or national treatment.

Source: World Trade Organization, *General Agreement on Trade in Services.*

foreign firm may be granted market access and so be able to establish a natural gas trading and marketing affiliate, but then face impediments when trying to access the transmission network that foreclose effective access to the market. Further, the GATS framework disciplines concerning transparency and domestic regulation apply to "measures of general application," which means these rules may not apply to specific measures implemented by natural gas regulatory authorities. These factors may be of particular concern for natural gas services because of the importance of nondiscriminatory access to essential facilities (the public pipeline network) – GATS commitments may be impaired as a result of inadequate coverage of aspects concerning access to and use of common infrastructure facilities, or third-party access. However, the GATS offers the flexibility to negotiate additional rules concerning issues like third-party access which can be tailored to meet the specific needs of an industry, should WTO members agree that additional provisions are necessary. GATS negotiations concerning telecommunications have set a precedent for provisions such as these by developing additional rules on access and use of network facilities and by strengthening GATS framework rules on transparency and nondiscrimination as they apply to certain regulatory policies and practices.[15]

Conclusion

The countries examined in this study represent a diverse group. Some have considerable natural gas reserves, while others are dependent upon imports by pipeline, LNG tankers, or both. Some are comparatively wealthy with sufficient capital to finance infrastructure development, while others must focus on attracting foreign direct investment. Without question, these national variations have bearing on the nature of regulatory reform, as well as on the timing and extent of competitive market development.

Nevertheless, the reform programs undertaken by each of these countries are broadly compatible with one another and consistent with the general model for reform described in Chapter 2. These programs incorporate policies encouraging private participation, constraining the market power of incumbent firms, and guaranteeing nondiscriminatory access to essential facilities in order to create an environment conducive to new market entrants and vibrant competition. The result of reform can be seen in the expansion of customer choice and the development of trading markets for natural gas, transportation capacity, and related financial instruments.

While reform programs have generally succeeded in introducing competition into the most viable segments of the natural gas industry, some significant impediments remain. These include difficulties in controlling the market power of incumbent service

[15] GATS Article XVIII provides for the negotiation of additional commitments to address measures affecting trade in services that are not covered by the market access and national treatment provisions. As a result of negotiations on basic and value-added telecommunication services, additional commitments were appended to the GATS through two separate instruments: the Annex on Telecommunications and the Regulatory Reference Paper on basic telecommunications.

providers and problems in implementing effective, nondiscriminatory third-party access to pipelines. Despite these impediments, prevailing trends appear to suggest that the market for natural gas will continue to expand globally and that the competitive market model will be adopted by a progressively larger group of countries. As a consequence, international trade in natural gas services will likely continue to expand, leading to increased relevance for trade rules such as those contained in the GATS.

Appendix A
Request Letter

EXECUTIVE OFFICE OF THE PRESIDENT
THE UNITED STATES TRADE REPRESENTATIVE
WASHINGTON, D.C. 20508

JAN 11 2001

DOCKET NUMBER
2167
Office of the Secretary
Int'l Trade Commission

'01 JAN 16 ... 52

The Honorable Stephen Koplan
Chairman
U.S. International Trade Commission
500 E Street, SW
Washington, DC 20436

Dear Chairman Koplan:

As you are aware, beginning in January 2000, members of the World Trade Organization commenced a new round of services trade negotiations under the General Agreement on Trade in Services (GATS). These negotiations are intended to liberalize services trade by reducing or eliminating measures that limit effective market access.

With these negotiations in mind, I requested that the U.S. International Trade Commission initiate a series of reports on regulatory reform of foreign energy markets. Liberalization of energy markets could have a large beneficial impact on the global economy. The first report in this series, delivered in November 2000, examines developments in the electricity industry.

It now appears prudent to examine foreign natural gas markets. Like the electricity industry, the natural gas industry in many countries is evolving from a monopolistic into a competitive industry with increasing numbers and types of participants. As with electricity, countries have reformed their natural gas sectors largely by privatizing and unbundling state-owned assets, providing open access to transmission (pipeline) networks, and permitting competition in production, distribution, and supply services. In many cases, reforms have been undertaken with a view to fostering competition and attracting foreign investment. Consequently, regulatory reform of the natural gas sector is likely to have a significant impact on market access opportunities and the competitive position of U.S. firms.

Therefore, I request, pursuant to authority delegated by the President under section 332(g) of the Tariff Act of 1930, that the U.S. International Trade Commission conduct an investigation that (1) discusses the nature of reform, including, but not limited to the extent of privatization, vertical and horizontal restructuring, and consumer choice, as applicable; (2) examines current market access conditions, including, but not limited to measures affecting network access, investment and trading (i.e., the exchange of natural gas contracts on financial markets), as applicable; and (3) identifies common regulatory practices, insofar as they exist. I urge the Commission to focus the study on the downstream natural gas market, including the following segments: transmission (including transport and storage); distribution; wholesale and retail supply; and trading. In terms of geographic coverage, the Commission's report should examine countries where natural gas sectors are currently undergoing varied yet significant reform, including Australia, Argentina, Brazil, Canada, Korea, Japan, Mexico, Spain, and the United Kingdom.

The Commission is requested to deliver this report no later than nine months from receipt of this letter. This office intends to make the Commission's report available to the general public in its entirety. Therefore, the report should not contain any confidential business or national security classified information.

Upon completion of this report, it is the intent of this office to make a similar request for an investigation of the upstream oil and gas field services industry.

The Commission's assistance in this matter is greatly appreciated.

Sincerely,

Charlene Barshefsky

Appendix B
Federal Register Notice

INTERNATIONAL TRADE COMMISSION

[Investigation 332–426]

Natural Gas Services: Recent Reforms in Selected Markets

AGENCY: United States International Trade Commission.

ACTION: Institution of investigation.

EFFECTIVE DATE: February 8, 2001.

SUMMARY: Following receipt of a request on January 16, 2001, from the United States Trade Representative (USTR), the Commission instituted investigation No. 332–426, Natural Gas Services: Recent Reforms in Selected Markets, under section 332(g) of the Tariff Act of 1930 (19 U.S.C. 1332(g)).

FOR FURTHER INFORMATION CONTACT: Information specific to this investigation may be obtained from Mr. Christopher Melly, Project Leader (202–205–3461; cmelly@usitc.gov), Ms. Joann Tortorice, Deputy Project Leader (202–205–3032; jtortorice@usitc.gov), or Mr. Richard Brown, Chief, Services and Investment Division (202–205–3438; rbrown@usitc.gov), Office of Industries, U.S. International Trade Commission, Washington, DC, 20436. For information on the legal aspects of this investigation, contact William Gearhart of the Office of the General Counsel (202–205–3091; wgearhart@usitc.gov). Hearing impaired individuals are advised that information on this matter can be obtained by contacting the TDD terminal on (202) 205–1810.

Background

In a letter dated January 16, 2001, the USTR requested that the Commission, pursuant to section 332(g) of the Tariff Act of 1930, conduct an investigation of the natural gas services markets in countries where significant market reform, privatization, and liberalization has occurred or is ongoing. The foreign markets to be examined are: Argentina, Australia, Brazil, Canada, Korea, Japan, Mexico, Spain, and the United Kingdom. As requested, in its report, the Commission will (1) describe the nature of reform, including, but not limited to the extent of privatization, vertical and horizontal restructuring, and consumer choice, as applicable; (2) examine current market access conditions, including, but not limited to measures affecting network access, investment, and trading (i.e., the exchange of natural gas contracts through financial markets), as applicable; and (3) identify common regulatory practices adopted by multiple countries, insofar as they exist. For the purpose of this study, natural gas services will focus on the downstream natural gas market, including the following segments: transmission (including transport and storage); distribution; wholesale and retail supply; and trading.

This letter follows a similar request made by the USTR in November 1999 for the Commission to conduct an investigation of the electric power services markets in Argentina, Australia, Brazil, Canada, Chile, the European Union, Japan, New Zealand, and Venezuela. The Commission submitted its report to the USTR on November 23, 2000, copies of which may be obtained by contacting the Office of the Secretary at 202–205–2000 or by accessing the USITC Internet server (http://www.usitc.gov). The USTR asked that the Commission furnish the natural gas report by October 16, 2001, and that the Commission make the report available to the public in its entirety.

Public Hearing

A public hearing in connection with the investigation will be held at the U.S. International Trade Commission Building, 500 E Street SW, Washington, DC, beginning at 9:30 a.m. on April 3, 2001. All persons shall have the right to appear, by counsel or in person, to present information and to be heard. Requests to appear at the public hearing should be filed with the Secretary, United States International Trade Commission, 500 E Street SW, Washington, DC 20436, no later than 5:15 p.m., March 20, 2001. Any prehearing briefs (original and 14 copies) should be filed not later than 5:15 p.m., March 22, 2001; the deadline for filing post-hearing briefs or statements is 5:15 p.m., April 25, 2001. In the event that, as of the close of business on March 20, 2001, no witnesses are scheduled to appear at the hearing, the hearing will be canceled. Any person interested in attending the hearing as an observer or non-participant may call the Secretary of the Commission (202–205–1806) after March 20, 2001, to determine whether the hearing will be held.

Written Submissions

In lieu of or in addition to participating in the hearing, interested parties are invited to submit written statements (original and 14 copies) concerning the matters to be addressed by the Commission in its report on this investigation. Commercial or financial information that a submitter desires the Commission to treat as confidential must be submitted on separate sheets of paper, each clearly marked ‘‘Confidential Business Information’’ at the top. All submissions requesting confidential treatment must conform with the requirements of section 201.6 of the Commission's Rules of Practice and Procedure (19 CFR 201.6). All written submissions, except for confidential business information, will be made available in the Office of the Secretary of the Commission for inspection by interested parties. To be assured of consideration by the Commission, written statements relating to the Commission's report should be submitted to the Commission at the earliest practical date and should be received no later than the close of business on April 25, 2001. All submissions should be addressed to the Secretary, United States International Trade Commission, 500 E Street SW, Washington, DC 20436. The Commission's rules do not authorize filing submissions with the Secretary by facsimile or electronic means. Persons with mobility impairments who will need special assistance in gaining access to the Commission should contact the Office of the Secretary at 202–205–2000. General information concerning the Commission may also be obtained by accessing its Internet server (http://www.usitc.gov).

List of Subjects

WTO, GATS, Energy services, Market access, Natural gas, Trade in services.

Issued: February 9, 2001.

By order of the Commission.

Donna R. Koehnke,

Secretary.

[FR Doc. 01–3891 Filed 2–15–01; 8:45 am]

BILLING CODE 7020–02–P

INTERNATIONAL TRADE COMMISSION

[Inv. No. 337–TA–436]

In the Matter of Certain WAP-Compatible Wireless Communication Devices, Components Thereof, and Products Containing Same; Notice of Commission Decision Not to Review an Initial Determination Terminating the Investigation on the Basis of a Settlement Agreement and Withdrawal of the Complaint

AGENCY: International Trade Commission.

ACTION: Notice.

SUMMARY: Notice is hereby given that the U.S. International Trade Commission has determined not to review the presiding administrative law judge's (‘‘ALJ's'') initial determination (‘‘ID'') terminating the above-captioned