ESMAP

Energy Sector Management Assistance Programme

Republic of South Africa

Options for the Structure and Regulation of the Natural Gas Industry

Report No. 172/95

JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run by the World Bank's Industry and Energy Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and 15 bilateral official donors in 1983, it focuses on policy and institutional reforms designed to promote increased private investment in energy and supply and end-use energy efficiency; natural gas development; and renewable, rural, and household energy.

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Energy Sector Management Assistance Programme (ESMAP)

Oil and Gas Division
Industry and Energy Department
The World Bank

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Preface

At the request of the government of the Republic of South Africa, the Energy Sector Management Assistance Programme (ESMAP) prepared this report, which recommends policies and regulations for the emerging gas industry in the country. Although natural gas has not played a major role in the South African economy to date, its importance is expected to increase substantially in the near future.

Natural gas is produced offshore South Africa, and domestic potential exists as well for production of coal-bed methane. Reserves of natural gas have also been discovered in Namibia and Mozambique, and concerted efforts are under way to put these discoveries into production. The Pande field in Mozambique, for example, is being developed with the World Bank Group funding.[1] South Africa is the only potential large-scale market for Mozambican and Namibian gas sources. To develop the potential market in South Africa and to produce and transport gas from domestic and neighboring sources will also require considerable amounts of capital and expertise. Most of this investment is expected to come from the private sector, so it is vital that the "rules of the game" governing the production, transmission, and distribution of gas in South Africa are spelled out as quickly and as clearly as possible to assure potential investors of the transparency and stability of the regime under which they will be operating.

ESMAP assembled a team to study the current and emerging situations. In response to the government's request, the team has narrowly defined the recommendations in this report to address only the structure and regulation of the gas industry. A team of counterpart specialists was put together from the government's Department of Minerals and Energy Affairs (DMEA) and the Minerals and Energy Policy Center (MEPC). The two teams spent two weeks together in July 1994 in Johannesburg, Pretoria, Cape Town, and Mossel Bay meeting 21 companies, research centers, government agencies, and public utilities with the most interest in gas development. The teams were well received and given full cooperation in their inquires as to the nature, size, and scope of the entity being visited, its interest in gas now and the future, the importance it saw gas as having for the future well-being of the country, the role of government in the future of the gas industry, and the obstacles to gas development. They were also asked about their preferences for the structure and regulation of a future gas industry.

All of the entities regarded the development of a vibrant natural gas industry as important for the country. All felt that it would be beneficial for South Africa to have an alternative source of energy and chemical feedstock, especially a hydrocarbon source that is nearby and environmentally more attractive than other fossil fuels. The availability of gas would be of great value to almost all of the entities. The interviewees expressed a

1. IDA Credit 2629-MOZ for $30 million was recently approved for a gas engineering project.

wide range of opinions on the preferable degree of government involvement in gas development—from no participation at all to total control of the development process. Most felt, however, that government should play a definite role in monitoring the industry to prevent abuses and ensure safety but that it should not get involved in commercial arrangements such as price setting and contract negotiation. Above all, there was a consensus that the government, after consultation with the likely participants, should spell out clearly the policies and regulations that will guide the industry. In January 1995, the ESMAP team discussed a draft report with the government and entities they met in July 1994, and all were given the opportunity to comment on the draft. This final report thus reflects discussions with the government and all entities that provided comments.

Acknowledgments

This ESMAP report was prepared after two missions to South Africa in July 1994 and January 1995. The following staff members and consultants contributed to the report: Bent Svensson (task manager), Peter Glenshaw (senior industrial specialist), William Porter (senior energy specialist), and Robert Shepherd (consultant, gas industry specialist). Paul Wolman (editor) edited the report and supervised production, Dianne Thomas provided word processing assistance, and Gerald Brown prepared some of the illustrations.

The ESMAP team was assisted by the following South African counterparts: Godfrey Masango, Grove Steyn, and Hilton Trollip of the Minerals and Energy Research Centre, and Tony Surridge, Arthur Dykes, and Johan Botha of the Department of Minerals and Energy Affairs.

The mission operated in close cooperation with the South African government's Department of Mineral and Energy Affairs under the guidance of Mr. Johann Basson, chief director, energy.

The ESMAP team gratefully acknowledges the open, frank way it was received by all it came in contact with and the many helpful facts and opinions that the interviewees provided.

Abbreviations and Acronyms

CEF	Central Energy Fund
DMEA	Department of Minerals and Energy Affairs
EIA	Environmental Impact Assessment
ESMAP	Energy Sector Management Assistance Programme
FERC	Federal Energy Regulatory Commission
HDPE	High-Density Polyethylene
JWGD	Johannesburg Water and Gas Department
LPG	Liquefied Petroleum Gas
MEPC	The Minerals and Energy Policy Centre
Gauteng	Former name: PWV (Pretoria, Witwatersrand, Vereeniging)

Units

Currency Equivalents

1 South African Rand	=	US$0.27
1 US$	=	R 3.65

Prices

R 8/GJ	=	about US$2.2/mmBtu
R 12/GJ	=	about US$3.25/mmBtu
R 30/GJ	=	about US$8.2/mmBtu

General

m	= thousand	(10^3)	**k**	= kilo	(10^3)
mm	= million	(10^6)	**M**	= mega	(10^6)
b, bn	= billion	(10^9)	**G**	= giga	(10^9)
t	= trillion	(10^{12})	**T**	= tera	(10^{12})
			P	= peta	(10^{15})

Volume

mcm	million cubic meters
bcm	billion cubic meters
bcmy	billion cubic meters per year
mcmy	million cubic meters per year
cm	cubic meter
	1 cm = 1,000 liters = 35.314 cf = 6.29 bbl

Heat and Energy, Power

Btu	British thermal unit
mmBtu	million Btu
	1 mmBtu = 253 Mcal = 293 kWh = 1.059 GJ
GJ	Gigajoule
	1 GJ = 239 Mcal = 277 kWh = 0.945 mmBtu
GJy	Gigajoules per year
MJ/cm	Megajoules per cubic meter
18-22 MJ/cm	Low-calorie gas sold by Gaskor and Cape Gas
37-40 MJ//cm	Usual energy content of natural gas

Miscellaneous

bar	1 bar = 14.5 psi
psi	pound per square inch; 1 psi = 6.895 kPa
kPa	kilo Pascal
km	kilometer

Rules of Thumb

1 tcf	= 30 bcm
1 mmBtu	= 1 GJ = 1 mcf natural gas (energy content)

Executive Summary

1 The government of South Africa requested guidance from ESMAP in preparing policies and regulations for the country's emerging natural gas industry. The recommendations in this report have been narrowly defined, as the government requested, to address only the structure and regulation of the downstream gas industry and not other major energy issues, such as subsidies for the manufacture of synthetic liquid fuels. To prepare this report, an ESMAP team, assisted by local counterparts, visited the main entities with an interest in gas in July 1994 and in January 1995 to seek information and ask their views on the introduction of natural gas. The team members were given every assistance, and the local contacts expressed a strong interest in participating in the development of a natural gas industry, which they see as important for the country.

The Gas Sector in South Africa

2 Natural gas is produced offshore South Africa. Soekor, the South African state-owned petroleum exploration and production company, has invited foreign and domestic oil companies to search for new oil and gas reserves offshore, and private companies have expressed interest in developing coal-bed methane. Large natural gas deposits have been discovered in Mozambique and Namibia, and neighboring South Africa is the only potential large-scale market for these new developments. Investors, meanwhile, need to know the "rules of the game" that will govern the production, transmission, and distribution of gas in South Africa before they commit to these large, capital-intensive projects. Few rules exist now—particularly with regard to downstream transmission and distribution, which is the main focus of this report—because gas presently plays only a minor role in meeting South Africa's energy needs, supplying only 1 percent of final energy demand. Coal is, and is expected to remain, the least-cost option in most applications in the Transvaal because of the large, low-cost reserves.

3 Gaskor operates the largest gas business, supplying the Gauteng area with some 0.6 billion cubic meters per year (bcmy) of low-calorie gas derived from its coal gasification and synthesis operations through a 700-km pipeline network. By international standards, this is a very small distribution system. The Johannesburg Water and Gas Department (JWGD) takes about 10 percent of the Gaskor supply and distributes it to 12,000 domestic and 3,000 commercial and industrial customers. Cape Gas supplies 600 customers in the Cape Town area with some 0.01 bcmy of coal gas, and Port Elizabeth Gas distributes an LPG/air mixture. The only natural gas operation is near Mossel Bay, where Mossgas uses some 1.8 bcmy of natural gas from the F-A field, 93 km offshore, to produce synthetic gasoline and diesel oil.

4 Sources of gas likely to be developed within the next decade are noted below. Further appraisal of reserves is required for all three discoveries:

- *Pande.* The Pande gas field, with reserves of approximately 65 bcm, is located onshore in central Mozambique. Plans are to transport the gas by pipeline 900 km to the Gauteng area, with a possible extension to Durban.
- *Kudu.* The Kudu gas field is located 120 km offshore Namibia opposite the mouth of the Orange River. Preliminary estimates of 85 to 230 bcm of reserves have been projected. This gas would be sold primarily in South Africa via a 600-km pipeline from the Orange River mouth to the Cape Town region.
- *Coal-bed methane.* Production of coal-bed methane is expected from coal deposits located 320 km northwest of the Gauteng area in the Waterberg. Preliminary estimates indicate at least 60 bcm of producible gas. The gas would be transported via pipeline to the Gauteng area.

All of these areas have potential for additional reserves, as indicated in Table 1.

Table 1 Gas Resources, South Africa Region

Site	*Potential (bcm)*
Off- and onshore RSA	120 - 730
Coal-bed methane	60 - 200
TOTAL RSA	150 - 930
Namibia	110 - 1,420
Mozambique	70 - 370

5 The market for natural gas is almost entirely in South Africa, although Mozambican and Namibian towns and communities within reach of the main transmission lines are also likely to be served. Market studies conducted by others indicate that the South African market in the Gauteng area, Eastern Transvaal, and Natal within easy reach of the Pande and Waterberg deposits could rise rapidly to 2.5 bcmy, as gas would displace other fuels and feedstock at prices of about $2 to 3/GJ. The potential demand could be even higher as users come to realize the benefits of gas. Large industrial plants will take a major share, followed by a tier of smaller industries and commercial customers. Domestic consumption is likely to be limited because the heating demand is small in South Africa's generally mild winters.

Options for Industry Structure

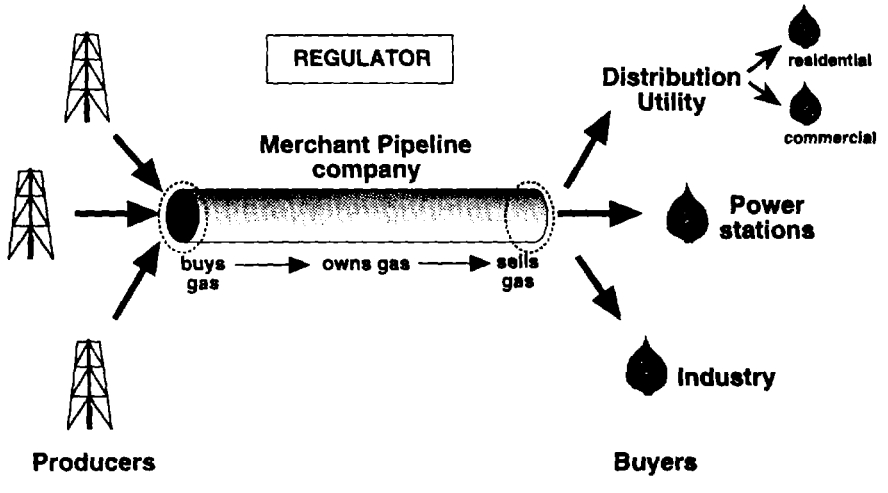
6 Production, transmission, and distribution of natural gas have different characteristics and should be handled by different companies. The gas industry has to cope with the dilemma of encouraging competition in the face of the natural monopoly that derives from economies of scale in the transmission of gas over long distances and in the distribution of gas to smaller customers.

7 Competition is feasible among companies producing gas from underground deposits. The price for natural gas delivered at the inlet to the long-distance pipeline can be freely negotiated between producers and buyers, taking into account costs, licensing procedures, royalties, and taxation that the host government will establish.

8 The main questions relating to the possible structure of the industry relate to how to encourage competition in the long-distance transmission pipelines. Two main options are immediately apparent. The first of these options involves giving the pipeline owner the right to buy gas into the pipeline and sell it at the other end—this is the "Merchant Pipeline" option (see Box 1 for a summary description).

Box 1 The "Merchant Pipeline" Option

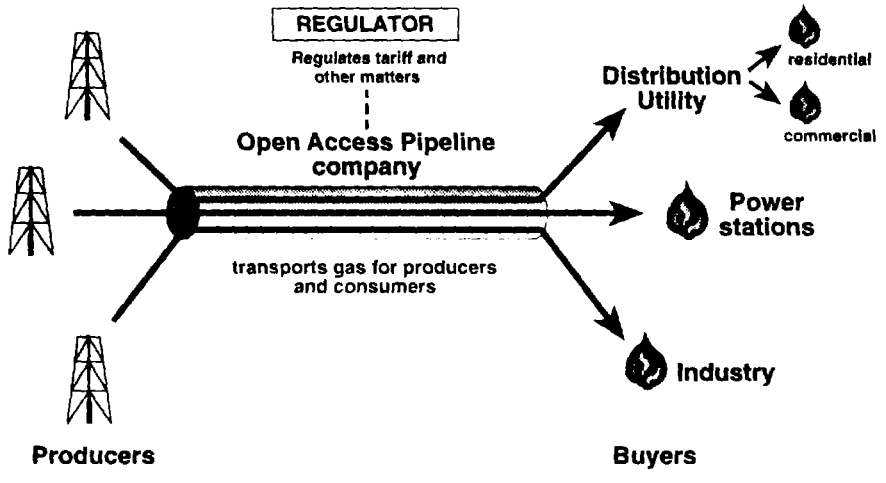
- The transmission company buys gas from producers, sells gas to customers, and is not required to transport gas for third parties. In effect, all customers must buy their gas from the transmission company.
- Prices are negotiated between the transmission company and the producers, on the one hand, and between the transmission company and the customers, on the other.
- The transmission company owns the gas in its system. There is therefore no visible transportation tariff.
- It is desirable to have distribution companies to handle small customers, as shown in the figure, but the transmission company could supply small buyers directly.



9 The second option involves specifying that the transmission company cannot own the gas it transports. Furthermore, any gas producer and any gas consumer can have access to transport their gas through the pipeline for a fixed and transparent transportation tariff—this is the "Open-Access Pipeline" option (see Box 2).

Box 2 The "Open-Access Pipeline" Option

- The transmission company is not allowed to buy and sell gas. It must transport gas for third parties on a nondiscriminatory basis.
- Producers sell directly to customers, and prices are set by direct negotiation between the producers and the customers.
- The producers or the customers, not the transmission company, own the gas in the pipeline system.
- The transmission company charges a tariff for transporting gas; the tariff is regulated by an external regulator.
- Distribution companies are needed to serve smaller customers because producers need to sell on long-term take-or-pay contracts and these are only viable from large customers.



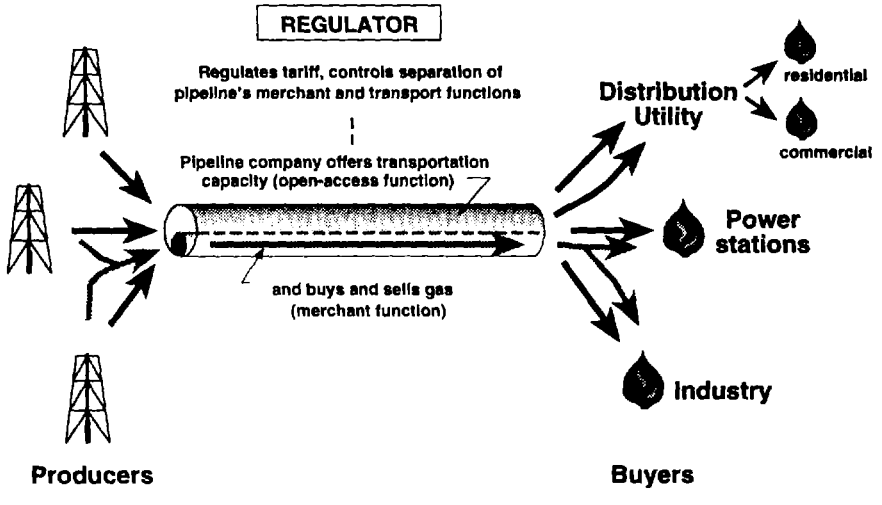
10 The pros and cons of these two options for industry structure relate mainly to the degree of competition and the possibilities for commercial financing. The Open-Access Pipeline has potential for competition in supplying customers because producers sell directly to major customers. Financing the pipeline could be difficult, however, as the lenders will perceive greater risk here than for a merchant pipeline. Open access implies that many players will be involved. This diversifies the risks but also makes them more difficult to understand. Moreover, until now, open access has been introduced only in mature gas industries. A Merchant Pipeline has a monopoly in transmission of gas, so it would not involve gas-to-gas competition between producers in supplying customers. The Merchant Pipeline would, however, be the most attractive option for potential investors in the pipeline. The attractiveness of the Open-Access option would be increased, however, if an enhanced return compensated for the higher risk.

11 The recommended strategy is a "hybrid" of the two foregoing options that could take advantage of the strong points of both approaches—attractiveness to investors and enhanced potential for competition. In the hybrid option, the transmission company would be allowed to buy and sell gas on its own account, but it also would have to offer

open access to its transportation capacity to third parties. However, to ensure a level playing field, the merchant and the transport functions of the transmission company must be run as arms'-length activities in separate subsidiaries. The same transportation terms and tariffs must apply to the merchant business as to the third-party users. Distribution companies are desirable here, but they are not essential, as the merchant part of the transmission company can itself supply smaller industrial customers. Because the pipeline company both sells its own gas and transports gas for others, the large customers and distribution companies would have a wider array of options for gas supply. As a result, competition in the market would be increased compared with the other options.

Box 3 The Recommended "Hybrid" Option

- The transmission company is allowed to buy and sell gas on its own account, but it must also offer open access to its transportation capacity to third parties.
- Prices are set by negotiation. Customers and the transmission company compete to purchase from producers, and producers and transmission company compete to sell to customers.
- To ensure a level playing field, the merchant and the transport functions of the transmission company must be run as arms'-length activities in separate subsidiaries. The same transportation terms and tariffs must apply to the merchant business as to the third-party users.
- Transportation tariffs and access rules must be regulated.
- Although it is desirable to set up distribution companies, they are not essential in the way that they are for the Open-Access option, as the merchant part of the transmission company can supply smaller industrial customers.



12 Under all three options, natural gas would not be able to compete at prices higher than those of other fuels at the point of consumption. Large customers, generally,

would turn to an alternative fuel supply if gas prices rose and stayed at a higher level than competing fuels. Residential and small commercial and industrial customers without other fuel alternatives ("captive customers"), however, would need to be protected by a cap on price increases.

The Role of the Government

13 Private industry appears willing to develop gas to supply South Africa and to distribute and market gas within the country. Therefore, the state should not need to use its limited capital resources to develop the gas business. However, the government should gear up for the important roles it will play in helping to introduce natural gas to the South African economy. Its principal tasks, in rough order of importance, would be as follows: setting up and monitoring the regulatory framework, negotiating cross-border arrangements for importing gas from Mozambique and Namibia, and evaluating proposals that are likely to come from investors. These roles are discussed briefly below.

Developing and Implementing the Regulatory Framework

14 Companies wishing to get involved in the downstream natural gas industry in South Africa will need to know the regulatory environment in which they will operate. It is essential, therefore, that the government give considerable thought to this issue if it wishes to attract private investment capital to the sector. These "rules" should not be changed after companies have invested in good faith. Most countries with natural gas industries have introduced a regulatory framework, so-called Gas Acts, and this approach would also be useful in South Africa. A Gas Act should be applied nationally to new entrants as well as the existing gas industry.

15 Regulation is recommended for gas transmission tariffs and for distribution costs for gas supply to small, captive consumers. The regulation should ensure that investors would have an incentive to keep costs down and earn extra profits. A price cap that would limit the increase in distribution costs to small, captive customers would provide for such an incentive, and the regulation of pipeline tariffs should be based either on a price cap or on a rate-of-return regulation with incentives for the transmission company to reduce costs. Gas purchase costs, however should be passed through to the customer. The government or a regulatory agency would be responsible for the regulation. For large customers, end-user prices would not be regulated (except for the transmission cost), since these customers would turn to other fuels if gas prices stayed at a higher level.

16 A downstream regulatory function would be required under all three options for industry structure (Boxes 1 to 3), but initially it would not need to be a large organization. The main duties would be as follows:

- Implement a Gas Act and its regulations.
- Issue permits authorizing construction and operation of pipelines.

- Regulate the costs of supply to captive customers.
- Prevent anti-competitive and discriminatory behavior and abuse of monopoly.
- Set the terms and conditions for competitive award of franchises.
- Enact regulations governing safety, technical, and environmental standards; billing for normal service; and billing for connection, interruption, and reconnection of service.
- Ensure that the franchisees maintain their systems in good order.

17 If open access is introduced (in the open-access pipeline option or the recommended hybrid option), the regulatory requirements would be expanded further to regulate the tariffs and other conditions of service for the franchises of open-access operations. Moreover, the regulatory agency should ensure that anti-competitive and discriminatory behavior are avoided in providing access to the pipeline and between the merchant and the transport function of the pipeline company in the recommended option.

Negotiating Cross-Border Arrangements

18 Cross-border arrangements need to be completed with Mozambique and Namibia. Particular areas where policies and procedures need to be harmonized include the following:

- Pipeline routing
- Construction timetable
- Capacity
- Financing
- Taxation
- Tariffs
- Competitive terms for goods and services
- Technical standards.

Evaluating Proposals

19 Proposal evaluation would be necessary if the government actively called for proposals from investing consortia or if the government decides to negotiate directly with interested parties. It is recommended that South Africa announce that it is prepared to evaluate proposals for transmission and distribution franchises. This is common in the gas industry and has the advantage of bringing in international experience, new ideas and new capital at the lowest possible cost. Experience shows that investors often propose pipeline systems and tariff structures that would otherwise not have been thought of when there is some degree of open, international competition. The franchise for pipelines should enable the holder to construct the pipeline. For transmission pipelines, the franchise should not be exclusive, and distribution companies should have an exclusive

right to build pipelines in the franchise area, except for special cases. However, they should not have a monopoly to sell gas in the franchise area.

Ensuring Long-Term Role of Gas

20 In addition to the issues preceding the introduction of natural gas in South Africa, several issues that are linked to the long-term development and competitiveness of natural gas will need government attention. These issues are not addressed in detail in this report, inasmuch as they fall outside the scope of the study:

- Integration of the existing gas distributors—Gaskor, JWGD, Cape Gas, and Port Elizabeth gas—with the new natural gas systems.
- Improvement of the terms under which rights to coal-bed methane are granted, especially distinguishing the rights to coal from the rights to gas.
- Consider allowing pipeline owners to write off depreciation of pipelines; this is presently not allowed, as pipelines are considered permanent infrastructure, which is not depreciable.
- The eventual restructuring of Soekor—and the optimal timing of the restructuring in relation to the recent licensing round—so that its upstream regulatory role is managed separately from its role as the state exploration and production company.
- Earmarking subsidies and grants to Sasol for synthetic fuel production so that they are kept at arms' length from its other businesses, especially its Gaskor operations.
- Evaluating the several studies now in progress concerning the future of the Mossgas Project. If the outcome is that it would be possible to supply Cape Town with gas from Mossel Bay, the government would have a role in ensuring that a level playing field is maintained for the fiscal regime.
- Understanding the potential impact on gas development of the decontrol of liquid fuels.
- Assessing LPG' s role in meeting the energy needs of the country.

1

The Gas Industry in South Africa

1.1 The existing gas industry in South Africa is small. Domestic gas production potential appears to be modest, by international standards, and current piped gas consumption amounts to less than 1 percent of total final energy used in the country. Nonetheless, the impending development of major gas discoveries in Mozambique and Namibia, near to those countries' borders with South Africa, could make available substantial supplies of gas. South Africa is the only market for these supplies, which, together with domestic gas and coal-bed methane, could serve the energy needs of a number of South African industrial and commercial consumers, with demand rising as users recognize the efficiency and environmental benefits of gas. For these reasons, the further development of the South African gas sector and the appropriate structuring of the sector are matters of interest and concern to various parties in government and industry.

1.2 This chapter reviews the activities of the current participants in the gas sector; discusses the characteristics and potentials of the three main sources of gas that could be developed in the near-to-medium term to serve the South African market (i.e., Pande in Mozambique, Kudu in Namibia, and the domestic coal-bed methane resources of the Waterberg in Northern Transvaal); briefly notes the shape and limitations of the potential South African gas market; and discusses several issues relating to the gas infrastructure and administrative arrangements such as the state's role and its regulatory, licensing, and taxation procedures, that could affect investment and development in the sector.

The Present Industry Participants

1.3 The present industry consists of a mid-size gas distribution network for coal-based gas in the Gauteng area, a much smaller one in Cape Town, and a limited LPG/air distribution network in Port Elizabeth. In addition, natural gas from an offshore field fuels the manufacture of liquid petroleum products at the Mossgas plant. There is a large system of LPG distribution in bulk and in bottles. Finally, many factories have their own gas production based on coal. The principal participants in the sector are discussed below.

Gaskor

1.4 Gas consumers in the Gauteng area are supplied by Gaskor, a wholly owned subsidiary of Sasol that currently sells between 23 and 24 million GJy (0.6 bcmy at 40 MJ/cm). Gaskor owns about 700 km of distribution pipe, serving about 700 mainly industrial customers. It has some commercial clients and also supplies the Johannesburg Water and Gas Department (JWGD; see below), which itself serves a mix of industrial, commercial, and domestic customers in the Johannesburg area.

1.5 About 95 percent of the gas supplies for the Gauteng area presently come from the coal gasification and synthesis operations of the Sasol 1 plant at Sasolburg. The remaining 5 percent come from the Sasol 2 and 3 plants at Secunda. The gas has a calorific value of 20.5 MJ/cm—about half the 37 to 40 MJ/cm of natural gas. The Secunda plant can produce gas with a higher calorific value (about 34 MJ/cm), from in-plant process streams, which are rich in methane. The new pipeline of some 100 km that has just been completed from Secunda to Witbank and Middelburg will supply the metallurgical industry and other users with high-calorific-value gas. Gaskor has decided to expand the gas business to the Kwazulu Natal area (Richard's Bay). The gas sent there will have a high calorific value and will be supplied to the area through Petronet's pipelines (see below).

1.6 Significant expenditures, particularly in the Johannesburg municipality, would be required to convert the network to natural gas. Much of the cost would be for customer conversion, although some would probably have to go to renewal of pipework. Gaskor has the option to convert the existing network to a heating-value-equivalent to natural gas. Whether to do so and the timing of such a decision if it were made would depend on technical and economic considerations, including the costs of converting the customers.

1.7 The price of Gaskor gas is geared to maximize load factor and therefore to reduce the cost of supply and maximize returns. No volume discounts are given (above the smallest loads). Load factor is monitored carefully. Customers have meters that record maximum hourly and daily demand, and both of these are controlled in the sales contracts. Rather surprisingly, load factor is calculated on a monthly basis (it used to be calculated annually, but customers complained that a low load factor in a single month could lead them to pay higher prices for a whole year). There are no capacity or fixed charges and no interruptible customers. The limited load variation is managed through line pack, particularly at weekends, and by the use of backup streams of gas available at the plants. Many customers have energy management and storage systems to maximize their load factors.

1.8 Customers have individual contracts, but prices are set by a published tariff that is reviewed annually. One or two large customers have indexed prices. Customers are required to give six months' notice if they wish to cease taking supplies. A single sliding-scale tariff is used that ranges from about R 12/GJ at load factors of 90

percent and above to R 31/GJ at load factors below 40 percent. The price at the low end of the tariff is close to the level of delivered heavy fuel oil prices, whereas that at the high end is close to the level of LPG prices. In contrast to the situation on the Gauteng area network, where prices for almost all customers are set by a published tariff, the commercial arrangements on the new Witbank line are mostly individually negotiated and are primarily geared toward particular large users.

1.9 Gaskor is set up as a "Section 21" nonprofit company. It simply owns pipe networks. It has no staff, and all sales, operation, and maintenance are carried out by Sasol.

Johannesburg Water and Gas Department

1.10 JWGD's origins are as a town gas producer distributing coal gas through its own pipes in the Johannesburg area. It takes about 10 percent (2.4 million GJy) of the Gaskor supply, of which it sells 87 percent to industrial and commercial customers and the remainder to the domestic sector. JWGD has a total of 15,000 customers, of whom 12,000 are domestic. The company has 1,300 km of distribution pipe, mainly steel. This pipe complies with British standards (rather than the American standards followed by Gaskor). There are two pressure tiers. Gas is received from Gaskor through five pressure-reduction stations.

1.11 JWGD buys gas from Gaskor at a high load factor and allows for seasonal swings by means of storage (one high-pressure facility and three gas holders) and interruptible customers. Some 25 large customers are on interruptible contracts of one-year duration at a modest discount to firm prices, and these account for about 10 percent of JWGD's sales. The market is static or possibly falling slightly, probably because of the high price of R 28 to 30/GJ charged to firm industrial customers. Part of the reason for the high price is the high level of overhead charged by the Johannesburg Municipality for services provided to JWGD. The price of gas purchased from Gaskor is about 12 R/GJ.

1.12 The average price charged to the domestic sector is R 32/GJ, which does not provide enough return to justify extending the domestic grid to expand the market. This price covers the average costs of supplying all customers but does not reflect the marginal costs of supplying small domestic customers. In other countries, as a rule of thumb, domestic prices average about twice the price to large industrial users.

Cape Gas

1.13 A small amount of coal gas is distributed in the Cape Town area by Cape Gas. This company is privately owned and has probably the only surviving coal gas plant of its type in the western world. The plant's origins date to the 1840s, and significant parts of the plant and the distribution pipework are more than a hundred years old. There is about 250 km of pipe of up to 18 inches diameter, mainly in cast iron. About 20 km of the pipe has been replaced by HDPE conforming to a Cape Gas standard that predates the widely recognized British Gas code. If natural gas was introduced into the system, much

of the cast iron pipe would doubtless need to be replaced. A customer conversion program to allow the burning of higher-calorific-value gas would also be required.

1.14 Total sales of Cape Gas are about 0.4 million GJy of low-calorific gas of about 18 MJ/cm (0.01 bcmy at 40 MJ/cm). The company serves a broad mix of domestic, commercial, and industrial customers. About 2 percent of the supply goes to the domestic market, where there are now only about 600 customers (down from 8,500 mainly because of demolition of older residential areas and competition from electricity). Characteristically, the 60 largest customers take some 85 percent of total volume.

1.15 Cape Gas has a more flexible sales policy than Gaskor. Prices are individually negotiated with large industrial customers, and domestic and commercial customers are on a fixed tariff. The tariff is heavily volume weighted and does not penalize load factor to the extent that Gaskor does. Prices range from R 22/GJ to R 40/GJ.

1.16 The operators would like to convert to natural gas as soon as the gas can be made available. Cape Gas sees significant demand potential in areas it cannot now supply. Lengthy negotiations were held with Mossgas for supply of gas either by pipeline or as LNG in road tankers from the Mossgas LNG plant, but these did not result in an agreement.

Port Elizabeth Gas

1.17 The only other gas distribution system in South Africa is a privately owned company in Port Elizabeth, Port Elizabeth Gas. The company has converted from town gas to distributing an LPG/air blend. The operation is on a small scale—that is, approximately the same size as Cape Gas.

Mossgas

1.18 The only natural gas production in South Africa is from the 20 bcm F-A field in 105 meters of water 93 km offshore Mossel Bay. The complex includes an offshore production and treatment platform with nine wells. Gas and condensate are separated offshore, and the gas is dried and refrigerated to specification on the platform. An 8-inch line takes condensate to shore, and the gas is carried in an 18-inch line. To ensure total reliability of supply, a small LNG plant and storage tank have been constructed onshore. The whole output of this operation is owned by and dedicated to the government-owned Mossgas liquids synthesis plant. Gas production is currently running at about 1.8 bcmy.

1.19 The future of the Mossgas plant is under review. Several options for continuing with the Mossgas operations or otherwise are being studied, but until these studies are complete, no accurate assessment of the availability of F-A gas for the local market can be made.

Future Potential

Possible Sources of Gas

1.20 The three main sources of natural gas that could be developed for the South African market over the next few years are the Pande field in Mozambique, the coal-bed methane of the Waterberg in Northern Transvaal, and the Kudu field in Namibia. Gas from Mossel Bay also could be put onto the market, and this is one of the options presently being studied. A number of satellite accumulations around FA are still being appraised and could provide further quantities of gas. In the longer term, there is potential from further exploration in South Africa, principally offshore the West Coast. Significant potential exists in Namibia and Mozambique in addition to the Pande and Kudu discoveries. If a major market does develop in South Africa and local supplies become a problem, the country could no doubt gain access to the massive reserves in the Middle East or even Nigeria in the form of LNG. Angola could also be a potential supplier in future.

1.21 In what follows, the chief characteristics, size, and relative importance of the main sources are presented based on the discussions with potential producers and with Soekor—particularly the recent report prepared by the consulting firm Intera of the United Kingdom. No new technical work has been done by the ESMAP team.

1.22 **The Pande Field.** The Pande field is located some 600 km northeast of Maputo about 25 km inland from the coast north of Inhassaro. A 900-km pipeline will be required to deliver gas from the field to the Johannesburg area. As the field itself is relatively shallow (less that 1,500 meters), of simple geological structure, and onshore, it will be relatively cheap to develop. The pipeline represents the major investment. Following the successful completion of the Pande 11 well and recent high-quality seismic testing, proven recoverable reserves are now put at 65 bcm (2.3 Tcf), and more upside potential is possible. Further appraisal drilling to confirm the reserves is required, however.

1.23 Mozambique's state oil company, ENH, and Enron Corporation of the United States are working to develop a project to produce and pipe some 2 to 3 bcmy of gas to the Gauteng/Phalaborwa area, and possibly also to the Richard's Bay/Durban region. The current focus of activity is to prove more reserves and access the market potential. Project structure is not yet well defined.

1.24 The project has ambitions to start up in 1998. That goal is attainable but nonetheless would represent a considerable challenge. One of the critical tasks to be done to meet the target startup date is the development of gas policy frameworks in both Mozambique and South Africa.

1.25 **The Waterberg Coal-Bed Methane Deposits.** Coal-bed methane appears to have high potential in South Africa. The Ellisras area of the Waterberg in Northwest Transvaal is particularly promising. This gas is particularly well located in terms of its market, at only 320 km from Johannesburg. Preliminary work by Shell and

Anglo-American indicates the possibility of at least 57 bcm (2 Tcf) from their acreage in the area. This contrasts with Intera's view of only 86 bcm (3 Tcf) as the mean potential for the country as a whole.

1.26 Further detailed appraisal work is being delayed by the unfavorable tax regime, which does not allow development costs to be deducted from general corporate income—a practice sometimes referred to as *ring fencing*. The question of who owns the rights to the gas was explained by DMEA as follows: On private land, the law specifies that the landowner owns all minerals rights (including natural gas), except where these rights have been separated from the ownership of the land, in which case the holder is the person in whose name the mineral rights are registered in the deed office by means of a certificate of mineral rights. As a result, coal can be leased separately from the coal-bed methane. On state land, where the work is presently being done, the question of who owns the mineral rights is not so important. Shell and Anglo-American feel that if these issues can be resolved soon, development could progress in a similar time frame to the Pande project.

1.27 For convenience, in what follows, the current holder of the rights, whether the landowner or not, is referred to as the "mineral rights owner." On private land there is some potential for conflict between the production of coal and the exploitation of coal-bed methane. When the rights are separated, the lessees have no option but to negotiate an agreement with each other as to how they will resolve the conflict. A further problem with the vesting of mineral rights to a variety of private owners, at least from a traditional upstream oil-and-gas-company viewpoint, is that it may be necessary to negotiate leases with a number of owners on different terms in order to cover a whole deposit. This is very different—and far more complex and uncertain—from the process of obtaining rights from the state to clearly defined blocks of acreage under fairly standardized terms. It is also in strong contrast to the situation of rights offshore, where the more conventional regime does, in effect, apply.

1.28 **The Kudu Field.** The Kudu field is located 120 km off the Namibian coast nearly opposite the mouth of the Orange River. The deposits are in deep water that is subject to rough weather and therefore will be more difficult and expensive to develop than Pande. The initial target would be the Cape market, which has a higher value but smaller volume than the Gauteng market and requires only about 600 km of main transmission pipe. Based on currently available information, the Kudu discovery is estimated (by Intera) to contain at least 57 bcm (2 Tcf). Kudu is a large structure that requires considerable further appraisal. Recently, 3D seismic was shot and is now being processed. Shell, the operator, feels that potential reserves could be in the range of 85 to 230 bcm (3 to 8 Tcf) and are more likely to be at the higher rather than the lower end of the range.

1.29 Gaining sufficient sales to sustain the development is the main challenge. Kudu would require a substantial baseload customer to be viable, and discussions are taking place with ESKOM on the possibility of a large, gas-fired power station at

Saldanha Bay. The startup of the project is likely to be after the year 2000 to allow further field appraisal and the lead time required for market development.

1.30 Shell wants to see a well-established policy framework before committing large sums to the venture. Particular issues are that there should be an accord with Namibia that allows the required international pipeline to be built and operated without problems, and that the future of Mossgas is resolved in a way that allows Mossel Bay gas to compete fairly with Kudu gas.

1.31 **Regional Offshore Potential.** This is modest by international standards. Soekor opened an offshore exploration licensing round in October 1994. Table 1.1, adapted from the Intera report, summarizes the potential resources in South Africa, Namibia, and Mozambique.

Table 1.1 Gas Resource Potential in Southern Africa (bcm)

Basin	*Reserves*[a]	*Discoveries*[b]	*Potential*[c] *(min)*	*Potential*[c] *(most likely)*	*Potential*[c] *(max)*
RSA					
South Coast	20	43	43	80	171
West Coast	0	3	57	143	371
East Coast	0	0	14	23	43
Onshore	0	0	9	29	143
Coal-bed methane	0	0	29	86	200
RSA Total	**20**	**46**	**152**	**361**	**928**
Namibia					
Namibia Total	**0**	**57**	**114**	**425**	**1,416**
Mozambique					
Rovuma	0	0	17	34	86
South	54	0	49	114	283
Mozambique Total	**54**	**0**	**66**	**147**	**369**
TOTAL ALL COUNTRIES	**74**	**103**	**332**	**933**	**2,627**

Source: Intera, *The Gas Potential of RSA and Neighboring Countries, 1994.*

[a]*Reserves:* most likely (i.e., 50 percent probability), either developed or capable of producing.

[b]*Discoveries:* also 50 percent probability, discovered but not developed or declared commercially developable.

[c]*Potential:* predicted to be present and commercial, but not drilled. Minimum and maximum are roughly 90 percent and 10 percent excedence cases.

1.32 None of the areas has been intensively explored, although the Bredasdorp basin in South Africa is moderately well understood. All these areas would presently be considered high risk by the international oil industry. As they are principally gas prone (particularly in the shallower water areas offshore), they carry the added risk that there is no developed market or infrastructure for gas, and therefore markets would have to be developed before any gas discovered could be sold. This adds substantially to the perceived exploration risk.

Markets for Natural Gas in the Region

1.33 The market for natural gas in the region will be almost entirely in South Africa. Small amounts of gas are likely to be supplied to Namibian and Mozambican communities within reach of the trunk pipeline, including Maputo and eventually other cities. The South African market for gas has been studied with increasing intensity over the past three years by various parties. The studies have come to similar conclusions on the general size and characteristics of the market for gas:

- In the areas most accessible to Pande gas and coal-bed methane—that is, Gauteng, Eastern Transvaal and Durban/Richard's Bay—demand probably will rise rapidly (i.e., within five years) to some 2 to 3 bcmy, as gas will readily displace other fuels or feedstock at a price of about R 8 to 12 per GJ ($2 to 3 per mmBTU); eventual demand could be two to three times greater.
- The market in the Cape has not been as intensively studied.
- The South African gas market consists of five segments, which in decreasing order of importance are as follows:
    - The "prime users"—big industrial consumers that either now use other fuels they will replace with gas or will invest to make use of gas. Examples are the existing coal-based ammonia plant at Modderfontein and new plants to produce direct-reduced iron.
    - Gas-fired power plants using combined-cycle technology.
    - Another industrial segment where smaller users will replace existing fuels such as HFO, LPG, diesel oil, and electricity to gain the advantages of gas such as convenience and clean burning.
    - Commercial operations such as hotels, restaurants, and office buildings.
    - Domestic consumers, especially apartment blocks, homes already connected to a coal gas supply, and—possibly—new connections.

1.34 The South African energy market is an unusual one in that large quantities of low-cost, low-sulfur coal are available, and coal would be the least-cost option in many applications. Natural gas will not be able to compete with this coal for bulk heat production (as petroleum products cannot). Gas would be more competitive, however, if

the full environmental cost of coal is taken into account—but this is unlikely in the near term. Gas will be able to compete with coal in some industries where coal is used today but usually only when reinvestment in new facilities becomes necessary. It can also compete in lower-volume, higher-price applications and for specialized uses, such as replacing producer gas. At this level, coal effectively competes with heavy fuel oil.

1.35 Gas will also compete with gas oil and LPG in static applications. In South Africa it will also compete with the 40 percent of electricity that is used in heating applications. Gas is clearly price competitive with electricity for industrial clean heat applications, although electricity is still indispensable for certain specialized applications such as induction heating and electric arc furnaces.

1.36 It seems unlikely that gas will achieve high penetration in the domestic sector. South Africa's mild winters minimize the space heating requirements of households, and cooking and water heating loads are usually insufficient to justify the cost of connecting a gas supply. Connection costs will also be high in South Africa because of the country's low housing densities. Moreover, because electricity connection is essential, the government is unlikely to see a social need to connect gas as well to disadvantaged areas as part of its reconstruction and development plans. Nonetheless, some extension of existing networks, particularly to houses where loads are larger than average, should be studied for cost effectiveness. Some gas demand may also come from isolated rural communities in reach of branch lines from the main transmission lines.

1.37 ESMAP made no attempt to survey the market for gas in South Africa, but the government may wish to examine further the role of natural gas in the residential sector. Alternatives for space and water heating and cooking—including LPG, electricity, and coal—need to be analyzed to determine the least-cost option.

1.38 CEF, however, has developed a fuel substitution model that is based on the energy data base assembled by the Institute for Energy Studies of the Rand Afrikaans University. The CEF model generates gas penetration rates by looking at relative fuel prices and at natural turnover of the capital stock invested in using a particular fuel. It does not take account directly of the use of baseload customers to launch developments, nor does it consider marketing efforts to accelerate penetration, and therefore it is a better indicator of market potential than of rate of penetration. The model predicts a general demand of about 0.9 bcmy in 1998 (excluding Mossgas), rising to 5.25 bcmy by 2010, and to 7 bcmy by 2020 assuming 2 percent annual GDP growth and at a gas price of R 12.5/GJ, which is close to current prices in the Gauteng area for high-load-factor gas, around the level of delivered heavy fuel oil prices, and even higher than the price of industrial coal. This is a modest sales level. Acquisition of a major power station, such as Saldanha Bay, as a baseload customer would increase sales potential substantially.

Gas Transmission Infrastructure: The Role of Petronet

1.39 Apart from the Gaskor network and the pipelines connecting the F-A field to Mossgas, South Africa has no gas transmission infrastructure at present. However, the

country does have a number of "underutilized" petroleum products lines that, with some modifications and additional linkages, could be converted to gas use at moderate cost to provide a high-pressure gas trunk line from Richard's Bay in Kwazulu Natal to Secunda. The line belongs to Petronet, the pipeline subsidiary of Transnet (the state-owned transportation company whose main operations are the extensive rail, airline, and port network in the country).

1.40 Petronet recently signed an agreement with Sasol to ship high-calorific-value gas from Secunda to Kwazulu Natal through former petroleum product lines. After investments of R 130 million, the gas pipeline will operate on an open-access principle subject to available capacity. The technical specifications for gas to be transmitted in the pipeline make the transmission of natural gas possible. Petronet would also like to participate in the construction of new trunk lines for gas transmission. It is aware that it has no experience in trunk gas lines but feels it can rapidly gain the necessary expertise, as it did for oil lines over the past 20 years. In addition, Transnet is rapidly increasing its regional operations and feels it could participate, or even have a controlling interest, in the international gas transmission lines that would connect South African markets and Namibian and Mozambican sources.

Issues Raised by Current Status

1.41 This section highlights the factors that are peculiar to the current gas industry in South Africa and form the background to the recommendations for industry structure and regulation. It does so by identifying a number of issues that appear to require attention of the government because they would affect the introduction and long-term supply of natural gas.

Strategic Value of Gas

1.42 The potential resources of gas within South Africa appear to be modest so far, and until and unless more gas is found, it is likely to be primarily an imported fuel, albeit from nearby countries of profound importance to South Africa. This brings uncertainty to the importance gas is likely to have in the future energy mix in South Africa. High-ash, low-sulfur, cheap indigenous coal will probably continue to provide the major proportion of the nontransport energy requirement. As long as the full environmental costs of using coal are not made explicit, the low price of coal in South Africa even reduces significantly the advantage that gas enjoys elsewhere in the world for electricity generation. In most countries, it is the electricity sector that holds the key in the long term as to how significant gas becomes in the energy mix. In addition, the market for domestic space heating is a large factor in markets in colder countries that is not likely to play a major role in South Africa.

1.43 Despite its differences from other gas markets, South Africa still should find a significant use for natural gas in the energy and chemical feedstock markets. Although there seems to be little reason to promote gas purely on strategic grounds,

South Africa can derive unquestionable benefits from using gas in diversifying its energy supplies. Perhaps the best strategic argument for gas is that it could hold the key to economic progress in Mozambique and Namibia, which would be of benefit to South Africa.

Offshore Licensing

1.44 By international standards, South Africa has only modest potential for finding gas, both offshore and onshore. Recognizing the time that will be needed to develop gas markets, Soekor is proposing to modify the licensing terms to give gas discoveries more time for appraisal and marketing. The basic fiscal terms are, however, the same for both gas and oil and do not give any recognition to the lower value and greater difficulty of developing gas. This is not uncommon in many parts of the world, but competition between countries for exploration funds is fierce. If the licensing round fails to attract enough support, consideration should be given to relaxing the terms. Terms that are likely to be particularly unpopular with the exploration industry, because of their regressive nature, are the royalty and the carry of Soekor through exploration; these could be the first to receive scrutiny. The royalty is nevertheless negotiable. Compared with coal, which is more lightly taxed, gas is at a competitive disadvantage, and steps should be taken to equalize the tax regimes.

Onshore Licensing and Coal-Bed Methane

1.45 The onshore regime is also in urgent need of attention, particularly regarding coal-bed methane. Although the licensing provisions are very similar to the situation in the United States, these are not very conducive to the development of coal-bed methane in South Africa. In the United States, the landowner has the mineral rights; this works reasonably well, largely because the amount of prospective acreage is large, and landowners compete with one another to attract exploration. Terms are fairly well understood, and prices are set by an active market. Such conditions may apply for a number of minerals in South Africa, but so far they seem not to hold for gas or coal-bed methane. The mission heard several times that the situation could be improved by returning rights to hydrocarbons to state ownership (or reinstating the former Soekor lease to onshore acreage, which would have a similar effect). Such a move would simplify the licensing, but to return to state ownership the government would have to revoke rights granted by the 1991 Minerals Act.

Tax Treatment of Pipeline Investment

1.46 It is an unusual facet of South African tax law that pipeline investment is treated as investment in "permanent" infrastructure, and no depreciation on the pipeline investment can be charged to the income of the pipeline owner. Oil and gas are under the mining legislation, and annual expenditure on investments in mines, including pipelines installed as a part of the mining operation, can be deducted from income. No such legislation exists to cover pipelines as such; thus, if a transmission line is regarded as a structure, no tax relief would be available for construction costs. In other countries,

owners of pipelines can deduct the cost of the pipelines for tax purposes (see Annex 3). However, this type of fiscal regime is not the way to develop more extensive gas transmission and distribution networks. The government thus should consider allowing pipeline owners to write off depreciation of pipelines so that investors in pipelines are not put at a disadvantage.

The Role of Soekor

1.47 Soekor acts as a state petroleum exploration and production company. It also administers offshore licensing through a sublease, subject to ministerial oversight and approval. It is 100 percent government owned through CEF. It recently transferred the production lease for the F-A field to Mossgas. It clearly acts as a source of technical expertise to government, and both Soekor and CEF have been active in developing policy ideas in the oil and gas field. It is less clear to what extent these ideas represent a government or a "corporate" view.

1.48 It is desirable to separate clearly the regulatory function from the role of a state oil company as an active participant on behalf of the state in the exploration and production of hydrocarbons. The government should consider putting the licensing, regulatory, and policymaking functions into the DMEA, thus clarifying Soekor's role as an active exploration company.

The Role of Sasol

1.49 The position of Sasol and Gaskor presents a dilemma for structuring a gas transmission and distribution system in the Gauteng area. The company has a vertically integrated de facto monopoly of the gas business in the area, as it controls both production and distribution of gas. Sasol expressed interest in marketing natural gas from future sources.

1.50 Gas transmission and distribution are naturally monopolistic, but gas supply can be competitive. Even at this stage in the Gauteng area, potential for competition exists between coal-bed methane, Pande gas, and Gaskor gas. If a monopoly gas transmission company is set up, its business success should depend on how well it transmits—and possibly sells—gas. It should not also be trying to optimize other separate and distinct businesses, especially when these involve subsidies whose future is uncertain. Many companies indicated their concern that to allow this sort of structure to evolve is to perpetuate unnecessary and unwanted distortions in the gas business.

1.51 Two steps can be taken to improve the situation. First, any product sold or transferred by the synfuels business to another operating arm of Sasol must be at a true arms'-length price. This should apply particularly to gas sold by Sasol to the gas transmission business. Clearly, an acceptable contract for purchase of Sasol gas would have to form part of the terms of separation, and that could be difficult to draw up. Volume and duration would have to be agreed, and an arms'-length price would have to be determined. Second, and as a corollary, gas production, transmission, and marketing

should be operated as separate businesses. Ideally, these should be under separate ownership, but if they are not, regulatory oversight will be needed to prevent an abuse of monopoly position.

Decontrol of Liquid Fuels

1.52 It is likely that liquid fuel prices would adjust somewhat if the oil industry were decontrolled, as is being discussed at present. The current price regulation in South Africa provides for the same price to all producers/refiners whether they are conventional crude oil refineries or synfuels producers. Among the liquid fuels, heavy oil is the main competitor with gas. New entrants to the South African gas market will therefore face uncertainty about deregulation of liquid fuel prices and the future shape of the oil industry.

The Future of Mossel Bay Gas

1.53 Two schools of thought are current on the question of whether putting Mossel Bay gas into the Cape market would help or hinder the development of Kudu gas. On the one hand, it is argued that the entry of Mossel Bay gas would help develop the market for Kudu. On the other hand, it is suggested that the Mossel Bay supplies would absorb a significant market volume for some time, making it difficult for Kudu to achieve critical sales volume. Clearly, how the issue of Mossgas is resolved is vital to the future of the gas industry in the Cape. For example, if Mossgas is converted to a conventional refinery with government money and without full regard to commerciality, this would further distort the refining industry. Several options for continuing with the Mossgas operations or otherwise are being studied at the moment. The best solution is to create a level playing field for gas supply to the Cape. Toward that end, the terms for potential supply of gas from Mossel Bay to Cape Town should be transparent.

2

Structural and Regulatory Options

Existing Legal and Regulatory Framework

2.1 Apart from licensing exploration and legislating on taxation, the government of South Africa exerts no national legal or regulatory control over the gas industry as such. Naturally, environmental legislation and general industrial legislation such as the occupational safety and health act apply to the downstream gas industry. Excise regulations also stipulate annual calibration of gas meters. One quirk of the existing taxation system, as previously noted, is that pipelines are regarded as permanent infrastructure, and no allowance is made for their depreciation.

2.2 Essentially the downstream industry is self-regulated. For example, Gaskor's pipework is either in steel—complying with the American ANSI 312B standard —or HDPE plastic, which conforms to British Gas codes. These are self-imposed standards; the whole operation is in fact self-regulated. Gaskor has imposed an ISO 9002 audit requirement on itself, and has formal, internal environmental procedures. It conducted an EIA on its new line to Witbank. Annual meter calibration is required by the government's excise department. Cape Gas operates on an older set of technical standards. This lack of specific control of the gas industry does not appear to have caused problems at the current scale of the industry, but a more formal legislative framework seems inescapable if the industry is to grow significantly. Petronet, the oil pipeline company is also self-regulated.

2.3 Exploration and production of all minerals, including petroleum, are regulated by the Minerals Act of 1991. This situation contrasts with that of most other countries, where petroleum activities are controlled under separate legislation. Today, most of the offshore exploration area is leased (OP 26) to Soekor, which is currently trying to attract foreign and domestic companies to explore this acreage. In contrast, the mineral rights onshore are held by individual owners of these rights. As a result, substantial and significant differences can now be found between the onshore and offshore regimes for oil and gas. For example, ring fencing of fields is an issue onshore but not offshore, and leasing procedures offshore have clear terms; that is not always the case onshore. Suggestions were made by several companies to harmonize the onshore

licensing provisions with those offshore and to prepare separate legislation to regulate petroleum activities in the country. This is the case in most other countries, where a Petroleum Law or a Hydrocarbon Law allows the government to make special provisions to capture the unique features of petroleum. Returning rights to hydrocarbons to state ownership would simplify the licensing, but the government would then have to revoke rights to property granted by the 1991 Minerals Act.

2.4 In principle, mineral rights in South Africa belong to the owners of the land under which the minerals occur, although the rights have often been separated from the current owners of the land and now belong to someone else. Private individuals thus own the rights in many cases. Still, large tracts of land remain in the hands of the government, and all offshore rights rest with government through a lease (OP 26) to Soekor. Those wishing to explore for and develop minerals thus must first negotiate with the mineral rights owner and then obtain prospecting and eventually mining licenses from the state.

2.5 In practice, the situation offshore is quite clear. Soekor has been granted the right to prospect for oil and gas over the majority of the offshore acreage. It has the right to grant subleases and organized a licensing round in 1994. Soekor as owner of the head lease is proposing to levy a royalty on production on a sliding scale between 2 and 5 percent. It also reserves a right to participate up to 20 percent in successful discoveries.

2.6 This is in addition to the general taxation provisions, which impose basic company tax at 35 percent plus a special tax on oil and gas production at the following maximum rates (these are reduced by 50 percent for the first two leases granted in water deeper than 200 meters):

- Until cumulative profit (i.e., taxable income) equals investment, 20 percent
- Thereafter, until profits reach double the investment, 30 percent
- Thereafter, 40 percent.

This set of provisions gives effective tax rates of 48 percent, 54.5 percent, and 61 percent (excluding royalty) for these three bands. The minister of finance, in consultation with the minister of mineral and energy affairs, has the power to waive all or part of the oil and gas tax.

2.7 Because the Soekor lease incorporates the taxation terms as they stood in 1977, there is no ring fencing of income from oil and gas development, and costs may be offset against income from other sources in South Africa. This may also give protection from secondary company tax (which did not exist in 1977 and is currently levied at 25 percent on dividend distribution), but Soekor believes that it probably will not.

2.8 From an explorer's point of view, the situation onshore is far less clear. Soekor has surrendered its corresponding lease to onshore acreage (primarily because it sees very little potential for onshore exploration for oil and natural gas). This does affect coal-bed methane, however, as well as natural gas. The result is that the procedures for

obtaining onshore leases, and the terms applying to them, are very different than they are offshore.

2.9 Terms would have to be negotiated with individual owners of mineral rights, and in this case clearly would not involve licensing rounds with standard terms. Taxation is in principle the same as for offshore development, but current rather than 1977 terms apply. The major difference is that current terms "ring fence" the income from each separate mine (or gas field) so that costs cannot be offset against other income from other fields or other business in South Africa. For any company that has other profitable activities in the country (and many of the major exploration companies do), such terms represent a significant business limitation.

2.10 Rights for different minerals can be granted separately. For example, rights to explore for and develop gas can be granted separately from rights to mine for coal, but no established right of priority exists between a company wishing to mine coal and another wishing to recover coal-bed methane. Clearly, a company interested in coal-bed methane faces a significant negotiation in such circumstances, as it first will have to gain rights from the owner of the mineral rights and then negotiate with any other entity that has rights to mine any other mineral (such as coal) in the same area over how the two companies should operate. Moreover, prospecting and production licenses still have to be obtained from the government.

2.11 The government could intervene in the national interest to resolve intractable disputes. The Mineral Act allows an entity that is mining for one specific mineral also to mine and dispose of any other mineral if joined production of the two minerals is necessary. If no agreement can be reached with the holder of the right to the other mineral, the provisions of the Arbitration Act will apply. Before issuing a mining authorization, the government also scrutinizes the question of optimal exploitation. The government also has the power to intervene after authorization has been issued and to order rectifying steps if a mineral is not being mined optimally.

2.12 The mission recommends that the government should evaluate the fiscal onshore regime, with particular emphasis on coal-bed methane. In other countries, viable commercial production of coal-bed methane has required some fiscal incentive (compared with natural gas). In South Africa, it is at a disadvantage compared with offshore gas. The difference lies primarily in the requirement to ring fence onshore income, and the removal of this provision would harmonize offshore and onshore exploitation and could be sufficient incentive on its own. The concern about the precedent value of such a provision for other minerals is understandable. However, oil and gas are subject to special petroleum taxes, and exploration and production of oil and gas are sufficiently different from hard minerals to fall under separate legislation. This would provide a solution to such issues as underground capture and would allow treating hydrocarbons differently from other minerals without creating unfortunate precedents.

Downstream Regulation

2.13 The inherent monopolistic characteristics of transport and distribution in natural gas business, coupled with a tendency to seek vertical integration to protect the very high up-front capital investments, result in a highly concentrated and monopolistic structure at the time of startup of the business in most countries. Upstream competition between resource owners usually emerges fairly quickly, as the market develops. Although the reasons for how gas businesses have developed are reasonably well understood, the monopolistic structures are still a cause for concern in many countries. The issue is that, in a mature business, vertically integrated monopolies do not work wholly in the public interest and are not essential to the continuance of a healthy gas industry.

2.14 Such concerns have prompted a number of countries to undertake reform of their gas businesses, although the process is not complete anywhere. Two major tools are used to some degree by every country that has attempted reform. The first is the introduction of competition; the second is the regulation of monopolistic behavior. The World Bank usually favors competition over regulation. Market mechanisms and the possibility of business failure are widely recognized as the best way of ensuring the most appropriate allocation of resources and the quickest adaptation to changing market conditions. Competition is also self-regulating and hence does not require outside intervention.

2.15 In the case of a natural monopoly in gas transportation and distribution, it is virtually impossible to introduce any real level of competition, as duplication of pipeline systems is often a very inefficient use of resources. Here, external regulation is basically the only way to limit the abuse of the monopoly. The main problem with regulation is that it is not self-adjusting, and distortions may be introduced as a result of regulation. In addition, the process is bureaucratic and can be costly to administer. Governments have searched for methods of regulation that try to mimic the effects of competition in order to give the regulated bodies incentives similar to what they would experience in the marketplace in an attempt to reduce regulatory distortions. Governments have also sought to make regulation simpler and less costly. These two motives are not necessarily compatible.

2.16 In most countries that have attempted reform, the focus has been on promoting gas-to-gas competition. Generally several gas producers supply the transmission and distribution system, and invariably the market consists of many final customers. Competition thus is primarily a matter of allowing the gas producers to compete with each other to supply the customers. The main vehicle is to allow suppliers and customers "open access" (also known as third-party access; TPA) to the monopoly transport systems. This allows interested parties to move gas through the transmission and distribution system, at least to the extent that it has spare capacity, and therefore puts suppliers and customers in a position to deal with each other directly.

2.17 Ironically, this supplier-to-customer market interface is achieved through regulation—that is, regulation of the intermediary transmission network. In the open-access framework, the transmission company is required, first, to offer spare capacity to third-party suppliers and, second, to charge them a regulated and nondiscriminatory tariff.

2.18 Vertical integration can be an obstacle to the introduction of competition between gas suppliers. Where gas transmission and distribution are responsibilities of a vertically integrated company, providing for open access is not necessarily enough to encourage third parties to compete. In this case, the market power of the gas utility may be so great that new gas marketers would be at a considerable disadvantage and would generally need a degree of protection from competition until they have built up enough market share to counteract the market influence of the incumbent utility. Although it is most common to find integration between transmission, distribution, and marketing, the problem is similar if production and transmission are vertically integrated; it becomes very difficult for a new producer to market gas even though the producer can gain access to the transmission system.

2.19 The problem of vertical integration of a utility as a barrier to competition and market entry can be approached in several ways. The most radical tactic is to require the monopoly utility to divest an aspect of its operations (e.g., its marketing activities) into a wholly separate, unaffiliated company. A second option would be to put marketing operations into a separate subsidiary with fully transparent accounting and with management separated from that of the transmission arm. The regulatory agency would be empowered to ensure that the two companies were genuinely operated at arms' length. A third alternative would be to restrain the marketing arm's ability to compete—for example, by requiring it to publish price schedules—until the new entries have established sufficient market shares.

2.20 Downstream regulation has two main objectives. The first is control of prices and tariffs to check the abuse of monopoly, which has the greatest tendency to arise in pipeline distribution, where the natural monopoly element is hard to avoid. It is also used to protect small customers, who—once they have invested in equipment to burn gas—essentially become captive customers of the gas utility. In some countries, promotion of competition is sought as a second objective. Regulators in the United Kingdom and Argentina have been given a statutory duty to further the development of competition in the gas sector.

2.21 In essence, two main forms of price regulation are in current use: *rate-of-return regulation* and *price-cap regulation.* In addition, a move to make regulation more market responsive is in progress under the rubric *incentive regulation.* Price-cap regulation is in fact a particularly well-developed form of incentive regulation.

2.22 The original form of gas pipeline regulation, which originated in the United States, was rate-of-return regulation. The other methods have been devised as ways to overcome some of the acknowledged disadvantages of the rate-of-return method.

Rate of Return

2.23 The key features of rate-of-return regulation—which is widely used in North America—are as follows:

- The regulated company files a tariff proposal, and for an agreed test period the company calculates costs, capital employed, and cost of capital.
- The regulatory commission determines a fair maximum rate of return on capital employed.
- The total revenue requirement of the pipeline is calculated based on these data and assumptions about the future business.
- This determines the level of the tariff, which is then split among tariff elements.

2.24 The structure of the tariff has to avoid unfairness or unreasonable discrimination. The tariff, therefore, must be approved on a service-by-service basis, which typically requires the allocation of common costs on the company's services.

2.25 The two main problems with rate-of-return regulation are that it becomes extremely complex to administer on a large, developed system and that it encourages overinvestment. The return an operator can make on assets is limited by the regulation, therefore the only way the investor can increase profit is by making more investment. This encourages "goldplating" and is a disincentive to efficiency. In its pure form, the system also shelters the operator from the risk of business failure. If business falls off, the tariff is raised to generate the same rate of return. This is clearly opposite to the way a market would respond. No price risk is taken. Normally, this is overcome by only allowing the operator the permitted return at a defined level of throughput. This is already a move toward incentive regulation.

Price Cap

2.26 The key feature of this form of price control is that, for a specified period (four to five years), the company can make any changes it wishes to prices, provided that the average price does not increase faster than the cap (or maximum price). This cap is usually determined by the rate of inflation minus an efficiency factor, specified initially by the government. In the U.K., price-cap regulation was originally introduced on non-gas costs for gas distribution. Transmission costs were also regulated, while the utility was allowed to pass through the full purchase cost of the gas until recently. However, the regulator went a step further by modifying the formula and placing limits on the pass-through of gas cost. Since the separation of British Gas' transportation business from other operations, this part of the business has been subject to a price-cap regulation.[2]

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2. See Beesley and Littlechild, "The Regulation of Privatized Monopolies in the United Kingdom," *RAND Journal of Economics* 20 (Autumn 1989).

2.27 Some of the pros and cons of price-cap regulation are discussed below.

2.28 The advantages are as follows:

- Price-cap regulation is less likely than a rate-of-return or a traditional cost-plus approach to lead to "gold plating" and overinvestment. Because it allows the regulated company to keep whatever profits it can earn during the specified period (and requires it to absorb any losses), price-cap regulation preserves similar incentives to normal profit maximization. The efficiency factor element forces part of the efficiency gain to be passed onto the customers. Prices therefore should be lower than they would be under rate-of-return regulation.
- Price-cap regulation allows the company greater flexibility to adjust prices within the cap. In the United Kingdom, price caps were introduced for gas, electricity, water, and telecoms, and their prices were believed not to reflect the real costs of service. The cost structures were not well understood, however, when the regulation was put in place. It follows that efficiency factor was set totally empirically. Most of the regulators have been able to increase the efficiency factor well above the initial targets, as the regulated utilities have been able to make major gains in productivity. This is perhaps some indication of the level of inefficiency in the state sector.
- Price-cap regulation is simpler to operate by the regulator and the company. It requires less full-time staff to regulate. The largest need for analysis arises prior to the adjustment of the price-cap (e.g., every four to five years) and could be contracted out by the regulator. Because it is more transparent and better focused on the issue of primary concern to customers, it is also more reassuring.

2.29 The disadvantages are as follows:

- Criteria for setting and resetting the efficiency factor may not be clear and may undermine the incentive element. To set the efficiency factor in an analytical way requires many of the same considerations as for rate-of-return regulation. If increasing efficiency results in a much tougher efficiency factor, and if the efficiency factor is changed before the expiration of the set period, then price-cap regulation is only a special form of rate-of-return regulation.
- Flexibility of pricing is also criticized for allowing cross-subsidization, which can be used anti-competitively.
- Reduction of the price cap or increase in the efficiency factor carries a risk for the investor (and a lower rate of return in rate-of-return regulation). Several elements of the system, however, could form a useful part of rate setting anywhere.

2.30 Price-cap regulation of the downstream gas chain is of greatest value for newly privatized companies where significant productivity gains can be made, and significant room exists for bargaining between regulator and regulated. For a greenfield project, such as a new gas pipeline, the price cap would be calculated based on the planned investment costs, assumptions about future business, and an allowed rate of

return. The approach would thus be similar to the rate-of-return regulation. The differences relate to how to determine the price cap based on planned investment and operating costs for the pipeline and how often and how quickly the efficiency factor is changed.

Incentive Regulation

2.31 The United States is experimenting with another method of providing productivity incentives to transmission companies and reducing the need for intervention by the regulatory commission. The longer the time between tariff filings, the greater the likelihood that transmission companies will profit from innovative and cost-saving measures. The alternative now emerging in the U.S. gas industry is to index tariffs to both inflation and transmission industry productivity. This "benchmark regulation" rewards those who beat the industry productivity average and relies heavily on comparisons of performance between one pipeline operator and another. Regulators in other countries are using the same method to establish benchmarks or "yardsticks" for electricity and water utilities. Unfortunately, benchmark regulation in the gas sector is likely to be limited to North America, which is the only area with a large number of gas transmission pipeline operators for comparison.

Regulatory Practices Around the World

2.32 This section describes and draws lessons from a number of gas industry structures and their regulation around the world. First, the established structures in the mature markets of the United States and Europe are described; these show alternative approaches to the gas industry regulation. Then, the example of Portugal, which is bringing gas to its market for the first time, is discussed. Last, the reforms being considered in many mature markets are summarized. The reforms have been introduced to combat the problems arising from the way in which the market was structured in the first place.

Mature Markets: The United States and Europe

2.33 **The United States.** For all its problems in the 1970s and 1980s, the United States is now the closest to a fully competitive market and is the prime example of an unbundled gas market. Producers, transporters, and distributors are all separated, and transporters are being required to give up their old merchant function or separate them into affiliated businesses. Most contracts are short term. The Federal Energy Regulatory Commission (FERC) controls tariffs on interstate pipelines and exerts a strong element of control (and has a large staff to carry out its duties). Tariffs are set primarily on a rate-of-return basis, but more and more incentive elements are being introduced. Access to interstate pipelines is operated on a first-come, first-serve basis. FERC is financed by the industries being regulated. For natural gas, the regulatory charges are based on throughput in pipelines.

2.34 It is important to understand that all of the conditions for a competitive market are largely present in the United States: gas producers number in the tens of thousands; the pipeline network is highly developed, which means more than one pipeline may be available on many routes; and the market is highly diverse and includes many local distribution companies and individual buyers of substance. As in most other gas markets, the gas trade in the United States used to be based on long-term take-or-pay sales contracts operating over fixed periods. Regulation (which included complicated wellhead price regulation) tended to distort the market, first generating a shortage of gas and then overcompensating and generating a surplus. Wellhead prices are now set by gas-to-gas competition, and the price of competing fuels is less relevant.

2.35 In summary, the U.S. market has become liberalized as the result of a particular set of circumstances. It is still evolving and has probably not reached its final form. It would not be possible to use the U.S. situation as a model for an emerging market that initially has only one field and only one delivery pipeline. The difficulties of the complex regulation involved are also grounds for caution. Certainly, however, new markets can draw some lessons from the experience of United States—for example, with regard to the benefits of "open access" pipelines. Still, most gas markets will not be able to achieve the highly competitive market structure in the United States, even in the long term.

2.36 **Europe.** The characteristic structure of the gas industry in Europe is for a handful of competing suppliers to sell to large monopolistic transportation (often also distribution) companies on long-term take-or-pay contracts. These companies sell to end users. Many of the gas transportation and distribution companies are state owned and are subject to some degree of price control, particularly in domestic markets. Germany, where the transportation companies are not state owned and no price controls are applied, is the major exception. In practice, however, gas prices throughout Europe are close to competing-fuel prices, so actual price control is very light.

2.37 Attempts are being made in Europe to liberalize and unbundle gas markets. These efforts arise from a concern about the efficiency of the major utility companies and their ability to take monopoly rents, tempered only by the price of competing fuels. In continental Europe, enormous resistance has arisen against liberalization from those with a vested interest in the monopolies. The resistance is presented in terms of concern for security of supply. Gas supplies to Europe come in much larger parcels than in the United States and at higher cost. They are either offshore or imported over substantial distances, as in the case of Russian supplies. Great concern has developed therefore about undermining the long-term take-or-pay contracts that underpin the financing of these developments, and on which future supplies are seen to depend. Only the United Kingdom (see below) and Romania have introduced regulators at arms' length from government control.

A Developing Gas Market: Portugal

2.38 A useful approach for introducing natural gas that is reasonably suitable for less wealthy countries has been tried in Portugal. It provides a good example of pitfalls, too. The model here is to have a national transportation company responsible for obtaining gas supplies from abroad (Algeria). A major trunkline is to be built by the company running from the import point northward up almost the full length of the country to Brage. The transmission company will supply four regional distribution companies that will sell gas within defined geographical areas. The transportation company may supply directly any customer taking 2 million cubic meters per year (mcmy) or more. In practice, the early market will be driven by gas demand for electricity generation, and the power company will receive its gas supplies directly from the transportation company.

2.39 Portugal invited international tenders for participation in both the transportation and distribution companies. No proportion of Portuguese ownership was required. However, in the case of the transportation company the Portuguese state reserved for itself a "golden share" of up to 10 percent of the company—this golden share granted the state a certain number of rights such as veto on the transfer of shares. The bidders were required to propose appropriate technical and commercial structures for the project, and the bids offered different pipeline routings, storage configurations, methods of financing, and so on. The winner would be responsible for negotiating gas supplies from Algeria. This method achieved a useful injection of outside funding and creative input at no cost to the government, and it secured a substantial role for Portuguese companies and European Union funding. Bids were called for three of the four regional distribution companies at the same time as for the transportation company, but the awards were made later. In the fourth area, Lisbon, there was no tender; the concession was granted to Gaz do Portugal, the existing town gas distributor. In this case, a majority Portuguese ownership was required, and a position was reserved in the Lisbon distributor for Gaz do Portugal, the existing town gas distributor. In all cases, the winning bidders were granted 35-year franchises.

2.40 Unfortunately, the process ran into difficulties. It was originally intended that gas should be imported as LNG through a new terminal to be built at Setubal. Although contracts were agreed with the Algerians, no agreement had been reached with the anchor customers, the power utilities. This has caused a delay in implementation, and now (after renegotiation with the Algerians) gas is planned to be piped in via Spain. In the meantime, however, the transportation consortium has disintegrated. Because the Algerian gas price was set at the Algerian border, Portugal faced having to negotiate a tariff with an unregulated monopoly pipeline system. This problem was resolved by creating an import company, Transgas, the majority of which was owned by state-owned companies. Transgas took an ownership stake in all the supply systems up to Portuguese border—in the Gasoduc Mahgreb-Europe (GME), the company that transports the gas from the middle of the straight of Gibraltar up to Cordoba and also in the company that

transports the gas from Cordoba to the Portuguese border. The system is under construction, according to planning, and the system is due to start commercial operation in early 1997.

Reform of Industry Structures in Mature Markets: The U.K., Argentina, and Australia

2.41 Most gas industries grew, as did those in Portugal, with transmission and distribution systems that were to a large extent monopolistic. It is hard to create a viable gas industry without granting the initial investors some protection from competition. However, as their gas industries mature, more and more countries are finding their monopolistic structures no longer satisfactory and are seeking to reform them by reducing state involvement and letting in more gas to gas competition.

2.42 **The United Kingdom.** The United Kingdom has been the chief proponent in Europe of increased competition, but the country has also been concerned to retain long-term contracts and to continue to encourage the development of its North Sea gas reserves. The reform process was initiated by the privatization of British Gas, the formerly state-owned gas transmission and distribution monopoly. It was privatized without any restructuring and overnight became a private, vertically integrated monopoly, albeit a regulated one. The main role of the regulator was to control domestic prices using the newly devised price-cap method. However, the industrial market was opened to competition, and the regulator placed a series of controls on British Gas to ensure that others could gain entry to the market. Larger and larger segments of the market have been progressively opened up as the threshold size of customers at which competition is permitted has been progressively reduced. A number of new marketers have emerged to compete with British Gas. So far, this competition has been highly dependent for its existence on regulation of British Gas' activities.

2.43 In general, the U.K. preference has been for competition over regulation in the reform of the gas sector, but regulation clearly was essential to bring about change. Regulation is unlikely to be abandoned in the United Kingdom even in the long term, as no prospects appear to be developing for significant competition in the transportation system. As the market has been opened up further and the complexities of access to all the services provided by the transmission company have been realized, the regulator's role has expanded considerably. As it is now proposed to allow free competition to supply even domestic customers, the regulator is also developing license terms, with which anyone wishing to supply the domestic market will have to comply.

2.44 **Argentina.** Natural gas accounts for about 40 percent of primary energy in Argentina. Until 1991, production was in the hands of the state company, YPF, and transmission and distribution were carried out by another state monopoly, Gaz del Estado (GdE). By the late 1980s, GdE was in a poor financial state. The government therefore decided (in 1991) to take radical action to privatize both GdE and YPF (as part of a wider privatization and macroeconomic reform program). To generate a more competitive industry, GdE was restructured into two transportation companies and eight regional

distribution companies. The transportation companies were granted 35-year licenses, renewable for an additional 10 years, and the distribution companies were given exclusive rights to distribute within an area. All firm transportation capacity was allocated among the eight distribution companies on 10-year take-or-pay contracts. Open access was to be allowed so that producers and consumers as well as distributors have access to the pipeline system, provided that capacity is available. Under certain conditions, and on giving six months' notice, large consumers (of more than 3 mcmy) may bypass the distribution companies and obtain gas directly from producers.

2.45 A Gas Act was passed that provided for the sale of the assets of GdE to private companies, the conditions governing the licenses to operate such assets, and the conditions governing exports and imports. The act also set up the regulatory framework for the gas industry after privatization. A regulatory body, Enargas, was set up with a budget funded from fees paid by each of the regulated companies. Price-cap regulation has been introduced. A key element is that producers, providers of storage, traders, or consumers are not allowed to own a controlling interest in either a transportation company or a distribution company. Similarly, a transportation company cannot control a distributor and vice versa. To introduce competition in the marketplace, both transportation companies were given access to the largest gas basin in the country and to Buenos Aires, the largest gas market. In addition, the government divided the city of Buenos Aires so that it is served by two distributors.

2.46 The rights to these companies were put out to tender. A condition of the tenders was that each bidder should include a technical operator with previous experience (effectively outside Argentina) that had to hold a minimum threshold shareholding for at least eight years. An Argentinean company also had to be included in each bid. A wide spectrum of bidders was attracted, and the winning groups included Enron from the U.S., Nova Corp. from Canada, British Gas from the United Kingdom, Gas Natural from Spain, Camuzzi and Italgas from Italy, and Tractebel from Belgium.

2.47 Gas supply is still dominated by YPF, which still controls something like 60 percent of supplies. This state of affairs arises because most of YPF's upstream gas reserves were retained by the newly privatized company. On the whole, however, the transition has been managed successfully, and the industry is now profitable. The dominant supply position of YPF and its price leadership give some cause for concern. The new distribution companies have 10 years' reservation of transportation capacity, and the rights of bypass are limited.

2.48 **Australia.** The gas industry in Australia has grown up on a state-by-state basis, and in only one case is interstate trade conducted. Efforts have been made recently to pull all these state industries together into a national policy framework. Gas industry reform is part of a widespread movement within Australia toward macroeconomic reform. The major steps have been the publication of the Hilmer committee on competition policy, which contains a chapter on the structural reform of public monopolies, and most recently an initiative taken by the Council of Australian

Governments (COAG). These two reports attempt to define a national framework within which reform in individual states can take place and impediments to interstate trade could be overcome.[3]

2.49 The Hilmer committee's most significant recommendations are as follows: (a) Before competition is introduced to a sector traditionally supplied by a public monopoly, any responsibilities for industry regulation should be removed from the incumbent. (b) Where the natural monopoly element is vertically integrated with potentially competitive activities, a presumption should be made in favor of separation at the ownership or control level.

2.50 The COAG committee looked at the Hilmer proposals in more detail in the specific context of the gas industry. The committee's recommendations include removal of all remaining legislative and regulatory barriers to the free trade of gas, both within and across state boundaries, and implementation of a uniform national framework applied to third-party access to all gas transmission pipelines. Moreover, the committee commented that open-ended exclusive franchises are inconsistent with the principles of open access and that more competitive franchise arrangements should be introduced. The committee suggested that the granting of exclusive franchises should not impede the ability of large users to deal directly with gas producers. Finally, it recommended introduction of uniform national standards for construction of pipelines.

3. Independent Committee of Enquiry into National Competition Policy, *Hilmer Report*, chapter 10, "Structural Reform of Public Monopolies" (Australian Government Publishing Service, August 1993). Council of Australian Governments (COAG), *Progress to a Pro-Competitive Framework for the Natural Gas Industry Within and Between Jurisdictions*. Report by Officials to Heads of Government (February 1994).

3

Recommendations for South Africa

3.1 For a number of reasons, it is not easy to devise a fully satisfactory and easily implemented structure for the gas industry in South Africa. To begin with, the present gas industry in the country does not form a very good basis from which to build a well-structured natural gas business; moreover, the timing and viability of natural gas developments in the country and in the region are uncertain. Finally, the existence of the Sasol/Gaskor network and the distribution systems of JWGD and Cape Gas constrains the establishment of new transmission and distribution utilities and the level at which transmission and distribution are separated (these systems do, however, provide a gas market and a basis for developing and expanding a natural gas industry in South Africa).

3.2 Whatever the difficulties, a consideration of paramount importance is for the sector to avoid hindering the development of projects by private industry and, if possible, to encourage that process. The implication of the foregoing is that development of the gas sector can transpire without requiring the state to use its limited capital resources to develop the gas business or to set up a national gas company to promote the introduction and marketing of natural gas into South Africa. It is clear that private domestic industry and international gas companies are both willing and able to develop gas production and transmit and distribute gas within South Africa; their entry into the market would promote the most efficient use of resources.

3.3 It is equally clear that private interests will only develop gas to the extent that it is commercially viable. Their full participation thus is likely only if the government succeeds in establishing a rational structure for the business as a whole and in particular in establishing controls over the industry's monopolistic elements.

Structure of the Gas Chain

3.4 The following discussion of options for the South African gas industry is based on several assumptions about the structure of the gas chain, as explained below. Most upstream companies would prefer to concentrate on finding and developing fields and transporting the gas to the main transmission system. They generally do not wish to be involved in transmission and distribution, although they would contemplate it if it was

essential to bring the gas to market. It is desirable that the gas producer should have the capability to make direct sales to major customers in order to create some competition between suppliers of gas.

3.5 Transmission takes gas from the producers and moves it to major distribution centers in large, high-pressure pipelines. The transmitter may itself sell to large industrial customers and local distribution companies, which take gas directly from the high-pressure system ("merchant pipeline"), or it may act purely as a transporter, carrying gas for a tariff ("open-access pipeline"). Pipelines are an inherent monopoly, and the main challenge in developing a structure is to provide acceptable control of the monopoly while providing an attractive commercial opportunity for attracting investment.

3.6 Vertical integration should be kept at a minimum, and production, transmission, and distribution should be separated as far as is practicable to encourage transparent transfer pricing and an appropriate allocation of resources between the three functions. The natural monopoly characteristics of gas transmission, in combination with a vertical monopoly, would give the company incentives to use the available transmission capacity for own production, to restrict access for competitors, and not to increase capacity when needed by competitors. However, operational and administrative savings and reduced transaction costs can be achieved through vertical integration. For some of the supply sources discussed in chapter 2, it seems highly possible that, to find buyers, gas producers may need to build significant lengths of delivery pipeline to bring gas either to a large customer or to a transmission/distribution system. If open access is provided for potential additional capacity in excess of the original capacity based on one or two "anchor" customers, vertical integration should be acceptable for the startup volumes, particularly as the alternative may be no project. For incremental volumes, however, open access should be provided, and the regulatory framework for this should be agreed before the project starts. The regulation should include a separation of the production, marketing, and pipeline operations of the company, including a transport agreement between the two parts of the project. Moreover, the regulatory agency would need to be satisfied that such arrangements were at arms' length and that third-party users for additional capacity were not subject to discrimination.

3.7 The regulation may be further complicated by the fact that for some of the supply sources discussed in chapter 2, gas is imported (i.e., production and transmission to the border are under the jurisdiction of a foreign country). The South African government cannot control that structure. Therefore, production and transmission should be regarded as one element of the gas chain. The government of South Africa can only regulate transmission from the border and distribution of gas within South Africa.

3.8 Distribution is the retail element of the system, taking gas at a number of citygate points from the transmission system and distributing it at lower pressure to a large number of smaller customers, usually through an extensive network of piping. To provide a stable supply and allow the distributor to buy sizable parcels of gas on long-

term contract, the distributor generally will require a limited regional monopoly. In some countries, large customers are allowed to "bypass" the distributor (i.e., purchase directly from the producer or transmitter of gas). The gas can reach the customer in two ways: (a) the gas can be transported over the distribution network for an agreed transportation fee through open access on the distribution network; or (b) the producer or customer can build a pipeline directly to major customers, if this is allowed in the legislation ("physical bypass"). No strict rules govern where transmission ends and distribution begins, particularly in South Africa, where the small consumers in industrial, commercial, and domestic markets (the mainstays of most distribution systems) tend to be comparatively small, and large industry is the dominant market. A clear legislative definition of the boundary between transmission and distribution is important, however, to clarify the extent of bypass and monopoly in each element of the gas chain. It is recommended to define a large threshold for bypass so that distributors have a basis for aggregation of demand.

3.9 In the following options, open access on the distribution network is recommended—if access is open to the transmission network. Otherwise, if producers cannot reach the customers, gas-to-gas competition would not be achieved unless producers or consumers constructed physical bypasses. The distribution company would have an interest in moving gas on an open-access basis rather than risking a physical bypass. It has to be recognized that competition through open access would give the producers an opportunity to supply gas to the best customers ("cherry picking"), thereby undermining the distribution company's ability to act as an aggregator of demand in its distribution area and to enter into long-term contracts with suppliers for purchase of gas to these customers. However, the distribution company would still earn income from the transport part of the business. If, however, the risk is still deemed high, the distribution company could be compensated in three ways: (a) for newly constructed distribution networks, bypasses would not be introduced for the first five to seven years; (b) a large threshold could be set for bypasses for a period of five to seven years, then lowered; or (c) a higher rate of return is allowed than for transmission companies.

3.10 No separate gas storage function exists yet. Most mature gas businesses have elements of storage and load management in each function; field output varies somewhat in response to demand; the transmission system usually has the bulk of underground storage facilities to manage seasonal demand swings; and distribution often has low-pressure storage to cover diurnal variations in offtake and interruptible customers who can be cut off in periods of peak demand. This allows an element of choice and competition for the cheapest way to provide a load management service without forcing it to be unbundled. No restriction should be placed on anyone who wishes to build separate storage facilities.

Structural Alternatives for South Africa

3.11 As noted above, gas developments have certain characteristics that make them particularly vulnerable. They are very capital intensive and require a substantial

scale to be economic. Gas is expensive, and options for transport are not flexible. Often, only a single customer (often a state monopoly) has the bulk of demand for the gas, or the development depends on a few very large customers. The gas developer makes virtually the whole of its investment before a cubic meter of gas flows and before receiving any income. These considerations are taken into account in the following three alternative structural options. The first option is the "merchant pipeline," the conventional way of developing new gas industries. It would be the easiest to implement. The second is for "open access," which aims at reducing or eliminating the problems of monopoly that are likely to require restructuring the industry in the future. The last—and recommended—choice would be a hybrid of the merchant and open-access options.

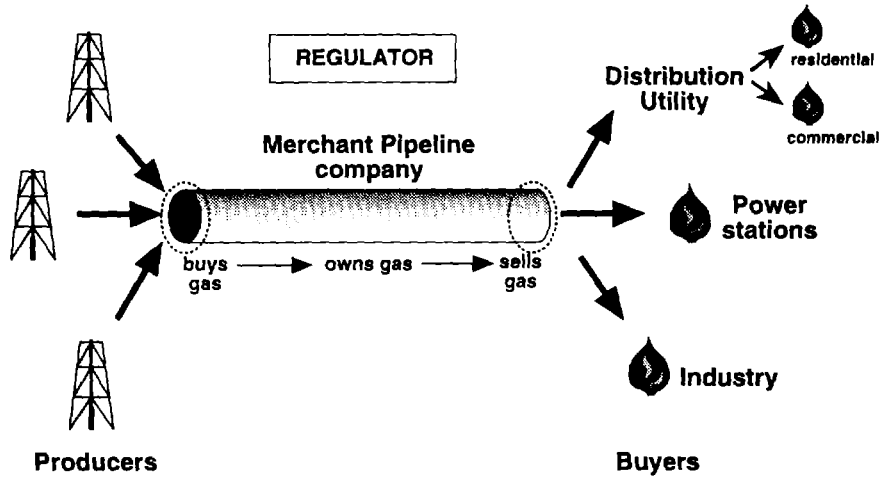
3.12 One element that runs through all three options and is an integral part of them is that the government should evaluate different proposals for the transmission and, desirably, the distribution of gas. This approach has numerous advantages. It is the best way to test the private sector's interest in the business. It can reduce the need for regulation substantially in the early years, as the government can be confident that the terms are competitive. Moreover, the approval can be carried out to allow the project developers to make an input to the detailed design of the industry structure, as they can be consulted in advance on the terms of the project evaluation and given a degree of latitude in proposing optimal pipeline locations, capacities, tariffs, and so on.

3.13 To understand the basis of the recommendation, it will be useful to examine some details of all three options—"Merchant Pipeline," "Open-Access Pipeline," and "Hybrid," as discussed below.

The Merchant Pipeline Option

3.14 The principal characteristic of the merchant pipeline arrangement is that the transmission company is allowed to buy gas from producers and sell gas to customers and is not required to transport gas for third parties. In effect, all customers, whether distribution companies or end users, must buy from the transmission company. Prices for the purchases of gas are negotiated between the transmission company and the producer, on the one hand, and between the transmission company and the customer, on the other. Because the transmission company owns the gas in its system and transports it on its own behalf, no transportation tariff is visible. It is desirable to have distribution companies to handle small customers, but in practice the transmission company could supply small buyers directly. The basic structure of the merchant pipeline option is illustrated in Box 3.1, and some additional characteristics are noted in Box 3.2.

Box 3.1 The Merchant Pipeline Option



Box 3.2 Additional Features of the Merchant Pipeline Option

Producers

- Sell to a transmission company on long-term take-or-pay contracts.

Upstream Regulation

- Licensing of acreage offshore is done by the host government, and onshore with the mineral rights owner. No price regulation takes place at the wellhead. Rather, the price is freely negotiated between the producers and the buyer (i.e., the transmission company).

Transmission/Distribution

- It is desirable to have separate distribution companies to supply small customers.
- The transmission company has a franchise area from the custody transfer point of the gas supply to one of the following distribution areas: Gauteng, Cape Town, or Natal.
- Franchises for transmission and distribution are awarded by the government based on an evaluation of proposals. A need may arise to protect the position of the existing transmission and distribution companies (e.g., by giving them a right to participate in their existing franchise areas).
- To put competitive pressure on the franchise holder to expand capacity, the transmission franchises would not be exclusive: Another transmission pipeline could be built if the company demonstrated to the government that the public would be better served by construction of a second system.
- No open access on transmission pipelines is allowed.

(box continues on the next page)

(Box 3.2 continued)

Ownership

- Preferably no producer or customer is allowed a controlling share in a transmission company, and producers should not control the distribution function. If this cannot be achieved, more regulation is required to check abuses of monopoly.

Regulation

- Distribution costs for gas supply to captive customers are price-capped, while gas purchase costs at the city gate are passed through to the consumer.
- Other commercial matters are regulated by the general anti-monopoly law.
- Technical, environmental, and operational regulation will apply.
- Criteria for extension of distribution network should be considered if separate distribution companies are not set up and transmission company supplies small customers directly.
- No price regulation is applied for end-user prices to large customers (i.e., major industries and power plants). Alternative fuel prices put a ceiling on gas price over the long term.

Economic Rent

- If competing fuel prices rise, the monopoly, because of its market power, could capture parts of the economic rent from upstream.

Pros and Cons of the Merchant Pipeline Option

3.15 It may be useful to note briefly some of the pros and cons of the merchant pipeline option. On the positive side are the following attributes.

- The merchant pipeline option is the simplest possible structure for the downstream gas industry.
- It probably would attract many private investors, as the restricted competition could provide for overnormal profit.
- This option best ensures security of supply.

3.16 However, several significant problems may arise with the merchant pipeline option:

- It may prove difficult under the merchant option to establish separate distribution companies.
- The monopoly established in two of the key phases of the gas chain requires promulgation and enforcement of anti-monopoly regulation.
- It would be difficult to determine the right level of regulation because true costs are not known.
- No potential exists for gas-to-gas competition.

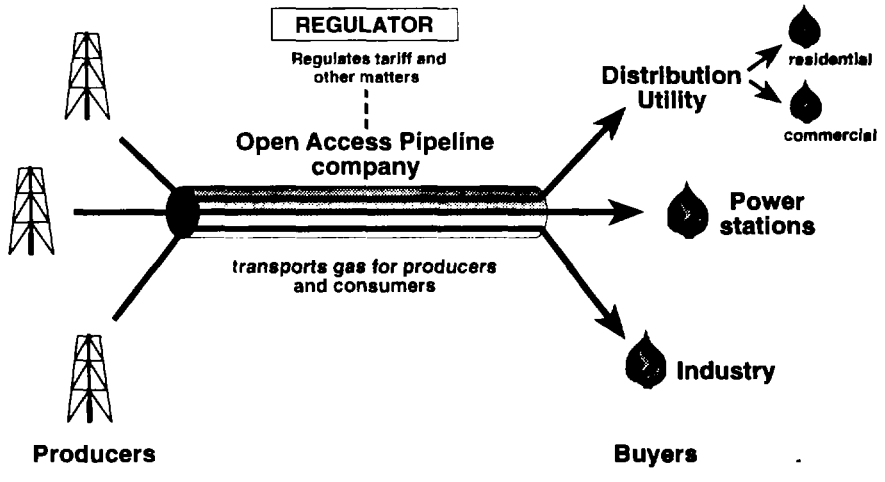
- Compared with other options, few market forces are in operation.
- Under this option, new producers could only sell their gas supplies to the transmission monopoly.

The Open-Access Pipeline Option

3.17 The main characteristics and structures of an open-access pipeline contrast starkly with the merchant option. In the open-access option, the transmission company is *not* allowed to buy and sell gas. Instead, it must transport gas for third parties on a nondiscriminatory basis. Producers thus sell directly to customers, and prices are set by direct negotiation between the producers and the customers. Concomitantly, the producers or the customers, not the transmission company, own the gas in the pipeline system.

3.18 In the open-access option, for transporting gas, the transmission company is allowed to charge a tariff that is regulated by an external regulatory agency. In this case, the need arises for a substantial distribution function covering the whole of the area served by the transmission company. Producers need to sell on long-term take-or-pay contracts, and these are only viable for large customers. It is also difficult for producers to deal with large numbers of customers. Rather, distribution companies with secure franchise areas are needed. These companies can offer long-term contracts to producers and can sell to all but the largest customers on a short-term basis. The basic structure of the open-access option is illustrated in Box 3.3, and some of its additional features are noted in Box 3.4.

Box 3.3 The Open-Access Pipeline Option



Box 3.4 Additional Features of the Open-Access Pipeline Option

Producers

- Producers sell directly to distributors and all other customers (but not to transmission companies), primarily on long-term take-or-pay contracts.

Upstream Regulation

- Licensing of acreage offshore is done by the host government, and onshore with the mineral rights owner. No price regulation is exerted at the wellhead, and the gas price is freely negotiated between the producers and the buyers (i.e., distribution companies and major customers).

Transmission

- The transmission company has transport function only. That is, it carries gas for producers, large customers, distribution companies, and others (including marketers) on an open-access basis from the custody transfer point of the gas supply to the distribution areas in the Gauteng area, Cape Town, or Natal.
- The possibility of inviting project proposals would need to be investigated, and project developers should be required to propose a tariff regime.
- No formal monopoly exists for gas transmission.

Ownership

- Preferably no producer or customer is allowed a controlling share in a transmission company, and no producer should control the distribution function. If this cannot be achieved, more regulation is required to check abuses of monopoly.

Regulation

- The regulatory agency monitors open access to the pipeline.
- A transportation tariff is recommended based on either price-cap or rate-of-return regulation with built-in incentives for cost-saving measures. In a new network, however, immediate productivity gains could not be expected, and if the price cap is introduced, the efficiency factor should be set at zero for at least the first period.
- Transmission tariffs are published.
- Planning and expansion of pipelines are not regulated, (except by general technical and environmental regulations). To put competitive pressure on the franchise holder to expand capacity, transmission franchises would not be exclusive; a company could build another transmission pipeline if it demonstrated that the public would be better served.
- Technical and operational standards are set.

Economic Rent

- The transmission company cannot extract excess economic rent if competing fuel prices rise, because the transport tariff is regulated.

(box continues on the next page)

(Box 3.4 continued)

Distribution

- The distributor buys gas from producers on long-term contracts.
- Franchises should be put to tender.
- New distribution companies are set up in particular franchise areas. They may have to be based on existing distribution companies. Distribution is exclusive in its area; that is, the distribution company has an exclusive franchise to build pipelines in the area but not a monopoly to sell gas to large customers (above a large threshold). Others can supply these customers through open access on the distribution network. Distribution companies have an obligation to serve customers in their franchise area who take less than the threshold and are located at a certain distance from the distribution network.
- Bypass (by using open access) of distribution companies is allowed for customers taking more than the threshold. In special cases the regulatory agency could allow a "physical bypass" if the producers or consumers could demonstrate that a direct pipeline from the transmission pipeline to the consumer would imply lower costs for the shipper. This would put competitive pressure on the franchise holder to ensure competitive distribution tariffs.

Regulation

- Transmission tariffs are regulated and costs of gas distribution are price-capped, eventually subject to an efficiency factor. Gas purchase costs are passed through to the customers.
- End-user prices for large customers are not regulated, except for the transmission costs (i.e., major industries and power plants negotiate prices with producers and transmission costs are added). Interfuel competition would provide a ceiling on the gas prices over the long term.
- Technical/operational regulation is applied.

Pros and Cons of Open-Access Pipeline

3.19 The positive aspects of the open-access pipeline may be summarized as follows:

- Generally, open-access provides a potential for future gas-to-gas competition because access to markets is assured. Direct sales from producers to customers could lead to lower prices in the future, and direct sales could result in expanded gas production and consumption.
- Producers usually prefer to deal with a few gas purchasers who can stand behind major long-term contracts. Distributors or marketers have a role in increasing competition by trading between producers and small- and medium-sized end users.
- Open access is a relatively new tool in avoiding abuse of monopolies and reducing costs of transportation.

3.20 On the other hand, several problems inhere in the open-access approach:

- Commercial banks indicate that open access would make the financing of pipelines difficult. Commercial banks tend to prefer to evaluate only a few balance sheets when trying to mitigate their risks. The introduction of open access on a pipeline implies that many players will be involved. On the other hand, open access would reduce dependency on one borrower's balance sheet and would diversify risks. One could argue that in a situation with open access, throughput agreements could ensure the revenues as well as take-or-pay agreements, and with many movers of gas, risks are more diversified than in the traditional gas chain.
- Because producers need long-term contracts to justify investments, this structure requires distributors to aggregate demand. This would result in relatively few companies buying gas (i.e., distribution companies and large consumers taking more than the threshold).
- No historical evidence is available to show that open access to pipelines has been introduced in a developing market at the time of introduction of natural gas and startup of the industry.

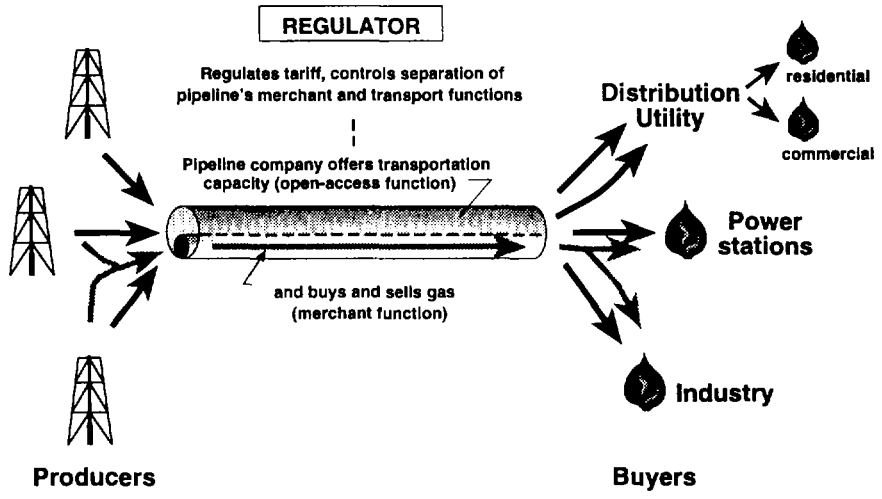
The Recommended Hybrid Option: An Open-Access Pipeline with Separate Subsidiaries Providing the Merchant Function

3.21 A hybrid of merchant and open-access options is the recommended strategy for South Africa. This hybrid option would attempt to combine the desirable features of the merchant and open-access options. In the hybrid approach, the transmission company would be allowed to buy and sell gas on its own account, but would *also* have to offer open access to its transportation capacity for third parties to use. In the hybrid approach, prices are negotiated between all players. The customers and the transmission company would compete to purchase from producers, and concomitantly the producers and the transmission company would compete to sell to the customers.

3.22 To ensure a level playing field, the transport functions and the merchant functions of the transmission company must be run as arms'-length activities in separate subsidiaries, and the transport subsidiary must apply the same terms, access rules, services, and tariffs to the merchant subsidiary as apply to third parties. Transportation tariffs and access rules hence must be regulated.

3.23 Although it is desirable to set up distribution companies, they are not essential in the way that they are for the open-access option, as the merchant part of the transmission company can supply the smaller industrial customers. This would leave distribution to concentrate on defined areas of dense customer offtake, such as major cities. The basic features of the recommended hybrid option are illustrated in Box 3.5, and some additional characteristics are listed in Box 3.6.

Box 3.5 The Recommended Hybrid Option



Box 3.6 Additional Features of the Hybrid Option

Producers

- The producers, whether domestic or foreign, sell to the transmission company and to large customers (e.g., power plants and producers of ammonia, fertilizers, and steel) on long-term take-or-pay contracts.

Upstream Regulation

- Licensing of acreage offshore is done by the host government, and onshore with the mineral rights owner. No price regulation is applied at the wellhead, and the price is freely negotiated between the producers and the buyers (i.e., transmission companies and major customers).

Transmission

- Separate transmission companies are set up, each with a franchise area from the custody transfer point of the gas supply to the distribution areas in Gauteng, Cape Town, and possibly Natal. Franchises are awarded based on project evaluation.
- The transmission company has two functions that operate at "arms' length":
  - *Merchant function.* The company buys gas on long-term contracts with producers. It sells to distribution companies and to industry outside the distribution companies' areas.
  - *Transport function.* Open access to spare capacity is given to producers and large customers for transport of gas to allow them to deal directly with each other.

(box continues on the next page)

(Box 3.6 continued)

Ownership

- Preferably no producer or customer is allowed a controlling share in a transmission company, and a producer should not be able to control the distribution function. If this cannot be achieved, more regulation will be required to check abuses of monopoly.

Regulation

- Open access is given to spare capacity in the pipeline system.
- The transport and merchant businesses should be in separate legal entities.
- The franchise should be subject to evaluation, and transportation tariffs recommended based on either price-cap or rate-of-return regulation with built-in incentives for cost-saving. In a new network, however, immediate productivity gains could not be expected, and if the price cap is introduced, the efficiency factor should be set at zero for at least the first period.
- Technical and operational standards are set.
- Planning and expansion of pipelines are not regulated (except via general technical and environmental rules). To put competitive pressure on the franchise holder to expand capacity, transmission franchises would not be exclusive; a company could build another transmission pipeline if it demonstrated that the public would be better served.
- The type of price regulation depends on whether it is transport business or merchant business. The transportation service would be regulated by either a price cap or rate-of-return regulation with built-in incentives for cost saving measures, whereas no regulation applies to the merchant function. Investments in excess capacity (for open access) are ensured by providing the right incentives via the transportation tariff (i.e., a reasonable rate of return). For investments in excess capacity, the transmission company would be likely to sign contracts for throughput volumes with producers and large customers.

Economic Rent

- The open-access element reduces the ability of the merchant company to take monopoly rent to the benefit of producers and customers. If competing fuel prices rise, the economic rent would tend to go upstream if there is only one producer.

Distribution

- New distribution companies are preferably set up in particular franchise areas. They may be based on existing distribution companies but ideally are put to international tender. If response from investors is insufficient, the transmission company should be allowed to distribute gas in a separate legal entity. Existing distribution companies may need protection (e.g., by giving them rights to participate in their existing franchise areas). Distribution is exclusive in its area; that is, the distributor has exclusive franchise to build pipelines in the area but not a monopoly to sell gas to large customers (above a large threshold). Others can supply these customers through open access on the distribution network. Distribution companies are obliged to serve customers in their area who take less than the threshold and are located at a certain distance from the network.

(box continues on the next page)

(Box 3.6 continued)

- Bypass (by using open access) of distribution companies is allowed for customers taking more than the threshold. In special cases the regulatory agency could allow a "physical bypass" if the producers or consumers could demonstrate that a direct pipeline from the transmission pipeline to the consumer would imply lower costs for the shipper. This would put competitive pressure on the franchise holder to ensure competitive distribution tariffs.

Regulation

- Transmission tariffs are regulated, and costs of gas distribution are price-capped, eventually subject to an efficiency factor. Gas purchase costs are passed through to the customers.
- End-user prices for large customers are not regulated, except for the transmission costs (i.e., major industries and power plants negotiate prices with producers, and transmission costs are added). Interfuel competition would provide a ceiling on the gas prices over the long term.
- Technical/operational regulation is applied.

Pros and Cons of the Hybrid Option

3.24 The hybrid option has a number of attractions:

- Initially, the projects under consideration in southern Africa are likely to build up around production from a single field and consumption by a few major customers. The hybrid option allows some potential for upstream involvement in the market when more gas comes on stream.
- The option has the capability to attract private investors. The financing of the merchant part of the pipeline will only involve evaluating a few balance sheets, and restricting open access to excess capacity should facilitate financing of pipelines because fewer players will be involved than in the open-access option.
- There are two possibilities regarding the size of the merchant versus the open-access business. This flexibility is an attraction of the option:
  - If the majority of the business is provided by the pipeline's merchant subsidiaries, the buildup of the capacity for new gas market would be easier to plan because it would be under the responsibility of a single company. Initially, this may be case.
  - If major customers buy gas directly from the producers—and sufficient excess capacity for open access is installed—only a small market would remain for gas sold by the pipeline itself.

3.25 Nonetheless, several problems would be raised by the hybrid approach:

- Open access will only be provided if the regulated tariff is high enough to provide adequate incentives. The regulatory agency will face a difficult task in deciding on the right level of tariffs that would give incentives for both investors and shippers.
- The largest customers taking the vast majority of the gas would be decisive in the planning of the pipeline and in influencing the initial size of the merchant and the open-access business.
- Attempts to put out (new) distribution franchises may prove difficult because of the smallness of the market.
- The transmission company might have to operate distribution outside Gauteng, Natal, and Cape Town.

Involvement by State-Owned Enterprises

3.26 During the 1970s and early 1980s, many countries formed state-owned oil and gas companies. Today, many of these state-owned companies have been wholly or partially privatized, and many more countries are reported as selling publicly owned oil companies than as forming new ones. The principal reasons countries have reduced their involvement in the petroleum sector and privatized their state-owned companies are as follows:

- Governments need funds for sectors where private funding is difficult to attract.
- Concerns have decreased about future oil price increases and oil security.
- Many countries have substantially reduced their central planning activities to increase efficiency.
- Many countries have come to feel that the public sector does not always make good entrepreneurial decisions because political factors get in the way.

Pros and Cons of ESKOM's Involvement

3.27 ESKOM could be considered as a potential transmitter and distributor of gas. The pros of its involvement in transmission and distribution are, briefly, as follows:

- Cost saving (e.g., in metering, billing) is likely.
- Its involvement would make financing easy.
- ESKOM brings utility experience.
- It would be a valuable partner as a minority shareholder.

3.28 The cons may be summarized as follows:

- If ESKOM became a majority shareholder this would severely limit competition by concentrating monopoly interest in transmission of both gas and electricity.

- ESKOM could exert a powerful monopoly influence in pricing negotiations with consumers.
- It is a state-owned company and could be subject to the possibilities of political interference.
- ESKOM could also be one of the largest customers.
- In some areas, a monopoly would exist in distribution of gas and electricity.
- Some conflicts of interest exist between electricity and gas.
- Increased regulation would be required because of the lack of competition.

Pros and Cons of Petronet's Involvement

3.29 As mentioned earlier, Petronet/Transnet are interested in participating in the gas transmission system or in joint ventures. The pros of Petronet's involvement are as follows:

- Petronet brings valuable pipelines to be used for gas transmission.
- The company's experience in operating oil pipelines could be useful.
- The company has access to financial resources.

3.30 The cons are as follows:

- It is a state-owned company and so is subject to constraints and may be open to political interference.
- Petronet's involvement in gas business may create a conflict of interest with other objectives of Transnet.
- Petronet's involvement in gas transport compounds the existing de facto monopoly in oil pipeline transport.

The cons would disappear if the spare oil pipeline capacity was privatized, however.

International Competition

3.31 The government should consider announcing that it is prepared to evaluate proposals from potential investors for transmission and distribution franchise areas to obtain international experience and to inject new ideas and capital into the project at lowest possible costs. The public might also be given an opportunity to participate. The transmission system would start at the custody transfer point of the gas supply and end at the distribution areas.

3.32 Before any announcement, the criteria for the project evaluation should be set out, and the intended regulatory framework for transmission pipelines and distribution (including end-user pricing for natural gas and alternative fuels) would have to be made clear. Also, it should be made clear how existing gas distribution (Gaskor, JWGD, Cape

Gas, and Port Elizabeth Gas) would interface with natural gas distribution. All four gas distributors face a decision about whether to compete or join in the introduction of natural gas. This is not an easy matter to resolve and is not addressed in detail here. Some points of consideration to be taken into account by the government are as follows:

- How should private and municipal entities be incorporated into the project evaluation for franchises?
- Should the franchise area include the area of these entities?

3.33 A clear framework for the project evaluation would make this and subsequent negotiations easier. It could include the following:

- No producer feeding the system or customer of the system should have a controlling share in the transmission system. A degree of South African ownership is desirable, as is an experienced overseas shareholder. Corresponding rules should apply to a distribution system, although this may require a modification to handle existing distribution. Only qualified and financially sound companies would be eligible; this could be ensured through prequalification.
- Each consortium should propose how it intends to consolidate and extend the system to meet the anticipated market and how much it proposes to invest. It should also propose a financing plan.
- Each consortium should be asked to define distribution areas with associated citygates and, if relevant, put distribution into separate subsidiaries. Each consortium should be encouraged to involve local interests and authorities as shareholders in the subsidiaries. Special provisions would apply to existing gas distributors in Johannesburg and Cape Town.
- The regulatory regime is essential to the project proposals and would be given to each consortium in full detail.
- Consortia are not paying for a franchise. Successful consortia obtain a 35-year franchise and the right to construct and operate pipelines for a transmission or a distribution area. Transmission franchises would not be exclusive, in that another transmission pipeline could be built if the company could demonstrate to the government that the public would be better served by construction of a second system. Distribution is exclusive in its area, however. This means that the distribution company has an exclusive franchise to build pipelines in the area but not a monopoly to sell gas to large customers (above a threshold consumption). Others can supply these customers through open access on the distribution network. In special cases the regulatory agency could allow a "physical bypass" if the producers or consumers could demonstrate that a direct pipeline from the transmission pipeline to the consumer would imply lower costs for the

shipper. This would put competitive pressure on the franchise holder to ensure competitive distribution tariffs.

3.34 In reality, much work remains to be done before project evaluation can be contemplated. The future role and level of participation of all the existing players must be resolved, and that is likely to require significant negotiation. With this information, however, it should be possible to define the industry structure and regulation in detail and to specify the process fully. Legislation will be needed and must be prepared, and parliamentary time must be found to consider it. All potential investors will need time to conduct their own market surveys and to estimate costs before taking part.

Upstream/Cross-Border Arrangements

3.35 As suggested in the earlier discussion (see chapter 1), much of the gas to supply South Africa will be imported, and arrangements to make trade feasible will be needed. The government of South Africa should therefore initiate discussions with the governments of both Mozambique and Namibia with the goal of harmonizing policies and procedures between the exporting and importing countries where needed and thus furthering the national and energy interests of the countries involved. The principles to be discussed and covered in any agreement should include some, if not all, of the following:

a. *Pipeline routing.* The route needs to satisfy importer and exporter from both environmental and usage standpoints.

b. *Construction timetable.* The governments need to agree to issue all necessary permits, licenses, certificates, rights-of-way, and so on for the expeditious commencement of construction and operation of the pipeline.

c. *Capacity:* The capacity installed and its utilization should be acceptable to both governments. Open access, if introduced, should apply in both countries.

d. *Financing.* The owners need to satisfy both governments that long-term financing is ensured and protections against risks of noncompletion, cost over-runs, and interruption and other risks are adequately addressed.

e. *Taxation.* Both governments need to assure each other against nondiscriminatory taxation, including establishing limits on property taxes.

f. *Tariffs.* The design of the tariffs and the procedures to calculate them should be acceptable to both governments.

g. *Supply of goods and services.* Both governments need to ensure that the goods and services for the project are obtained on competitive terms, taking into account price, reliability, quality, and delivery times.

h. *Technical standards.* Both governments need to agree on the technical standards—including safety standards—that will apply to the new pipeline.

Technical Regulation

3.36 The description of the existing gas business in South Africa in chapter 1 showed that different technical standards are employed by the different companies involved. A privately owned and even more diversified gas business will require the introduction of national standards for the construction and operation of pipelines and for metering. Where existing standards are deemed acceptable, even if they do not conform to the new national standard, they should be permitted for indefinite use, but any new or replacement work should conform to the new standard. Where existing standards are not satisfactory, a transition period should be allowed over which old equipment would be brought up to the new standards. The transition should be long enough to avoid causing severe financial hardship to any organization affected. Unsafe equipment, however, would have to be replaced without benefit of such a transition allowance. Legislation will be needed to set up the new standards, with requirements for approval of significant new installations, and the government will need rights to conduct inspections to ensure compliance. Many precedents are available for pipeline legislation around the world, and best practice can be derived from them. Health, safety, and environment should be handled by the agencies specializing in these areas.

Economic Regulation of the Downstream Gas Industry

3.37 Companies wishing to get involved in the downstream natural gas industry in South Africa will need to know the regulatory environment in which they will operate. It is essential, therefore, that the government gives considerable thought to this issue if it wishes to attract private investment capital to the sector. No country should change the "rules" after companies have invested in good faith.

3.38 Most countries with natural gas industries have introduced national legislation—so-called Gas Acts. This approach would be useful in South Africa. A Gas Act should be applied nationally to new entrants as well as to the existing industry. The Gas Act or Gas Law establishes the policy objectives for development, competition, and performance of the downstream gas sector, sets criteria for granting franchises, licenses, or authorizations, and defines the pricing methodology and the rights and obligations of the suppliers, transmission and distribution companies in the sector. Several of these acts include provisions to establish gas regulatory agencies; either a single regulator or a board/commission. The Gas Act is the framework for the day-to-day operational work of the regulatory agency. If it is decided to introduce a regulatory agency, the agency needs to instill confidence in consumers and investors that they will be fairly treated. The agency can accomplish this by establishing a record of objectivity in its assessments, transparency in its decisionmaking, and independence of political interference. Developing such a reputation will require the agency to attract quality personnel, publish well-reasoned decisions, and follow appropriate operating procedures.

3.39 One of the more important duties of regulatory agencies in the gas industry is the issuance of licenses to franchisees to provide the right to construct and operate pipelines to provide the public service of natural gas transportation. In all the options discussed above (see Boxes 3.1 to 3.6), transmission franchises would not be exclusive. Licenses also often obligate the franchisee to make certain required capital expenditures and to comply with certain other obligations relating to matters such as the quality of gas transported, invoicing, safety standards, and other conditions of service.

3.40 The government should seriously consider adopting most of the main duties, powers, and activities of regulatory agencies, as listed below:

- Enforcing the Gas Act and its implementing regulations.
- Enacting regulations governing technical standards and matters relating to billings, interruption, and reconnection of gas supply.
- Monitoring and collecting data on the companies' performances including financial performance.
- Ensuring that franchisees maintain their systems in good condition.
- Issuing permits authorizing construction and operation of pipelines.
- Preventing anticompetitive and discriminatory behavior.
- Preventing abuse of monopoly.
- If open access is introduced (in the open-access pipeline option or the hybrid option), the regulatory requirements would be expanded further to regulate the tariffs and other conditions of service for the franchises of open-access operations. Moreover, the regulatory agency should ensure that anticompetitive and discriminatory behavior is avoided in providing access to the pipeline, and between the merchant and the transport function of the pipeline company in the hybrid option.
- Setting the terms and conditions for competitive award of franchises and assisting the government in granting or extending franchises.
- Authorizing applications for rights of way, determining the compensation payable, and settling cases of dispute.
- Obtaining information from transporters and distributors and conducting inspections of their facilities.
- Determining and applying penalties, subject to due process, as provided in the legislation.
- If the agency is self-financing, setting the annual inspection and control fee in the context of the agency's annual budget submission to the government.

3.41 Private investors need to know how the regulations will be implemented before they make capital expenditures. This argues for enacting gas industry legislation

as soon as it is clear that a larger gas industry is likely to evolve and for hiring key regulatory staff to respond to the concerns of potential investors. It is vital that the role and responsibility of the agency is understood by both gas consumers and potential operators from the outset, since differences of opinion after the major capital investments are made would be highly disruptive.

3.42 The Gas Act should be drafted so that different sections could become effective as the need arose. Similarly, the staff required to operate an agency at the outset can be kept quite small and increased in tandem with the growth of the industry. Until a separate regulatory agency is established, the personnel appointed could perform their work under the auspices of an existing government department. The regulatory group can also use technical consultants to meet needs that are intermittent during the buildup period. When a separate regulatory agency is needed, a detailed description of its tasks and a limit on the its budget should be issued to help reassure the industry that the agency would not grow into a major bureaucracy.

3.43 The regulatory agency could be a single regulator or a commission/board, preferably an uneven number (three or five) so that decisions by voting are not tied. A commission/board would be less personalized and, if members served staggered terms, the board's decisions would tend to be more consistent over time. The potential for direct political influence on the regulatory agency would also be reduced if a commission/ board is chosen over an individual regulator. The decisions would be subject to more diverse viewpoints; this, however, would extend the decision process.

Combined Gas and Electricity Regulatory Agencies

3.44 It is critical for regulatory agencies be seen as independent of the political process. In some countries, such agencies have a separate revenue source so that they are not dependent on regular government revenues and hence political pressures. Independence of government funding and personnel rules also may be useful because regular government salaries may be inadequate to attract qualified personnel in this highly specialized field. To provide for funding for the regulatory agency, many countries collect fees (based on objective criteria, such as volume of gas transmitted, size, etc.) from companies in the regulated industries.

3.45 In some countries, the gas and power regulatory agencies are combined as a way of reducing costs and because of interaction between the two energy forms. This strategy has both pros and cons. The major advantages are threefold. First, where both industries are regulated and in competition, it is easier to maintain consistency of policy and timing if the two agencies are combined and the agency would less likely be captured by a particular industry. Second, some savings can be achieved in administration and manpower costs, as many of the investigations of the utilities require similar skills, particular in relation to accounting and financial analyses. The specialized staff would also benefit from day-to-day contact with other sectors. Third, in South Africa, an

electricity regulatory board was introduced in January 1995; joining gas regulation to the existing agency may be a good strategy because it could prove difficult to attract enough qualified people to staff two separate boards.

3.46 On the other hand, the gas and electricity industries are different in many important ways, and regulating both with a single agency could prove problematic on several grounds. First, the gas business is a complicated one in its own right, and the agency must have or acquire specific gas expertise. Second, the electricity industry in South Africa is much larger than the present gas industry, and this disparity will persist even after successful implementation of all the natural gas projects now being discussed. Thus, there is a significant risk that gas would become the "Cinderella" sibling in the regulatory family—that it would not receive adequate attention. Third, ESKOM and other main players in the electricity industry are public sector companies with a major role to play in the restructuring and development program. This is not the case in the present gas industry, and the future natural gas industry is likely to involve private sector companies supplying gas to specific markets. Thus, the split in ownership would make regulation of the two sectors different and difficult. Because of the disparate structure, ownership, objectives, and size of the gas and electricity industries, it is likely that regulating them through a single, joint agency would lead to a confusion of objectives.

Training

3.47 The government should initiate training for its staff on the regulatory issues discussed above to prepare for the introduction of natural gas. A gas section under DMEA should be established, and "twinning arrangements" should be considered to obtain regulatory experience from other countries. International experience and knowledge would be brought in on the industry side by international gas companies proposing investment projects, tariffs, and financing. However, both the government and the industry should work to develop training and other programs to bring disadvantaged South Africans into the process. At present, the forum is unbalanced in the sense that it is dominated by senior industrial executives who are mostly involved in their corporation's development. That is all well and good, but as has been shown by the national debates on energy development and electrification, wider participation is vital for full political acceptance of the evolving gas policies and regulations.

Conclusions and Recommendations

Industry Structure

3.48 The recommended structure for South Africa's developing natural gas industry is a hybrid of the merchant and open-access options because this hybrid arrangement has the best potential for attracting investors and stimulating competition. In the hybrid structure, the transmission company could buy and sell gas on its own account, but it would also have to offer open access to its transportation capacity to third parties. Distribution companies are desirable in this structure, but they are not essential, as the

merchant part of the transmission company could supply smaller industrial customers. Because the pipeline company would sell its own gas and transport gas for others, the large customers and distribution companies would have more options for gas supply. As a result, competition in the market would be increased compared with the other options. In areas where the market is small, such as Cape Town, other options might be preferable.

The Role of the Government

3.49 Private industry appears willing to develop gas to supply South Africa and to distribute and market gas within the country. Therefore, the state should not have to use its limited capital resources to develop the gas business. But the government should gear up for the important roles it will play in helping to introduce natural gas to the South African economy. Its principal tasks, in rough order of importance, are as follows: to set up and monitor the regulatory framework; to negotiate cross-border arrangements for importing gas from Mozambique and Namibia; and to evaluate the proposals that are likely to come from investors.

3.50 **The Regulatory Framework.** Companies wishing to become involved in the downstream natural gas industry in South Africa will need to know the regulatory environment in which they will operate. It is essential, therefore, if the government wishes to attract private investment capital to the sector, that it give considerable thought to this issue and develop solid and workable regulatory provisions and institutions. The "rules" should not be changed after companies have invested in good faith. Most countries with natural gas industries have introduced a regulatory framework in the form of a "Gas Act." This approach would be useful in South Africa. South Africa's Gas Act should be applied nationally—to new entrants as well as to the existing gas industry.

3.51 Regulation is recommended for gas transmission tariffs and for distribution costs for gas supply to small, captive consumers. The regulation should ensure that investors would have an incentive to keep costs down and earn extra profits. A price cap that would limit the increase in distribution costs to small, captive customers would provide for such an incentive and the regulation of pipeline tariffs should be based on either a price cap or a rate-of-return regulation with incentives for the transmission company to reduce costs. Gas purchase costs, however should be passed through to the customer. The government or a regulatory agency would be responsible for the regulation. For large customers, end-user prices are not regulated (except for the transmission cost). These customers would turn to other fuels if gas prices stayed at a higher level.

3.52 A downstream regulatory function would be required under all three options for industry structure (Boxes 3.1 to 3.6), but initially it would not need to be a large organization. The main duties would be as follows:

- Implement a Gas Act and its regulations.
- Issue permits authorizing construction and operation of pipelines.

- Regulate the costs of supply to captive customers.
- Prevent anti-competitive and discriminatory behavior and abuse of monopoly.
- To set the terms and conditions for competitive award of franchises.
- Enact regulations governing safety, technical, and environmental standards, billing for normal service and for connection, interruption, and reconnection of service.
- Ensure that the franchisees maintain their systems in good order.

3.53 If open access is introduced (in the open-access pipeline option or the recommended, hybrid, option), the regulatory requirements would be expanded further to regulate the tariffs and other conditions of service for the franchises of open-access operations. Moreover, the regulatory agency should ensure that anticompetitive and discriminatory behavior is avoided in providing access to the pipeline, and between the merchant and the transport function of the pipeline company in the recommended option.

3.54 **Cross-Border Arrangements.** Cross-border arrangements must be completed with Mozambique and Namibia in the following areas, where policies and procedures need to be harmonized:

- Pipeline routing
- Construction timetable
- Capacity
- Financing
- Taxation
- Tariffs
- Competitive terms for goods and services
- Technical standards.

3.55 **Evaluating Proposals.** Proposal evaluation would be necessary if the government actively called for proposals from investing consortia, or if the government decided to negotiate directly with interested parties. It is recommended that South Africa announce that it is prepared to evaluate proposals for transmission and distribution franchises. This is common in the gas industry and has the advantage of bringing in international experience, new ideas, and new capital at the lowest possible cost. Experience shows that when there is some degree of open, international competition, investors often propose pipeline systems and tariff structures that would otherwise not have been considered. The franchise for pipelines should enable the holder to construct the pipeline. For transmission pipelines, the franchise should not be exclusive, while distribution companies should have an exclusive right to build pipelines in the franchise area, except for special cases. However, they should not have a monopoly to sell gas in the franchise area.

3.56 **Long-Term Issues.** In addition to the issues preceding the introduction of natural gas in South Africa, the government needs to attend to a number of issues linked to natural gas' long-term development and competitiveness (these issues are not addressed in detail in this report, however, as they fall outside its scope):

- The integration of the existing gas distributors—Gaskor, JWGD, Cape Gas, and Port Elizabeth gas—with the new natural gas systems.
- Improvement of the terms under which rights to coal-bed methane are granted, especially distinguishing the rights to coal from the rights to gas.
- Whether pipeline owners can be allowed to write off depreciation of pipelines; this is presently not allowed, as pipelines are considered permanent infrastructure, which is not depreciable.
- The eventual restructuring of Soekor—and the optimal timing of the restructuring in relation to the recent licensing round—so that its upstream regulatory role is managed apart from its role as the state exploration and production company.
- Earmarking of subsidies and grants to Sasol for synthetic fuel production so that they are kept at arms' length from its other businesses, especially its Gaskor operations.
- Evaluating the several studies now in progress concerning the future of the Mossgas Project. If the outcome is that it would be possible to supply Cape Town with gas from Mossel Bay, the government would have a role in ensuring that a level playing field is maintained for the fiscal regime.
- Understanding the potential impact on gas development of the de-control of liquid fuels.
- Assessing LPG' s role in meeting the energy needs of the country.

Annex 1: List of People Met

	Name	*Affiliation*
1.	K. J. Randleff-Rasmussen, Manager Energy & Feedstocks	AECI Ltd.
2.	Y. Stelma, Energy Consultant	AECI Ltd.
3.	C. Falconer	Afrox, Handigas
4.	K. Bell, Consulting Geologist	Anglo American Corp. of South Africa Ltd.
5.	H. Roberts, Deputy General Manager Technical	CEF (Pty) Ltd.
6.	J. du Toit, Deputy General Manager Special Assignments	CEF (Pty) Ltd.
7.	W. M. Boyes	CEF
8.	K. Lloyd, Director	Capegas
9.	G. F. Keay, Director Directorate, Water & Waste	City of Johannesburg Water & Gas Dept.
10.	B. Bredenkamp, Deputy Director (Gas)	City of Johannesburg Water & Gas Directorate
11.	M. Pomeroy, City Electrical Engineer	Johannesburg Electricity
12.	J. Schyff	City of Johannesburg
13.	W. Meyer	Competition Board
14.	J. Moldto, Human Resources Manager	CSIR
15.	J. Botha, Deputy Director Electricity Supply	Dept. of Mineral & Energy Affairs
16.	J. Basson, Chief Director Energy	Dept. of Mineral & Energy Affairs
17.	Dr. J. Bredell	Dept. of Mineral & Energy Affairs
18.	T. Burger	Dept. of Mineral & Energy Affairs
19.	T. Surridge	Dept. of Mineral & Energy Affairs
20.	A. R. Dykes, Consultant	Dykes
21.	B. Bornstein	Easigas (Pty) Ltd.
22.	P. J. Cook, Executive Director Chief Executive, Finance	Engen Petroleum Ltd.
23.	W. Errol Martin, Chief Executive, Marketing	Engen Petroleum Ltd.

(continues on next page)

(List of People Met, continued)

	Name	*Affiliation*
24.	B. R. Paxton, Chief Executive, Planning & New Business	Engen Petroleum Ltd.
25.	A. Nel, General Manager Exploration & Production	Engen Petroleum Ltd.
26.	Dr. M. F. Winter	Engen Petroleum Ltd.
27.	S. H. Auret, Director	EPI Consulting
28.	J. R. van Deventer (Jaap) Corporate Strategy Manager	Eskom
29.	M. T. Davison, Consultant Corporate Strategy	Eskom
30.	R. G. Coney, Corporate Technology Strategy & Policy Manager	Eskom
31.	K. Robertson, Executive Director, Steel	ISCOR Ltd.
32.	A. M. Petrick, Divisional Manager Planning & Technology, Steel Division	ISCOR Ltd.
33.	Dr. T. Noska, Divisonal Manager Ironmaking	ISCOR Ltd.
34.	A. T. Holmes	ISCOR Ltd.
35.	M. Dawkins, General Manager Strategic Business Development	Karbochem
36.	E. L. Taylor, Director	Kynoch Fertilizer Ltd.
37.	H. Trollip	MEPC
38.	R. de Bruyn, Technical Manager	Mossgas
39.	W. I. L. van Niekerk, Manager Onshore Operations	Mossgas
40.	O. van Coppenhagen, Production Manager Onshore Project	Mossgas
41.	Dr. A. E. R. McIver, Group General Manager, Business Development	NCP
42.	C. Möller, Chief Executive	Petronet
43.	P. J. Oberholzer, Commercial Manager	Petronet (Pipeline Services)
44.	C. Smit	Petronet
45.	J. Morgan	Petronet
46.	D. Wellbeloved, Development Manager	Samancor Ltd.
47.	C. McClelland	Sapia
48.	D. J. J. de Villiers, Managing Director	Sasol Oil (Pty) Ltd.
49.	W. C. Rossouw	Sasol Oil (Pty) Ltd.
50.	I. Murray, Divisional Manager, Heating Fuels	Sasol Heating Fuels

(continues on next page)

(List of People Met, continued)

	Name	*Affiliation*
51.	W. Kritzinger, Manager, Marketing	Sasol Heating Fuels
52.	R. van Wyk (AP)	Sasol Chem. Indus.(Pty) Ltd..
53.	M. Vorster, Manager, Natural Gas Development	Sasol Ltd.
54.	P. P.A. Steyn, General Manager Mineral & Energy Resources	Sasol Ltd.
55.	M. McDonald, Head, Economics Division	SEIFSA
56.	Dr. J. L. Job, Managing Director	Sentrachem Ltd.
57.	A. M. Ras, General Manager Corporate Planning	Sentrachem Ltd.
58.	L. Roos, Project Manager	Sentrachem Ltd.
59.	W. Naicker, Marketing/Commercial Manager	Sentrachem Ltd.
60.	J. McGiddy	Shell, South Africa
61	L. Kegge	Shell, South Africa
62.	J. Holliday, Division Manager	Soekor
63.	W. A. de Meyer, Chief Economist	Soekor
64.	K. Stallbom, Manager Petroleum Engineering	Soekor
65.	M. J. Heuser	Soekor
66.	W. Schoeman	Soekor
67.	B. J. Pieters	Suprachem
68.	Professor D.J. Kotzé, Director Institute for Energy Studies	Rand Afrikaans University
69.	C. Cooper, Director, Energy Research	Rand Afrikaans University
70.	N. J. Maas, Consultant	Rand Afrikaans University
71.	Professor R.K. Dutkiewicz, Director	University of Cape Town Energy Research Institute
72.	B. H. A. Winter, Consultant	University of Cape Town Energy Research Institute
73.	A. Eberhard	University of Cape Town Energy Research Institute/ Energy for Development Research Center

Annex 2: Structural and Contractual Issues in the Gas Business

Preconditions for Development

A2.1 It is never easy to introduce gas into a market where it has not played a significant role. Gas developments have certain characteristics that make them particularly vulnerable.

A2.2 To begin with, gas developments are *capital intensive* and require a substantial scale to be economic. This is true whether the investments are made by the public or the private sector, although the public sector is often prepared to invest for lower returns than the private sector. If the private sector is not willing to invest, it may be justifiable for Government to invest in certain circumstances.

A2.3 Gas is also expensive and *inflexible to transport*. Gas is generally moved through fixed pipelines that are expensive to construct and impossible to move, once built. Accordingly, when a gas field is developed, it inevitably commits itself to one chosen market for the life of the project. If the chosen market fails or does not come up to expectations, the gas cannot be shifted to an alternative market without massive expenditures that likely would render the investment totally unprofitable. (The only gas market that is flexible enough to escape some of these constraints is the United States, where ample spare pipeline capacity exists.)

A2.4 In many gas projects, only one customer (often a state monopoly) takes most of the gas, or one or two *very large customers are the mainstays of the development*. A problem that develops with one of these customers that affects either the price of gas or the volume lifted can undermine the entire basis of the investment.

A2.5 It is important to note that *the gas developer makes virtually the whole of its investment before a cubic meter of gas flows* and before it receives any income. The developer will therefore be very cautious about making the investment unless it has real confidence that gas will continue to be taken by the market in sufficient volume and at a high enough price. The investment is very vulnerable to opportunistic behavior by the customer, who may be tempted to switch some or all supply if cheaper gas comes along later. Such cheaper gas can and does become available because subsequent developments can take advantage of the infrastructure and scale benefits provided by the initial development. The customer also can cut the price unilaterally to the developer, who once it has sunk its capital, has little option but to continue to produce and sell gas at the reduced price and make the best of a bad job.

A2.6 Gas developers have evolved a number of *strategies* to overcome these problems and to allow gas developments to take place.

A2.7 To achieve sufficient scale for the initial development it is important to achieve a large volume of sales quickly after startup. This is of fundamental importance to the project economics and can hardly be stressed enough. The ways in which it can be done are limited. Where there has been a significant town gas industry, before the introduction of natural gas, replacement of the town gas by (usually much cheaper) natural gas can form a significant element. This is not the case in South Africa, where the scale of the manufactured gas industry is small. The most important element normally is to gain a major industrial customer whose need coincides with the availability of the new gas supply or who can easily and economically convert to gas from an existing fuel (or feedstock in the case of certain major chemical uses). In most parts of the world the only viable candidate to provide this baseload offtake is electricity generation. What is usually involved is construction of new gas-fired combined-cycle generating plant on a time scale that matches the introduction of natural gas supply. Major minerals processing plants or ammonia or methanol plants also can fulfill this role, but because their scale is usually smaller, it may take several such base customers, rather than a single one. To avoid inflexibility of offtake, the new gas field will generally want to supplement whatever baseload customer it acquires with a mix of other smaller customers having a range of price and offtake profiles. Mossgas is clearly an example of a baseload customer supporting the development of a gas field, and its experience shows how easy it is to get into difficulties when the baseload plant is itself not economic. It also shows how reliance on a single customer gives rise to offtake flexibility problems. The high operational rate of Mossgas (above the originally foreseen design capacity) makes a significant contribution to shortening field life, as it is such a high proportion of the total lifting from the field.

A2.8 Distance from field to market is another major consideration for the gas developer. Obviously, the nearer the field is to its major markets the less the problem of transport cost. In the case of South Africa, however, distances are large. Even the closest potential new source of gas, coal-bed methane, is more than 300 km from its major markets, and Kudu and Pande gas are three and four times that distance, respectively. As well as loading the pipelines as quickly as possible, the developer will attempt to keep costs down by minimizing the daily and seasonal variations in throughput of gas, by encouraging customers who take a regular pattern and also by constructing storage near the market, offering interruptible contracts that allow supplies to be cut off at times of high demand on the system. However, the most important consideration in achieving reasonable returns, while keeping gas prices as low as possible, is to seek long-term take-or-pay contracts from customers. These contracts give the developer confidence in cash flow over a long period and reduce the risk of the investment. This allows the developer to accept a slower payout than would otherwise be the case, and this is more often than not the only way the developer can afford to offer prices the market can bear.

A2.9 Take-or-pay contracts of something like 20 years' duration with defined pricing provisions (albeit with reopeners) are also the key to dealing with a single customer (and indeed are often the reason why agreements are made with a single

customer). It is of prime concern to the developer that the customer can live up to the obligations of the long-term contract, which will usually represent a commitment over its life of several billion rand. It is not surprising that only large companies are capable of entering into such undertakings. In the case of power generation, long-term contracts are usually a prerequisite from both sides, as the ability to finance the power station development depends on a long-term assurance of gas supply, as much as the gas field requires an assured offtake. This usually constrains the power station to base load operation.

A2.10 The long-term take-or-pay contract also provides the main deterrent to opportunistic behavior by gas customers. A wise gas developer will, however, want to get to know and trust its customers before doing business with them. The developer is very vulnerable to repudiation after a contract has started. The major defense against this is a degree of vertical integration in the gas business. It is common for customers to be offered some stake in the field development to discourage opportunistic behavior and to align buyer and seller interests more closely in what is a very long-term partnership. It is equally common for the field owner to have interests in the main delivery pipelines and also sometimes in the distribution systems.

Structural Issues in the Gas Business

A2.11 A corollary of the high cost of transporting gas is that the transport and distribution systems have strong natural monopoly characteristics. It rarely makes economic sense for a newcomer to attempt to compete with an existing supplier by laying an alternative pipe network. This fact allows the monopoly distributor to do a number of things, some in the customer's advantage and some not. It does mean that (in the absence of controls) prices will be set by the alternative fuels available to customers (mainly petroleum products) and that a degree of price discrimination can exist between broadly similar customers. In many cases, direct gas-to-gas competition could lead to lower prices for the majority of customers. The monopsony buyer is in a good position, however, to buy gas as cheaply as possible from the supplier, who generally has no alternative customer. This can result in a national benefit that can appear either as taxation of the distributor's profits or as reduced gas prices. The gas supplier can offer customers short-term contracts with confidence, even though he buys on a long-term basis. It also allows the distributor to supply customers having a wide range of load factor (the ratio of average take to peak take) and to invest in storage and offer interruptible contracts to balance the difference in load factor between suppliers and customer offtake. It is not always appreciated that there is a very large additional cost involved in supplying a small domestic customer who takes most of his gas in cold weather, and mainly in the morning and evening periods, compared with a large steady industrial user. Clearly these services are provided where there is gas-to-gas competition, but greater difficulties are involved, so fewer customers are typically supplied.

A2.12 The monopsony purchaser also has the whole responsibility for balancing supply and demand. There is no link between the cost of gas and price in the market

place and therefore no market-clearing price for gas. In the absence of this, the gas purchaser has to substitute its own price signals to indicate to the gas suppliers when more gas is needed. This can work reasonably well, but it always leads to some distortions, and distributors will tend to ration demand in times of shortage rather than let prices rise freely to suppliers. On the other hand, if they are oversupplied they will absorb take-or-pay within reason. It has been claimed forcefully that the overall effect is to inhibit the natural growth of gas markets and to keep the full benefits of gas from flowing to the consumers (or to the developers when more gas is needed). It is hard to believe that supply planning can work as well or allocate resources as efficiently as a truly competitive market would.

A2.13 The result of the developers need to start development and the natural monopoly characteristics of transport and distribution is that the gas business in any country almost invariably begins with a very concentrated and monopolistic structure. Competition between resource owners to develop their fields to supply the market usually emerges fairly quickly as the market develops. Gas -to-gas competition does not develop naturally, as it is in the interest of the monopoly distributor to prevent third-party access to the distribution system.

Economics of Long-Term Contracts and Vertical Integration

A2.14 Long-term contracts and vertical integration have been regarded with some suspicion by free-market economists as market imperfections, which act as a contrived impediment to the continuous free adjustment of supply and demand, and as a potential barrier to entry. More recently, however, it has become accepted that in certain circumstances long-term contracts are the most efficient and natural method of free market transaction. The chief characteristics of a market leading to long-term contracting are as follows:

a. *Asset specificity.* Where large, long-lived investments, once they have been made, become locked into one particular use or customer (e.g., for reasons of geographical location or some physical characteristic of the asset).

b. *Small numbers.* Where a large number of potential customers may be available for the output of an investment, the disadvantages of asset specificity are considerably reduced, and spot markets may develop. However, where only a few (or even one) potential customer exists for the gas, this factor, combined with asset specificity, presents greater scope for opportunistic behavior by the customer (who can for example reduce the price unilaterally to marginal operating cost after the investment is committed without putting the supply at risk). Even if before commitment a large number of potential customers are potential consumers for the gas, often decisions taken at the commitment stage will close off most or all of these except for the chosen contractual partner. Thus, however, large the potential market, the small-number problem is still inevitable after the investment is made, and the big problem then is opportunism by the customer at that stage.

c. *Lumpiness of investment.* Where each investment is large and indivisible, so that it makes a significant impact on the overall market, these problems are exacerbated.

A2.15 If potential investors feel they cannot forestall opportunism of the consumer, they likely will not commit to the investment, even though it would be beneficial for both investor and purchaser. Thus, credible long-term contracts are indispensable for the efficiency of such markets. Credibility is of course as important as the contract itself. A contract that fails before its full duration simply throws the investor back into the problem. Vertical integration tends to arise in situations where long-term contracts may not be totally credible.[4]

A2.16 Gas developments, particularly in developing markets, exhibit a high degree of asset specificity and lumpiness. In most cases, the number of potential customers is small. Hence long-term contracts and vertical integration are features found extensively in the gas business and are necessary to the existence of the business in most areas. It is not expected that the gas business in South Africa can develop without some element of both.

Natural Monopoly and Gas-to-Gas Competition

A2.17 Although the reasons for the way in which gas businesses have developed are reasonably well understood, many countries still have concerns about these monopolistic structures. In many cases, state-owned monopolies and sometimes privately owned but totally unregulated monopolies have formed a central feature of the industry. It is felt that in a mature business these do not work wholly in the public interest and are not essential to the continuance of a healthy gas industry.

A2.18 Concern has provoked a number of countries to attempt to reform their gas businesses, although the process is not complete anywhere.

A2.19 Two major tools of reform are used in some degree by everyone that has attempted to do it. The first is the introduction of competition; the second is the regulation of monopolistic behavior.

A2.20 Competition is better than regulation in the view of many. Market mechanisms and the possibility of business failure are widely recognized as the best way of ensuring the most appropriate allocation of resources, and the quickest adaptation to changing market conditions. Competition has the added advantage that it is self-regulating and hence does not need outside intervention.

A2.21 In the case of a natural monopoly such as gas transportation, it is virtually impossible to introduce any real level of competition, and in any case duplication of pipeline systems is often an inefficient use of resources. Here there is no real alternative

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4. Most of these ideas are brought together by Williamson in *The Economic Institutions of Capitalism* (Free Press, 1985) and in Klein, Crawford, and Alchian, "Vertical Integration, Appropriable Rents, and the Competitive Contracting Process," *Journal of Law and Economics* 1978.

to external regulation to limit the abuse of the monopoly. The main problem with regulation is that it is not self-adjusting, and it is all too easy, via regulation, to introduce distortions into the market. In addition, the process is bureaucratic and may be costly to administer. These factors have stimulated a search for methods of regulation that try to mimic the effects of competition, to give the regulated bodies similar incentives to the market place, in an attempt to reduce regulatory distortions. In parallel with this has been a move to make regulation simpler and less costly. These two motives are not necessarily compatible.

A2.22 In most places that have attempted reform, the focus has been on promoting gas-to-gas competition. As several gas producers generally are supplying the transmission and distribution system, and invariably many customers are taking gas at this level, competition is primarily a matter of allowing the gas producers to compete to supply the customers. The main vehicle is to allow suppliers and customers "open access" (also known as third-party access; TPA) to the monopoly transport systems. This allows interested parties to move gas through the transmission and distribution system, at least to the extent that it has spare capacity, and therefore puts suppliers and customers into a position to deal with each other directly.

A2.23 Ironically, this competitive environment is achieved by regulation. The transmission company is required first to offer spare capacity to third parties and second to charge a regulated and nondiscriminatory tariff.

A2.24 Unfortunately, the process is not as simple as it sounds. In fact, the transmission and distribution companies perform several services in addition to simply transporting gas. They buy gas in bulk on long-term contracts and sell it in much smaller parcels, usually on short-term arrangements. In addition, the distributor performs a load management service. It usually buys gas from the suppliers at a fairly constant delivery rate, but allows customers to offtake gas in line with their needs. In many cases this results in very uneven offtakes. Where space heating is significant takes are much higher in cold weather. Industrial customers often do not take gas at night or weekends. The distributor has to match offtake and input quite closely as the pipeline system itself has very limited capacity to handle imbalances. This is done by taking gas into storage at times of low demand and releasing it at peak periods and by using interruptible customers who agree be cut off at peak periods in exchange for a discounted price. Gas can be stored in depleted gas fields, salt caverns, or low-pressure gasholders. These devices are expensive and have strictly limited capacity. The distributor can also assure a high degree of supplier reliability as it can use its multiple sources of supply to cover short-term interruptions (e.g., maintenance shutdowns on any individual field). Direct buyers and sellers will usually want access to some or all of these services. It is necessary that they can be priced and regulated separately and that access to them can be assured. This can be a very complex exercise on a large and well-developed system. The process of identifying and pricing services separately is generally known as "unbundling." The best-known example is the U.S. transmission companies, which used to buy and sell gas on their own account as well as transporting it. They have now been required to separate

these two functions—to the point where they have had to put their marketing activities in separate subsidiary companies from the transportation activities.

A2.25 It is also a far more complex matter for the transmission and distribution companies to ensure that system inputs and outputs are in balance and to measure what use has been made of storage services when many parties are using the pipeline system. This requires common system rules and standards, which are overseen by the regulatory agency.

A2.26 Clearly, the South African gas industry is not developed to the point where it is ripe for these reforms. However, even in the small industry that does exist, the distributors have unregulated local monopolies. Several customers have expressed concern about this.

A2.27 The South African government should attempt to set up an industry that has adequate security to attract the initial investment required but that can evolve toward a more competitive mode when it is robust enough to do so, without requiring radical reform to bring about the changes. This is an ideal goal, but it has not been attempted anywhere else yet, no doubt partly because the general movement toward reform of gas industries is itself comparatively recent.

Annex 3: Depreciation Study of Pipelines in Seven Countries

Prepared by CW Energy Tax Consultants, Ltd., March 1995

A3.1 Most countries levy some form of income tax on the business profits of corporations. Commonly, the tax is applied to book earnings (i.e., the profits shown by the audited account), but each country determines whether adjustments should be made to those earnings to determine the level of taxable profits.

A3.2 One such area is the treatment of capital expenditure. Most taxation systems accept the need to amortize the bulk of capital expenditures to arrive at a taxable profit. This recognizes the fact that if a company has invested, say, 100 in purchasing a piece of equipment, the company must recover that 100 before it has earned a true profit. However, most systems also recognize that except where the government wants to provide an investment incentive, it would be inappropriate to deduct the whole of the capital expenditure against one year's income, and thus provision is made for some way to spread the expense over a number of years.

A3.3 The following is a summary of the approach taken by a number of countries to the cost of investment in pipelines. The information is based on our own experience and additional information obtained from textbooks and other publications; in addition (for Canada, the United States, Australia, and the Netherlands), we have confirmed our understanding with experienced local tax advisers.

United Kingdom

A3.4 The United Kingdom (UK) is a good example of a country that distinguishes in its tax legislation between revenue expenditure and capital expenditure such that capital expenditure is only deductible if there is a specific provision permitting such a deduction. Expenditure on certain buildings, plant, and equipment qualifies for tax relief under a Capital Allowances code. The amortization or depreciation within the company's books is disallowed for tax purposes, and a separate amount of tax relief is given if the asset expenditure qualifies for relief within the Capital Allowances code.

A3.5 Pipelines fall within the definition of plant for UK tax purposes regardless of the type of pipeline; thus, pipelines that transport water, gas, petroleum products, or crude oil qualify for relief on the same basis. Provisions require that the claimant be the owner of the pipeline and, given that pipelines can cross land belonging to third parties or the Crown (the State), it is necessary to ensure that the claimant has a sufficient legal ownership to claim the relief, or that it satisfies other requirements under which tax relief may be given to persons holding less than a full legal interest. In practice, it is unlikely that a company incurring the expenditure could not satisfy the ownership or deemed ownership requirement.

A3.6 The rate of relief is 25 percent per annum on a declining-balance basis (i.e., 25 percent is allowed in year 1, and 25 percent of 75 percent in year 2, and so on).

A3.7 Pipelines owned by utilities are treated no differently from other pipelines.

Netherlands

A3.8 The tax system in the Netherlands is quite different from the UK system. Taxable income is based on book profit, and providing that the company has adopted an acceptable method of accounting, the amortization or depreciation in the accounts will be accepted for tax purposes.

A3.9 Pipelines used to transport crude or gas may be amortized on a "unit of production" basis, although in general the asset would usually be written off on a straight-line basis over the asset's anticipated useful life; thus, if a pipeline is expected to have an economic life of 10 years, the cost would be written off at one-tenth per annum. The determination of economic life is first made by the company and verified by the auditors as part of the audit process.

A3.10 A "unit of production" basis is only possible where the pipeline is used to transport hydrocarbons or other minerals from a particular producing source, and the write-off is then calculated by taking the ratio of that year's production transported through the line over the anticipated throughput for that year and all future periods; thus, if the production transported by the pipeline is 100, and the anticipated future throughput is 1900, one-twentieth of the capital cost will be deductible. Transmission lines would be amortized on a straight-line basis over the pipeline's economic life.

Canada

A3.11 The Canadian tax system is similar to that for the United Kingdom in that a Capital Cost Allowance (CCA) is available. Relief is available on a declining-balance basis with only one-half of the otherwise-allowable rate being allowed in the year of acquisition of the asset.

A3.12 All pipelines qualify for CCA, but the rate of allowance per annum varies depending on the type of pipeline. Oil or natural gas pipelines where the source of supply is expected to last no more than 15 years can qualify for an annual CCA of 20 percent on a declining-balance basis. Pipelines within an oil field or a refinery qualifies for a 30 percent annual allowance, as do pipelines for gaining or producing income from mining.

A3.13 Other pipelines which include transmission lines qualify for relief at 4 percent per annum, again on a declining-balance basis.

United States

A3.14 In the United States, the various types of pipelines are not treated differently in that the costs are either amortized over the useful life of the pipeline or, where appropriate, the lease for the land over which the pipeline passes or where the pipeline is dedicated to the source of the throughput over the life of that source. A unit-of-production basis, as described for the Netherlands, is an acceptable basis of depreciation in the United States.

Argentina

A3.15 Argentina's tax system provides for depreciation of capital assets on a straight-line basis by dividing the cost of the asset by the years of its estimated useful life.

A3.16 There is a presumption for buildings and other immovable property, which would include most pipelines, that the asset has a useful life of more than 50 years, and thus, for this category of assets, depreciation at 2 percent per annum over 50 years is deducted. However, if the company can provide sufficient proof that the useful life of the asset is likely to be less than 50 years, or it can show that a more appropriate basis for taking the depreciation should be applied (e.g., a throughput or unit-of-production basis), that depreciation will apply instead of the 2 percent.

A3.17 No special rules apply to pipelines; all types are treated the same manner.

Australia

A3.18 The Australian tax system is similar to the Canadian and UK tax systems in providing for specific rates of allowance for qualifying capital expenditures. Oil and gas pipelines qualify for amortization on a 10 percent per annum straight-line basis (i.e., one-tenth of the cost is written off each year), or, if the field life is shorter, the cost will be written off over that period.

A3.19 For other pipelines, the normal depreciation rates apply, and for a pipeline with a long useful life this is likely to be 13 percent per annum on a declining-balance basis. As in the United Kingdom, it is important in Australia for tax purposes that the company incurring the pipeline expenditure has an ownership interest in the land. But also, as in the UK, a lease or easement is sufficient to establish such an interest. However, most pipelines that have been built otherwise than for mines or oil and gas operations have been built by the States and are not in corporate ownership.

South Africa

A3.20 The South African tax system is similar to a number of others in that no deduction is given for the depreciation of capital assets as shown in the company's accounts, but specific amounts of relief are available for expenditure on qualifying assets. The rates vary depending on the asset and the business in which the asset is employed.

A3.21 Mining expenditure is deductible in the year of assessment during which the expense is incurred, but it may only be set-off against income from mining. Expenditure incurred prior to the commencement of production is capitalized and may be set-off against future mining income of a producing mine. The capital expenditure in respect of the mining operation, which is for tax purposes the process by which any mineral (including "natural" oil) is won from the soil or any substance or constituent thereof, includes the cost of shaft sinking and mine equipment. In the case of a "natural oil mine," the cost of laying pipelines from the mining block to the marine terminal or the local refinery is also included. However, any railway line or system (including pipelines) having a similar function for the transport of minerals from the mine to the nearest public transport system or outlet may be written-off on a straight-line basis over a period of 10 years. Although the word "equipment" is not defined, it in effect includes any kind of plant, machinery, and building on the mine that is used in the mining operations.

A3.22 However, depreciation allowances or Capital Allowances are not available for buildings or other structures or works of a permanent nature, unless there is a specific piece of legislation providing for that deduction. Other than in the case of mining operations, no such legislation exists to cover pipelines per se; thus if a transmission line is regarded as a structure of permanent nature, no relief would be available for the acquisition or construction cost. In order to claim tax relief successfully, the company would need to demonstrate that it owned the pipeline, that the pipeline qualified as plant and was not a structure of a permanent nature, and that the pipeline reduces in value each year by reason of wear and tear or depreciation.

Summary

A3.23 Among the countries I have reviewed, I have not found one that will not permit a deduction for tax purposes for the cost of a pipeline. The lowest rates of relief given are the 4 percent per annum provided by the Canadian tax system and the 2 percent by the Argentine system, but the latter country will permit a higher deduction if the pipeline has a useful life shorter than 50 years.

A3.24 For all countries where the useful life of an asset is an important matter, we believe that in determining the useful life of a pipeline, regard would be had to its economic life (i.e., the period over which it will be used to generate income) and its physical life (i.e., the period over which the pipeline can be used by being adequately maintained rather than replaced).

A3.25 The main difference between the South African tax system and those of the countries we have reviewed is that while a number of countries do not permit the deduction for the depreciation of certain capitol assets, in particular land and permanent structures, this does not operate to exclude the cost of pipelines. This reflects the income producing nature of a pipeline and the fact that pipelines corrode and do not have an indefinite physical life.

Joint UNDP/World Bank

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	103/89
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
Ethiopia	Energy Assessment (English)	07/84	4741-ET

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ethiopia	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87
	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Energy Assessment (English and French)	07/91	8017-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vol. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
Republic of South Africa	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86

Region/Country	*Activity/Report Title*	*Date*	*Number*
Uganda	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
Zambia	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Petroleum Management Assistance (English)	12/89	109/89
	Power Sector Management Institution Building (English)	09/89	--
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP)	12/94	--

EAST ASIA AND PACIFIC (EAP)

Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA

Region/Country	*Activity/Report Title*	*Date*	*Number*
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979/SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
Western Samoa	Energy Assessment (English)	06/85	5497-WSO
	SOUTH ASIA (SAS)		
Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89

Region/Country	*Activity/Report Title*	*Date*	*Number*
Pakistan	National Household Energy Survey and Strategy Fomulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
Sri Lanka	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
Sri Lanka	Industrial Energy Conservation Study (English)	03/86	054/86
	EUROPE AND CENTRAL ASIA (ECA)		
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
Portugal	Energy Assessment (English)	04/84	4824-PO
Turkey	Energy Assessment (English)	03/83	3877-TU
	MIDDLE EAST AND NORTH AFRICA (MNA)		
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector(English)	06/90	115/90
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91
	LATIN AMERICA AND THE CARIBBEAN (LAC)		
LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	National Energy Plan (Spanish)	08/91	131/91
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93

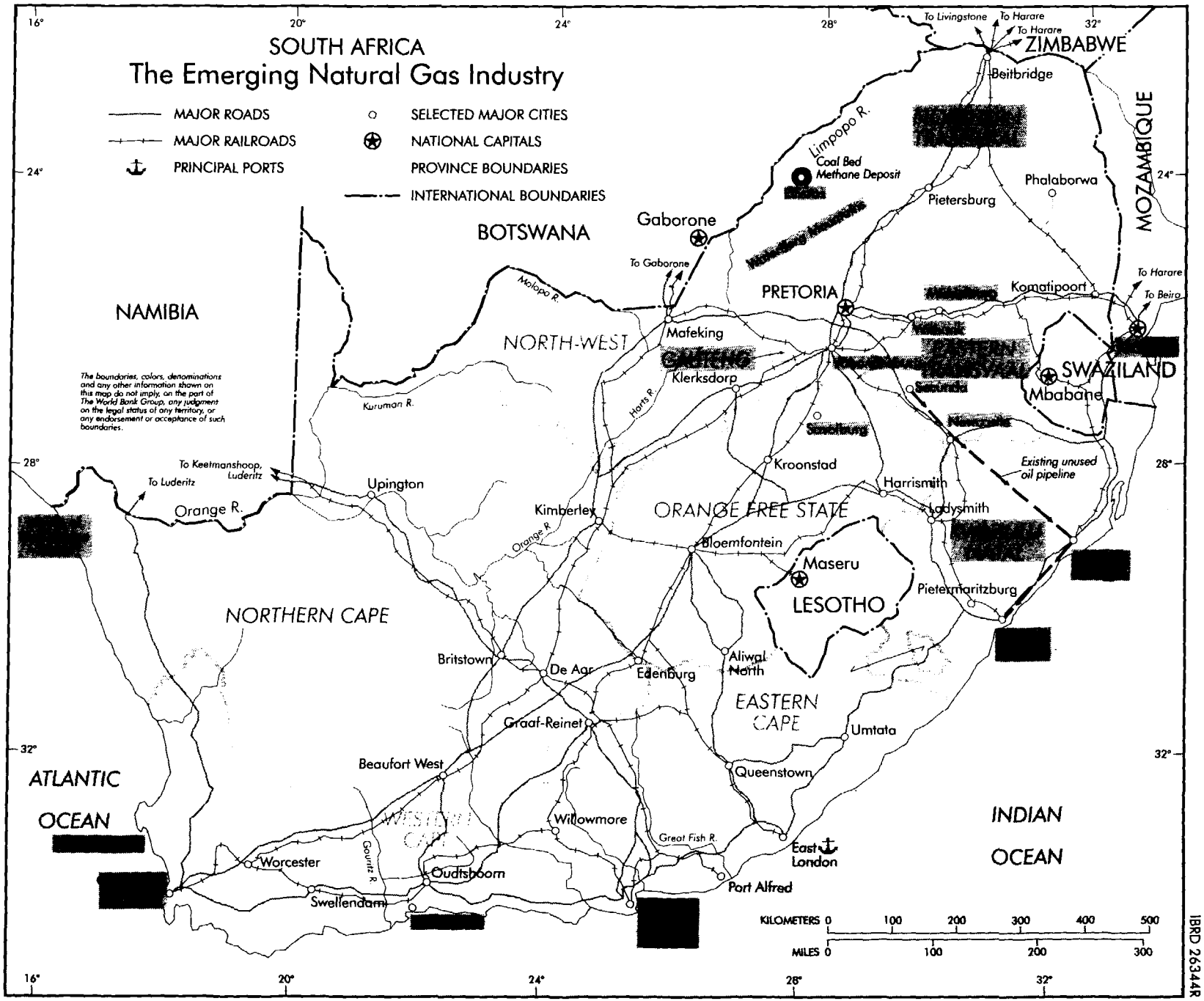
Region/Country	*Activity/Report Title*	*Date*	*Number*
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
Costa Rica	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
Ecuador	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
Haiti	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

Region/Country	*Activity/Report Title*	*Date*	*Number*

GLOBAL

Energy End Use Efficiency: Research and Strategy (English)	11/89	--
Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93
Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
Development of Regional Electric Power Networks (English)	10/94	
Roundtable on Energy Efficiency (English)	02/95	171/95

05/09/95



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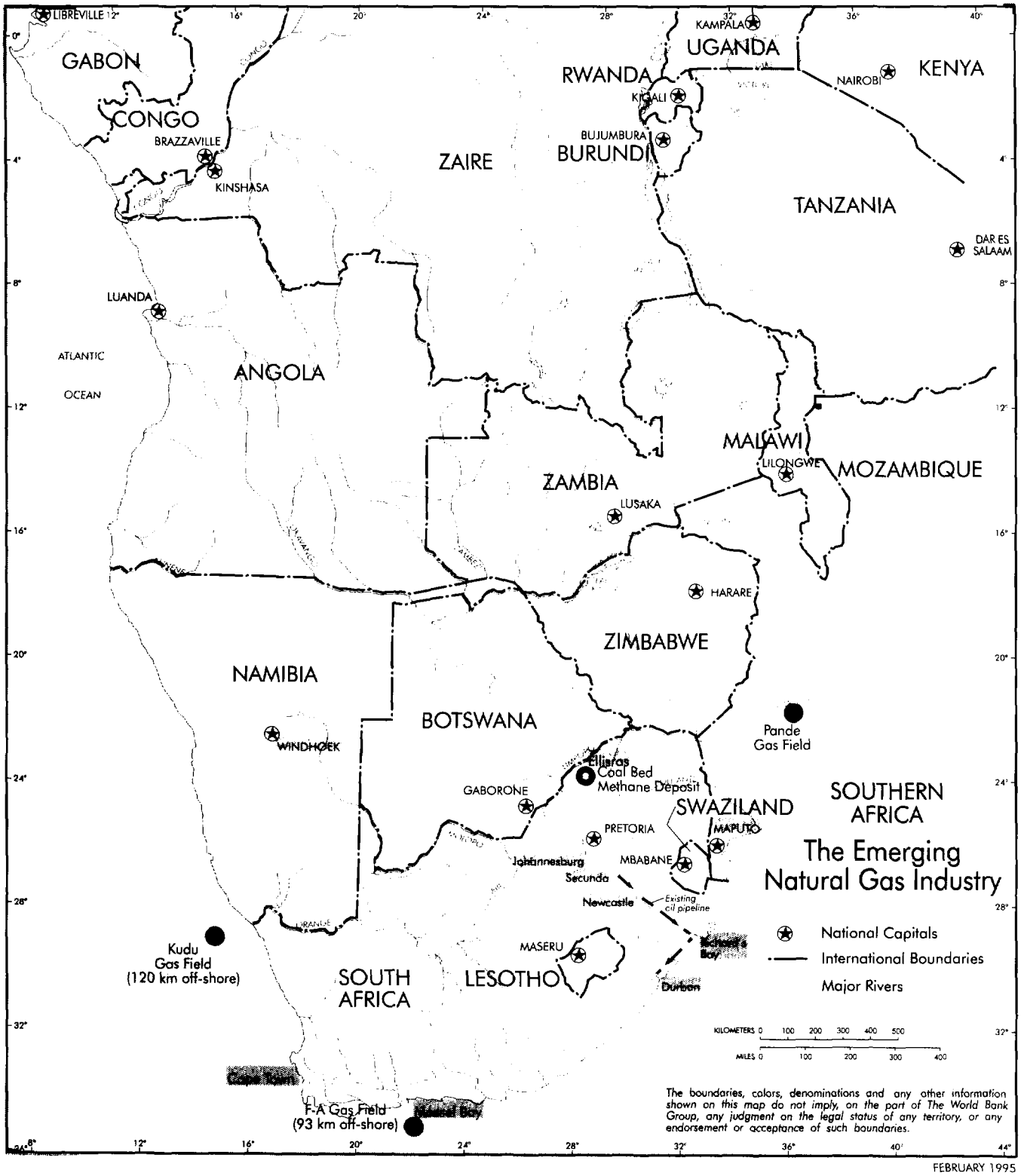

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