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Energy Sector Management Assistance Programme

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Bolivia

Natural Gas Sector Policies and Issues

Report No. 164/93

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

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) was launched in 1983 to complement the Energy Assessment Programme, established three years earlier. ESMAP's original purpose was to implement key recommendations of the Energy Assessment reports and ensure that proposed investments in the energy sector represented the most efficient use of scarce domestic and external resources. In 1990, an international Commission addressed ESMAP's role for the 1990s and, noting the vital role of adequate and affordable energy in economic growth, concluded that the Programme should intensify its efforts to assist developing countries to manage their energy sectors more effectively. The Commission also recommended that ESMAP concentrate on making long-term efforts in a smaller number of countries. The Commission's report was endorsed at ESMAP's November 1990 Annual Meeting and prompted an extensive reorganization and reorientation of the Programme. Today, ESMAP is conducting Energy Assessments, performing preinvestment and prefeasibility work, and providing institutional and policy advice in selected developing countries. Through these efforts, ESMAP aims to assist governments, donors, and potential investors in identifying, funding, and implementing economically and environmentally sound energy strategies.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG), composed of representatives of the UNDP and World Bank, the governments and institutions providing financial support, and representatives of the recipients of ESMAP's assistance. The ESMAP CG is chaired by the World Bank's Vice President, Finance and Private Sector Development, and advised by a Technical Advisory Group (TAG) of independent energy experts that reviews the Programme's strategic agenda, its work program, and other issues. ESMAP is staffed by a cadre of engineers, energy planners and economists from the Industry and Energy Department of the World Bank. The Director of this Department is also the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported by the World Bank, UNDP and other United Nations agencies, the European Community, Organization of American States (OAS), Latin American Energy Organization (OLADE), and countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

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Acknowledgments

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In addition, specific studies were performed by various non-Bank consultants, including Technoplan (Brazil), Cullen & Valdez Rojas (Argentina), Synex (Chile), Liquid Fuels (CNG), and NERA (gas pricing).

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The preliminary version of the green cover report was produced in December 1992 and discussed with the Bolivian ministry in January 1993. The report has been adjusted in accordance with the final comments made by the outgoing government on August 3, 1993. The report was cleared for publication by the new government, which took office in August 1993 (comment on page xvii).

Abbreviations and Acronyms

CESP	Companha de Eletricidade de São Paulo (Brazil) (São Paulo Power Company)
CIF	cost, insurance, freight
CNG	compressed natural gas
COBEE	Compaña Boliviana de Energia Electrica (Bolivia) (Bolivian Power Company)
COCAR	Corporación del Carbon (Chile) (Coal Corporation)
CODELCO	Corporación del Cobre (Chile) (Copper Corporation)
COMIBOL	Corporación Miniera Boliviana (Bolivia) (Bolivian Mining Corporation)
CORDECRUZ	Corporación de Desarollo de Santa Cruz (Bolivia) (Regional Development Corporation of Santa Cruz)
COSERELEC	Corporación de Servicios Electricos
DINE	Dirección Nacional de Electricidad (Bolivia) (Directorate of Electricity)
EDELNOR	Electricidad del Norte (Chile) (Northern Power)
ENDE	Empresa Nacional de Electricidad (Bolivia) (National Electric Power Company)
ENEL	Ente Nazionale de Energia Elettrica (Italy)
ESMAP	Joint UNDP/World Bank Energy Sector Management Assistance Program
FOB	free on board
GdE	Gas del Estado (Argentina)
GDP	gross domestic product
GOB	Government of Bolivia
HHV	higher heating value
HSFO	high sulfur fuel oil
LPG	liquefied petroleum gas
LHV	lower heating value
LRMC	long-run marginal cost
LSFO	low-sulfur fuel oil
MEH	Ministerio de Energia e Hidrocarburos (Bolivia) (Ministry of Energy and Hydrocarbons, with new government changed to National Secretariat of Energy)
NG	natural gas
NG-eq.	natural gas-equivalent
NPV	net present value

RDC	Regional Development Corporation (Bolivia) (Corporación de Desarollo)
R/P	reserves-to-production ratio
SETAR	Sociedad Electrica de Tarija
SIN	Sistema Interconectado Nacional (Bolivia) (Interconnected Power Grid)
SING	Sistema Interconectado del Norte Grande (Chile) (Northern Interconnected Power Grid)
SSM	South-Southeast-Midwest
YABOG	Yacimientos Bolivianos Gulf Corporation (Bolivia)
YPF	Yacimientos Petroliferos Fiscales (Argentina) (National Oil Fields)
YPFB	Yacimientos Petroliferos Fiscales Bolivianos (Bolivia) (Bolivian National Oil Fields)

Units

Two sets of units are to be found in this report as far as gas volumes and flows are concerned because units vary according to the countries—for example, Brazil and Argentina use the metric system (for example., cubic meter, cubic meters per day), while Bolivia still uses Anglo-Saxon units (for example, cubic foot and cubic feet per day). Where metric units are used in the text, equivalence with Anglo-Saxon units is provided; however, tables only feature those units used in the country they deal with. As far as prices and costs are concerned, they are generally given in US$/mmBtu; however, US$/mcf is to be found when prices are actually expressed in this unit, as it is for example in Bolivia.

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})

Volume and Weight

bl	barrel	1 bl = 159 liters = 0.159 cm
bbl	barrels	
bcf	billion cubic feet	
bcfd	billion cubic feet per day	
bcm	billion cubic meters	
bcmy	billion cubic meters per year	
boe	barrel of oil equivalent	
bpd	barrels per day	1 bpd = 50 tpy (oil)
cf	cubic foot	1 cf = 0.0283 cm
cfd	cubic feet per day	
cm	cubic meter	1 cm = 1,000 liters = 35.314 cf = 6.29 bbl
cmd	cubic meters per day	
cmy	cubic meters per year	
mbbl	thousand bbl	
mbd	thousand bbl per day	
mmbbl	million bbl	
mcf	thousand cubic feet	1 mcf = 28.32 cm
mcfd	thousand cubic feet per day	
mcm	thousand cubic meters	
mcmd	thousand cubic meters per day	

mcmd	thousand cubic meters per day	
mmcf	million cubic feet	
mmcfd	million cubic feet per day	1 mmcfd = 10 mmcmy
mmcm	million cubic meters	
mmcmd	million cubic meters per day	
mmcmy	million cubic meters per year	
mmtoe	million tons of oil equivalent	
mt	thousand tons	
t	metric ton	
tcf	trillion cubic feet	1 tcf = 30 bcm
toe	ton of oil equivalent	1 toe = 1,000 cm of natural gas
tpy	tons per year	

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
GW	gigawatt	
GWh	gigawatt-hour	
HHV	high heating value	
HV	high voltage	
kcal	kilocalorie	1,000 kcal = 1.163 kWh (thermal)
kW	kilowatt	
kWh	kilowatt-hour	1 kWh= 860 kcal
LHV	low heating value	
LV	low voltage	
Mcal	megacalorie	
MV	medium voltage	
MW	megawatt	
MWh	megawatt-hour	
NG	natural gas	
TWh	terawatt-hour	

Miscellaneous

bar	bar	1 bar = 14.7 psi
km	kilometer	
psi	pound per square inch	

Rules of Thumb

1 mmcfd = 10 mmcmy
1 bpd = 50 tpy (oil)
1 tcf = 30 bcm
1 mmBtu = 1 GJ = 1 mcf natural gas (energy content)
I toe = 1,000 cm of natural gas

Calorific Values

Energy	*Unit*	*HHV (kcal/unit)*	*LHV (kcal/unit)*	*Density (oil products)*
High-sulfur fuel oil	kg	9,920	9,420	0.99
Low-sulfur fuel oil	kg	10,440	9,920	0.99
Diesel oil	kg	10,750	10,210	0.85
Naphtha	kg	11,220	10,660	0.70
Gasoline	kg	11,130	10,575	0.74
LPG	kg	11,730	10,560	0.55
Ethanol	kg	6,650	6,320	
`Natural gas	cm	9,300	8,370	
Natural gas (São Paulo)	cm	9,400	8,460	
Refinery gas	cm	6,880	6,190	
Town gas (São Paulo)	cm	4,100	3,690	
Wood	kg	3,300	3,200	
Charcoal	kg	6,800	6,600	
Steam coal	kg	4,800	4,655	
Coking coal	kg	7,920	7,680	

Executive Summary

Key Conclusions and Recommendations

1 The major conclusions and recommendations of this report are outlined below and then discussed in more detail in the remainder of this summary:

- To meet anticipated requirements for the domestic and export markets, especially to Brazil, Bolivia's proven reserves will need to be increased through further field delineation and exploration of the country's considerable potential. To accelerate this process, all exploration acreage and fields held by Yacimientos Petroliferos Fiscales Bolivianos (YPFB) should be opened to joint ventures with the private sector.[1] This would increase the efficiency of investment and also release scarce public resources for use in the social and infrastructure sectors. Moreover, this strategy would be in line with the government policy of increasing liquid resources to supply the domestic market.
- The terms for natural gas in exploration and production contracts need to be developed more thoroughly. Bolivia should formulate a model contract for exploration and production designed to attract foreign investors on equitable terms and to ensure uniformity of treatment across fields. An exploration promotion campaign should be undertaken to maximize foreign interest in acreage.
- Production planning should be improved so as to avoid wasteful flaring of gas and the excessive focus on liquids recovery at the expense of overall production optimization. A least-cost study of gas transmission development should be undertaken.
- The major issue in domestic gas utilization is the need for a proper costing of gas in power use. The present system of costing gas purely on a volumetric basis should be replaced by a costing that takes correct account of fixed and variable costs—in particular, the fixed costs of gas transmission. Proper provision for the fixed and variable costs of gas in power planning is critical if the optimal mix of hydro and gas turbine investments is to be achieved.
- Compressed natural gas (CNG) use represents an economically attractive opportunity for Bolivia that could replace a significant proportion of liquids use in transport. CNG should be developed on the basis of private sector investment, within an appropriate fiscal and regulatory framework.

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[1] The new government (in office since August 1993) plans a capitalization of YPFB, which implies private sector control over the company.

- Opportunities for the development of Bolivia's gas resources will be enhanced by the broadest possible growth and liberalization of gas markets within Cono Sur, and Bolivia should encourage current trends toward liberalized markets and growth in gas trade. The major influences within the region will be the opening of the Brazilian market and the course of events in Argentina following liberalization. Liberalization is creating a market-driven framework in which price signals will motivate more exploration and development, which, in turn, will determine the course of prices. The additional discoveries will be necessary to sustain export market growth.
- Bolivia must continue to treat Argentina as a major influence on its gas sector. The course of the Argentine market after liberalization is uncertain; proven reserves are inadequate to sustain market growth, and unless further exploration brings forth sufficient supplies, imports may be required in the long run. Bolivia should continue to view Argentina as a long-term potential market for its gas. Bolivia thus should develop capacities to enter the liberalized Argentine market as a direct supplier to end-users, and to promote policies and investments that would increase the market opportunities for Bolivian gas. This will involve dedicating staff within the Bolivian Ministry of Energy and Hydrocarbons (MEH)[2] and YPFB to the Argentine market.
- Bolivia's focus on developing the Brazilian gas market is justified. The São Paulo market is attractive in terms of potential volume and the economic value of gas. The industrial market presents a solid base for exports, but power demand will be essential for the rapid buildup of volumes. Because Bolivia does not have the proven reserves to supply the export volumes currently planned, an export scheme must be linked to a program to appraise and develop Bolivia's resources fully. In negotiating the contract terms with Brazil, Bolivia should avoid taking on an excessive share of the volume and price risk, particularly because of the large scale of the project relative to Bolivia's economy.[3]
- Schemes to export Bolivian gas to the north of Chile do not appear to be economically attractive. Although the volume of energy demand in the Chilean copper industry is substantial, Bolivian gas is unlikely to be able to compete with domestic coal from Magallanes at an acceptable price, unless substantial hydrocarbon reserves are discovered in the Western Altiplano. Similarly, liquefied natural gas (LNG) and methanol schemes based on Bolivian gas would not be internationally competitive. Bolivia should not focus substantial efforts on development of this market in the short-term.

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2 The acronym MEH is used throughout the report although with new government (August 1993) it has been changed to National Secretariat of Energy.

3 Comments about negotiations were written before signing of the exports contract with Brazil. They do not indicate any judgment by ESMAP on the final outcome of the negotiations.

- Bolivia's domestic gas pricing should distinguish between the commodity value of gas and the costs of transmission and distribution. The commodity price for gas would take into account the economic cost of gas and market conditions at a regional level. Considering that the market to Brazil is opened, prices are expected to reach a level in relation to the netback value of exports. In the unlikely event that the Brazilian market would not eventually open, a continued surplus of gas would drive prices down toward short-run marginal cost. In this case, price would reach a different level based on a pragmatic estimate of the economic cost of gas (including a depletion allowance).
- Two-part transmission and distribution tariffs should be established, with both a fixed reservation (demand) charge and a variable (usage) charge. These should be based on the cost of investment and operation of the pipeline system and administered by an independent regulatory agency (to be set up under the new legislation). Application of such a system will lead to a substantial increase in gas costs to consumers located far from the gas fields, as well as to residential and commercial distribution customers.
- To place increased institutional focus on natural gas, a single national gas transmission company should be set up through the merger of currently separate divisions of YPFB. This company, as well as the independent distribution companies, would charge economic tariffs, under the oversight of an industry regulator. It would operate as a commercially independent entity, possibly within a YPFB holding company. The regulator would permit other companies to invest in new pipelines so as to limit the monopoly powers of the transmission company. A gas marketing group should be created within YPFB to improve the effectiveness of gas supply planning and to sell gas through the transmission companies. MEH's capacity to manage the gas industry must be strengthened through provision of more manpower. Consumers, particularly Empresa Nacional de Electricidad (ENDE), should be encouraged to take a more active role in the gas market.

2 The World Bank and ESMAP will continue to address these issues in their work in Bolivia. ESMAP's continuing program in Bolivia will emphasize the further elaboration of gas policies in critical areas, as well as wider hydrocarbon pricing reform. The Hydrocarbon Sector Deregulation, Restructuring, and Engineering project to be supported by the World Bank will be the vehicle for many of the reforms recommended in this report.

3 The new Bolivian government (in office since August 1993) notes that because this report was basically finished in 1992, it is not fully updated on all developments. The issue of potential export of Bolivian LNG by means of a terminal in Chile has not been addressed; likewise, the potential for gas sales to Paraguay has not been assessed in the report. Finally, the report does not discuss the use of gas as a petrochemical feedstock, which had been addressed earlier in separate studies made for the Bolivian government.

Natural Gas in the Economy

4 Natural gas plays a key role in Bolivia's economy although this role has diminished some over the later years. Oil and (primarily) gas has until recently contributed about 50 percent of the exchequer's revenues, and absorbed about 40 percent of public investment. In 1992, natural gas exports (US$125 million) accounted for 18 percent of total merchandise exports following a downward trend in relative terms since 1985 (55 percent) and in absolute revenue terms since 1990. Bolivia's macroeconomic stabilization program has been highly effective in reducing inflation and containing internal and external imbalances. A fundamental feature of the government's economic strategy is to remove the constraints to private sector investment, improve public sector management, and shift public investment from the productive sectors to social sectors and infrastructure. An important part of the process of economic reform includes improving the management and utilization of the nation's gas resources and increasing the private sector contribution to investment in this subsector, thereby releasing public funds for use in the social sector.

5 A fundamental concern of the Bolivian government has been to avoid the need for large imports of liquid fuels, with the associated foreign exchange costs and loss of government revenues that this would imply. The supply and demand of fuels have been precariously balanced in recent years, largely because most hydrocarbons discovered have been in the form of natural gas. The fundamental government policies regarding hydrocarbons have thus been aimed at ensuring an increase in liquid fuel reserves by encouraging investment in exploration and production. This has required a focus on finding new markets for natural gas, principally by developing markets in neighboring countries.

Exploration and Production

6 Bolivia's natural gas reserve base of 6.4 tcf (proven and probable) is substantially in excess of domestic requirements. Because the known hydrocarbon-bearing areas of the country are gas prone, continued exploration is increasing gas reserves relative to liquids reserves (the proportion of gas in total discoveries rose from 71 percent in the 1960s to 88 percent in the 1980s). In contrast, proven liquids reserves of 187 mmbbl are only just adequate for domestic demand.

7 The key issue for Bolivia in the exploration area is how to balance priorities between exploration for liquids and gas. A number of points require particular attention in this respect:

- First, despite the known surplus of reserves, continued delineation and accurate appraisal of gas reserves is important to reinforce export marketing efforts. In the context of the gas-power export project to Brazil, recent certification of reserves in Bolivia by foreign consultants resulted in a downgrading of proven reserves in the major YPFB fields by 14 percent, indicating inadequate appraisal by YPFB.

- Second, it is evident that Bolivia will need to exploit its potential for discovering additional reserves in order to capture the full potential of regional markets in the long-term. In particular, the plans for export to Brazil will require larger proven reserves if the full benefits of scale economies in pipeline transport—and the full potential of the demand of the São Paulo market—are to be captured.
- Third, because Bolivia's liquids supply situation is precarious, continued exploration is vital if domestic self-sufficiency is to be maintained. Bolivia's landlocked position and poor communication links would make oil imports relatively expensive, given the overall deficit in the region. Nonetheless, in the "Traditional," well-explored areas, the chances of finding oil fields, as opposed to gas fields with some associated liquids, are relatively small.
- Finally, much of the country remains unexplored, with only 17 percent of the sedimentary area properly surveyed and drilled. The unexplored basins present possibilities of major gas or oil discoveries, but exploration will naturally be high risk. Assessing the full hydrocarbon potential of the country must be a major national priority, given the potential impact of major discoveries on the national economy and Bolivia's generally limited options for highly profitable export-oriented investments.

8 Policies that address these priorities must cover a number of areas: First, more resources must be put into appraising the full potential of the traditional areas. These are currently dominated by YPFB, which lacks the financial and technical means to assess them fully. The opening up of all of YPFB's fields to joint ventures with private companies is vital if the full potential of this area is to be developed. This will also release scarce public funds for investments in other areas. Second, an aggressive exploration campaign of the unexplored areas must be initiated attracting the best international companies to this task. Given YPFB's limited financial and technical resources, sole-risk exploration by YPFB should be discontinued. Moreover, the practice of borrowing for exploration is unusual and should not be encouraged. To date, there has been some notable progress in this respect, with several significant contracts signed with foreign companies. Nonetheless, actual cash and work commitments by companies have been modest. To some extent, this reflects the lack of a coordinated exploration promotion effort by the government.

9 A key issue that needs to be addressed is the formulation of a proper framework for natural gas exploration and production by foreign companies. In a gas-prone country such as Bolivia, the perception of risk by foreign companies will be intimately connected to the potential profits they may reap from gas discoveries. One consideration in the profit scenario is marketability, and in the Bolivian context, the development of export markets is a key. Even where markets do open up, however, companies must believe that they will receive acceptable value for their gas in the event of a discovery. Hence, the terms of exploration and production contracts are critical. Unfortunately, Bolivia's approach to this question still leaves much to be desired. In particular, the definition of commerciality needs clarification; the timing of

commerciality and development decisions should be adjusted to provide more generous holding periods for gas discoveries; the rights of companies to market their own gas and to access pipelines should be better defined; fiscal terms for natural gas could be revised to allow a greater differentiation from oil; and clearer signals should be provided based on more rational domestic and export pricing. In addition, Bolivia's royalty-based fiscal regime should be reviewed, because it does not capture rent effectively from large profitable developments and may deter marginal developments (particularly of gas fields). Finally, the lack of uniformity of gas terms makes it difficult to reconcile economic priorities with fiscal priorities—the most economic gas field may not always be the one yielding the best revenues to the government. Progress has been made through a project (supported by UNDP funds) to foster development of new regulations under the Hydrocarbons Law.

10 Many of the problems of exploration carry over into the production area. The key problem here has been the lack of effective production planning by YPFB. There has been insufficient attention to the economics of liquids recovery from gas fields, and pressures on YPFB to maintain liquids production have led to significant flaring where gas reinjection or processing facilities have not been available. In addition, it is not clear that production operated by private contractors, which accounts for 36 percent of the total, is effectively integrated into overall production planning.

11 Urgent priorities to address include the following: First, a model contract for exploration and production should be developed that incorporates appropriate terms for natural gas and more effective fiscal structures and that brings uniformity to different field developments so as to promote development of the fields along economic lines. Second, all areas, including those held by YPFB, should be opened to foreign investors so as to bring greater financial and technical resources to bear; this should be coupled with an exploration promotion campaign and development of a strategy prioritizing the overall exploration and appraisal effort across the country. Finally, a regulatory regime for gas should be enacted, governing such areas as pipeline access and tariff setting.

12 The key issues in natural gas transmission concern the institutional organization of this activity. The present division between the YABOG and YPFB organizations is not conducive to optimal system planning and operation. The different characteristics of the two organizations—that is, YABOG is dedicated to running a large gas export pipeline, and YPFB manages a small, but complex gas transmission system along with oil pipelines—also lead to a lack of coherence. Creation of a single company to handle all gas transmission would clearly be beneficial.

13 YPFB would benefit from inputs by an experienced pipeline consultant in planning the expansion of its pipeline network. The current expansion plans do not appear to represent the most efficient and cost-effective way to expand the capacity of the network. It is also important that YPFB's transmission planning be closely integrated with demand developments (particularly ENDE's plans) and with gas resource development. Clear, market-related interfaces between gas consumers and producers and the pipeline operators should be established by developing dedicated gas purchasing and

marketing staff among consumers and producers and by using gas transportation contracts that would allow the transmission company to plan its investments and operations.

Domestic Gas Utilization

14 After power, the industrial sector is the main consumer of natural gas in Bolivia, accounting for 43 percent of demand. Bolivia has been successful in expanding gas distribution to all the major industrial centers of the country, and it is estimated that natural gas has now taken about 80 percent of its potential market in the industrial sector. Nonetheless, there is strong potential for demand growth, based on the expected future growth of industrial activity and on an increase in capacity utilization in key industrial areas such as metallurgy and mining. Average demand growth is expected to be about 7 percent per year until 2010. Despite the success of gasification of industry, YPFB has not optimized its distribution investments and marketing. The private-public distribution companies in Bolivia should focus on developing a closer understanding of each customer's potential demand and conversion needs to maximize future investments. The introduction of appropriate two-part tariffs for gas, as discussed below, is also indispensable for rationalizing gas use in the sector.

15 In the power sector, the key investment issue facing Bolivia is the optimal choice between hydro and natural gas in power generation. To date, investment has been characterized by exclusive use of hydro in most of the West of the country (away from the gas fields) and exclusive use of gas in the East (near the fields). The generation mix in the central area, around Cochabamba, has the potential to be more mixed, with hydro and gas options competing.

16 The appropriate pricing of gas for power is critical to investment decisions, as well as for short-term operating decisions. In Bolivia, pricing has been giving misleading signals to power planners because of the exclusive use of variable costs. Charges for gas in planning and operation are volumetric (that is, they are charged on a per unit basis), with no fixed capacity cost. However, the correct price signals for gas should be reflected in a fixed transport charge incorporating the capital cost of the pipelines, a variable charge reflecting operating costs, and a commodity charge for gas reflecting its market value. In the case of power, the use of variable rather than fixed costs tends to distort relative investment decisions between hydro plants, where nearly all costs are fixed, and gas turbines, where the fixed cost per unit capacity is relatively low. Where the gas for a turbine has to travel through a substantial pipeline, the fixed cost of the pipeline needs to be added to the fixed cost of the turbine, altering the comparison with hydro.

17 The investment distortions are particularly acute in the case of the mixed hydro-thermal (gas) systems that exist in some areas of Bolivia (for example, Cochabamba). In these areas, the plant factors of gas turbines are low, because they are used to compensate for inadequate hydro output during the dry season and are also used

as supply security in case of drought years. However, the true cost of maintaining idle turbine capacity is not captured by a variable gas charge; there is thus likely to be overinvestment in turbine capacity as opposed to hydro capacity. An additional complication is introduced by the consideration of combined-cycle plants as an alternative to additional hydro or turbine capacity, particularly since there is the possibility of adding steam units to existing turbines. In this case, the fixed costs of such units will be reduced relative to new open-cycle turbines, because they will not require more pipeline capacity.

18 It is vital that future power planning takes into account two-part pricing for gas. This should be accompanied by the introduction of such pricing for actual use, as recommended below, to ensure efficient system operation and cost-recovery for pipelines. It should be recognized, however, that some allowances may need to be made in the initial tariffs, given that past investment decisions are likely to have been suboptimal and full recovery of pipeline costs may not be possible in the future.

19 Using compressed natural gas (CNG) in transport vehicles represents another important potential use for natural gas in Bolivia. An analysis shows that this is an economically attractive option for Bolivia and that a market for about 180 mmcm per year of CNG could be built up within 10 years, replacing 140,000 tons of gasoline (about 50 percent of national consumption). It is recommended that CNG development be undertaken by the private sector. To encourage private investment, however, it will be necessary to develop an appropriate regulatory and pricing framework. The government has been developing such regulations. Quality assurance, bolstering consumer confidence, and targeted marketing of CNG are also important. Private investors will need to earn relatively high rates of return in the early years, to reflect the risks being taken, although rates of return could be reduced as the market is developed.

Natural Gas Exports

20 Bolivia's export prospects for natural gas must be seen within the context of gas development within the whole Southern Cone (Cono Sur) of Latin America. The Cono Sur is a region that may have considerable potential for regional gas trade. Demand potential for gas is high, particularly in view of the growing attractiveness of gas in combined-cycle power generation. A number of areas with major potential demand but limited supply exist in Brazil, Chile, and Uruguay. Gas surpluses exist in Bolivia, parts of Argentina, and southern Peru. Within the region, Argentina dominates the current supply and demand picture for gas, and Brazil dominates the future consumption potential. The development of the Brazilian market and the course of the Argentinean supply-demand balance are thus the two dominant factors in the future development of gas in the Cono Sur.

21 An important trend within the region is the growing liberalization of gas markets, which is being led by the privatization of Gas del Estado in Argentina. This development is encouraging new projects to come forward, and it stimulates the

involvement of private capital. On the other hand, the eclipse of the traditional leaders of the industry—the state companies—is creating a vacuum in project leadership.

22 A number of projects, at various stages of consideration, could eventually lead to an interconnected gas market in the region. These include links from Bolivia to Brazil and Chile and from Argentina to Chile, Brazil, and Uruguay. Currently, the most serious contenders for early development are the Bolivia to Brazil link (São Paulo) and the Argentina to Chile link (Santiago). An analysis of the regional reserve base suggests, however, that proven reserves are inadequate to sustain demand growth in both existing and new markets. A consensus exists that potential reserves exist to satisfy this demand, but, to date, exploration has been held back by the perceived lack of large local markets, poor gas prices, dominance by underfunded state companies, and general political and economic uncertainty.

23 With growing liberalization, the potential exists for market-driven development, in which market signals (including higher prices) drive private projects owing to more open access to markets and exploration opportunities. In this context, three possible scenarios can be envisaged: (a) *low case,* in which few new markets are developed owing to a lack of market-driven investment, (b) *mid case,* in which new markets are opened in a gradual manner; and (c) *high case,* in which there is explosive growth of demand in the region with rapid investment. Currently, it is difficult to predict which of these cases will come about because of continuing uncertainties over institutional development and the lack of clarity as to whether supplies will be adequate, particularly to meet the high-case demand. The future level of prices in the region will be set by the costs of marginal deliveries to the main consumption centers. If sufficient reserves are discovered in areas with low marginal delivery costs (for example, Neuquen) prices will be held down. A failure to find adequate reserves in low-cost areas will push prices up to a level needed to justify deliveries from high-cost areas (for example, Austral).

24 For Bolivia, the primary strategy must be to encourage the most dynamic possible regional development, based on market forces. The opening of the Brazilian market will create strong incentives for increased investment upstream, provided adequate terms and access are given to international investors in exploration and production.

25 Argentina accounts for 80 percent of Bolivian gas sales and remains the major influence on the prospects for Bolivian gas in the short-term. Given the structural changes in the Argentine market and the uncertainties over Cono Sur developments in the longer term, it is vital for Bolivia to sustain its strong links with the Argentine market so as to preserve the option of continuing export to Argentina.

26. Despite having one of the highest gas penetration rates in the world, the Argentine gas market still has substantial room for growth. Total demand is expected to grow by about 3.5 percent per year over the next 10 years. A key factor driving this growth will be the power market, where gas combined-cycle plants are likely to take over

from hydro and steam plants as the generation source of choice from the late 1990s (once hydro plants under construction are completed).

27 Argentina's gas reserves at present appear insufficient to meet the growing domestic demand in the long-term. The gas potential of the country has not been fully explored, however, because of the inadequate resources of the dominant state company, Yacimientos Petroliferos Fiscales (YPF), and limited incentives to private producers in the past. In the short run, supplies are adequate to meet demand, even without Bolivian imports. With growing demand, however, the long-term requirement for imports from Bolivia (which currently account for 12 percent of total supply) is uncertain.

28 The regional transport and supply situation in Argentina will have an important effect on Bolivia's prospects in the market. All pipelines are operating at capacity, especially during the winter peak, and the pattern of future supply will be driven by the development of new transport capacity. The current oversupply of gas in the North, caused by inadequate capacity in the northern pipeline taking gas from Northern Argentina to Buenos Aires, is likely to continue in the medium-term. Incremental supplies to the main markets are most likely to come from the Neuquen, where expansion of transport capacity is lowest cost. The greatest long run supply potential is probably from the South, but incremental transport costs are highest from this region.

29 The liberalization of the Argentine gas industry, against this complicated supply-demand background, makes forecasting of market prices and dynamics particularly difficult. The privatization and fragmentation of Gas del Estado creates a competitive market for gas supplies in Argentina and open access for all producers, including Bolivia. This restructuring has necessitated the renegotiation of Bolivia's gas export contract of May 1992. Bolivia has been able to obtain some security for its exports by negotiating the right to continue with previous exports of 6.1 mmcmd (215 mmcfd) until 1997, but at a price of only US$1.00/mcf (about 40 percent of previous prices) until December 1993, and market prices thereafter. Given the oversupply of gas in the north of Argentina, there is a risk of continued low prices in the longer term.

30 The current uncertainties in the regional market mean that Bolivia should continue to view Argentina as a long-term potential market for its gas. Although the focus on opening up the Brazilian market is of course important, Bolivia must therefore continue to give close attention to developments in Argentina. This should include dedicating staff in MEH to monitoring the gas situation in Argentina. Also, YPFB staff should be assigned to marketing gas directly to Argentine consumers to take advantage of market opportunities. Bolivia should also be ready to intervene to lobby for changes in the Argentine market that will maximize market opportunities for its gas, including expansion of the northern pipeline, the development of gas in power generation (through independent power projects), and possible export to Chile under a swap arrangement. Integration of Bolivia's system with Argentina's should also be considered with regard to using the substantial gas storage in Bolivia (especially Rio Grande) to assist seasonal swings in Argentina, and additional pipeline links between the two countries could be created as well. In the longer term, the potential for reversing the existing line from

Argentina to Bolivia for integration with Bolivian exports to Brazil could become important under certain scenarios.

31 Brazil presents, by far, the largest market opportunity for Bolivian gas exports. Brazil's energy resources consist largely of hydropower, woodfuels, and biomass (ethanol from sugar cane). These fuels have substantial environmental problems, economic drawbacks, or both. Brazil's petroleum resources, particularly of natural gas, fall far short of its potential requirements. Proven reserves of natural gas were 4.7 tcf in 1993, a figure similar to that in Bolivia, despite the fact that commercial energy consumption in Brazil is about 75 times that in Bolivia. Prospects for new gas discoveries in Brazil in areas close to existing markets, and on a scale that would supply most of the available demand, are considered limited. Gas sales by the monopoly supplier, Petrobras, were 7.6 mmcmd (268 mmcfd) in 1990, and sales by 2001 are projected at between 20 mmcmd and 47 mmcmd (706 and 1,660 mmcfd). (The upper end of this range is optimistic in the light of performance to date.) Moreover, only about half of these supplies will be available for the South and Southeast regions, which are accessible to Bolivian gas. Much of this will be used in the Rio de Janeiro area rather than in the Bolivia's prime target market of São Paulo.

32 The State of São Paulo represents one of the most concentrated areas of energy demand in the developing countries. With 31 million inhabitants (21 percent of the national population), this area accounts for 38 percent of the total economic output of Brazil. Primary energy use in 1988 reached 44 mmtoe, or 20 times that of Bolivia. Energy supplies from oil and biomass make up most final energy supplies, with attendant pollution problems in many areas. Yet natural gas supplies to this market are minimal, consisting of only 0.85 mmcmd (30 mmcfd) in 1992.

33 Under realistic assumptions about market penetration and assuming that Bolivia can start exporting to Brazil in 1997, the market for Bolivian gas in São Paulo state can be expected to grow from 5.5 mmcmd in 1997 to 16 mmcmd in 2000 and 25.7 mmcmd in 2010. Demand for this gas is likely to come from all sectors:

- The large industrial sector of São Paulo provides a solid base market for natural gas. A large part of the potential market (54 percent of substitutable consumption) is accounted for by fuel oil. The substitution of gas for fuel oil in heavily industrialized areas will bring substantial environmental benefits. This market accounts for some 12 mmcmd (47 percent) of potential demand by 2010. A further 1.4 mmcmd (5 percent) could come from cogeneration projects.
- Power generation represents a major opportunity for Bolivian gas. The lower-cost options for hydro supply to São Paulo have been largely exhausted, and there are also environmental problems with new schemes. Under current demand scenarios, there is a risk of a shortfall in power supplies by the turn of the century. Combined-cycle plants in São Paulo offer an economical and environmentally acceptable alternative. Conversion of existing fuel oil plants in São Paulo to

combined-cycle operation, and construction of new facilities, could together bring demand of 9.7 mmcmd from 2001 onward (38 percent of 2010 potential).

- Other potential markets include both the residential and commercial sector and compressed natural gas. In the former, town gas is already distributed to 219,000 residential and 4,900 commercial customers, and a project is under way to double this customer base through addition of natural gas supplies. The size and wealth of the population of São Paulo mean that demand could reach a significant 1.1 mmcmd (4 percent of the market) by 2010, despite low specific consumption because of the absence of space heating. CNG schemes are already planned for the city to alleviate pollution, and demand could reach 1.4 mmcmd (5 percent of the market) by 2010.

34 An analysis of netback values for gas shows it to have an attractive value at the city gate for most sectors. In the industrial sector, the netback from fuel oil is relatively low; this is partly offset however, by the much higher substitution value of electricity currently used for thermal applications, giving an overall economic city gate value of US$3.45/mmBtu based on economic values of fuels. Although the selling prices of oil products in Brazil are close to economic cost, electricity is underpriced, which reduces the netback at market prices to US$2.63/mmBtu. With regard to power generation, gas in combined-cycle stations has an attractive plant gate (city-gate equivalent) value of US$3.07/mmBtu, based on the economic costs of alternative hydro supplies. Netbacks are also relatively high for the residential and commercial sectors, at US$6.84 to US$8.59/mmBtu, because of the high costs of electricity and LPG. Gas is similarly attractive for CNG use with a netback of US$6.07/mmBtu (in part because of the high economic cost of ethanol).

35 Having signed an agreement to export gas to Brazil, Bolivia faces a number of crucial issues in bringing the project to fruition. First, it is evident that Bolivia will need to prove additional gas reserves to sustain projected export volumes as well as domestic demand in the long-term. This emphasizes the importance of linking the export project to an intensive program of reserves appraisal and further exploration that must involve foreign private companies in all areas. Bolivia's exploration potential suggests that such a program should succeed in finding the required reserves. Second, the apportionment of risks in gas sales contracts between Bolivia and Brazil will be another key issue for Brazil because the importance and urgency of the export project is greater for Bolivia than for Brazil. Thus, there is a possibility that Bolivia would have to accept a disproportionate share of price and volume risk, having negotiated from a position of weakness. Careful attention to this will be required as sales contracts are developed, and, by obtaining expert advice, account should be taken of experience with similar projects elsewhere. There are also a number of institutional and structural issues that will need to be resolved within Brazil, in particular, the appropriate role of Petrobras.

36 Although northern Chile has long been viewed as a potential market for Bolivia's gas, an analysis of the energy market and fuel supply situation in the region suggests that there may be limited potential for sales of gas at attractive prices in the

foreseeable future. Energy demand in the region is dominated by Chile's world-scale copper industry, which requires fuel oil both for direct energy uses and for large power supplies. The fuel oil could be substituted at a relatively attractive price. This market accounts for only about 18 mmcfd at a gas-equivalent price of up to US$3.00/mmBtu. The bulk of energy requirements are for power generation, with the 400 MW Tocopilla thermal station owned by the state copper company (CODELCO) accounting for about two-thirds of the substitutable energy consumption in the region. The needs of Tocopilla are supplied mainly with sub-bituminous coal from the extreme south of Chile. This coal was developed especially for Tocopilla and is sold under a long-term contract expiring in 1998. The current price of local coal is equivalent to about US$2.10/mmBtu, but the actual average costs of the coal are probably as low as US$1.30/mmBtu, and operating costs may be only US$0.70/mmBtu. Inasmuch as delivery of gas from eastern Bolivia would require construction of a 1,100 km pipeline, at a cost of around US$450 million, an average transportation tariff of US$1.50/mmBtu would be required. It is thus unlikely that Bolivian gas could displace Chilean coal in power.

37 Without substitution at Tocopilla, the market for Bolivian gas would be limited to about 1.5 mmcmd of fuel oil replacement at a value of around US$3.00/mmBtu. This volume is insufficient to justify a pipeline from Bolivia. It is also clear that LNG and methanol export schemes based on Bolivian gas would not be internationally competitive. This suggests that unless there are important hydrocarbon discoveries in the western Altiplano, Bolivia would be unwise to devote substantial resources in the near future to developing gas sales to northern Chile, which would divert scarce manpower from the Argentine and Brazilian market opportunities. One option that could be explored in the medium-term is to sell Bolivian gas to Chile through a swap between Bolivian gas in northwest Argentina and Argentine gas from the Neuquen (which is planned to be sold to Santiago).

Natural Gas Prices and Tariffs

38 A fundamental aim of natural gas policy must be to establish an economically rational system of gas pricing. From the point of view of economic efficiency, it is vital to distinguish between the *commodity value of gas as a fuel,* which should be determined in relation to market forces within the overall energy market, and the *cost of transmission and distribution,* which is determined by the investment and operating costs of pipelines. Thus, two separate issues must be considered in determining natural gas prices: first, the price to be put on gas at the entrance to the transmission system, and second the tariffs to be charged for transmission and distribution. Currently, gas pricing in Bolivia includes both commodity value and transport costs within a single price, which is not determined in relation to either economic value or costs.

39 Gas price setting should be a pragmatic exercise. Theoretically based estimates of the economic value of gas should be taken into account in setting prices, yet such estimates are sensitive to assumptions about future reserve discoveries and alternative fuel costs. The approach recommended here for the commodity value of gas

takes into account both estimates of the economic value of gas and the realities of the gas industry in a regional context. It is equally the case that the tariffs set for transmission and distribution of gas, although based on actual costs incurred and principles of economic efficiency, inevitably must deviate from the ideal levels both for reasons of expediency and market imperfections (for example, sunk costs, accounting conventions, and taxation).

40 The economic value of natural gas is a basis for determining its commodity value. It must incorporate both the long-run marginal cost (LRMC) of exploration and production and any depletion allowance that must apply to the use of natural gas. The LRMC of production of natural gas in Bolivia is relatively low. This is because nearly all natural gas is found in association with significant quantities of liquids, and the costs of exploration and development can be recouped through the value of liquids production. Estimates from several sources suggest that the LRMC of natural gas at the wellhead is probably no higher than US$0.25/mcf. Of course, this does not necessarily represent a viable basis for setting prices; in particular, it may not attract the private risk capital the industry requires.

41 The depletion allowance element of economic cost is highly sensitive to assumptions about future reserves discoveries and fuel prices. The value of the allowance in 1992 could vary between US$0.03/mcf and US$0.73/mcf, depending on the level of future discoveries assumed. It is clearly important to incorporate a positive depletion allowance in setting gas prices, yet the size of allowance assumed depends on the risk the country is prepared to accept. The risk is reflected in the degree of optimism about future discoveries. The more conservative the approach to risk, the higher the allowance. In the case of Bolivia, it would be prudent to take a relatively risk-averse approach to assumptions about future discoveries, because of the key role of gas in the economy and the potential for economic damage through underestimating the value of gas. The depletion allowance assumed for gas pricing and planning purposes should, of course, be adjusted as information about the reserve base improves.

42 The commodity value of gas should also be set in relation to developments in the regional market. Two scenarios can be envisioned: one in which the market to Brazil is not opened, and gas-to-gas competition drives prices down to low levels. In this case, prices should be set in relation to economic costs (LRMC plus depletion allowance; e.g., US$0.50/mcf), and a second in which the opening of a pipeline to Brazil creates a tighter market, with the higher price set at the margin in relation to the netback from Brazil. A further factor to take into account is the likely increased linkage in future between a liberalized Argentina market and Bolivia's market, with market conditions in Argentina directly affecting the value of gas in Bolivia. Finally, gas pricing must take account of the need to compete for scarce exploration and production capital from the private sector with other countries in the region and elsewhere.

43 The aim of policy in Bolivia should be to move toward a market-based system of gas pricing. However, the realities of YPFB's dominant position mean that for

a transitional period the MEH may continue to need to set natural gas prices at the wellhead.

44 To encourage economic efficiency, it is important to establish transmission and distribution tariffs that cover the long-run marginal cost of gas transport, taking account of the financial requirements of the pipeline utilities. The most efficient tariff design for gas transport and distribution is the two-part tariff. The first portion of the tariff is an initial reservation (demand) charge that a customer pays to guarantee delivery of gas. The fee varies with the amount of deliveries reserved (usually expressed as a daily volume), but not with actual deliveries. It generally reflects long-term capital costs. The second charge is a volumetric usage charge that is levied on each unit of gas actually delivered. The volumetric charge generally reflects short-term operating expenses.

45 Calculations of transmission tariffs for different areas of the country show that there are relatively high costs associated with the transport of gas to areas with modest loads that are located far from the gas fields (for example, La Paz, Tarija). These costs are presently not reflected in the charges to customers, such as ENDE. In the case of distribution tariffs, it is clear that the prices previously set for commercial and residential customers do not reflect the full cost of gas distribution.

Institutional Issues

46 Bolivia's hydrocarbon sector suffers from serious institutional deficiencies that affect both oil and gas. These derive from a combination of factors, including weak government oversight of the sector, excessive government dependence on taxation of hydrocarbons rents, an ad hoc pricing system for hydrocarbons based on revenue requirements rather than economic costs, and the de facto monopoly over the industry of an inefficient YPFB. These problems are mirrored in the institutional approach to the natural gas subsector. In this area, Bolivia lacks the strong institutions required to give focus to natural gas. Bolivia's hydrocarbon industry thus remains focused on oil, despite the predominance of gas in the country's reserve base.

47 As mentioned, the current gas industry structure is marked by the de facto monopoly of YPFB over transmission and wholesale marketing. Private companies produce 36 percent of natural gas but have a limited role in its disposal. Although the majority of the final distribution is now out of the hands of YPFB, the current independent distribution companies remain weak. YPFB still markets a significant volume of gas to end-users through its direct sales to ENDE and plays a role in cities without independent distributors. Consumers have a limited direct role in the market, being passive receivers of utility gas supplies.

48 Within YPFB, there is no organizational focus on gas, despite the fact that it accounts for 80 percent of combined hydrocarbons production on an energy-equivalent basis. Responsibility for natural gas transmission lines is split between separate directorates in Cochabamba (where it is combined with oil pipelines) and Santa Cruz,

which results in a lack of overall coordination of the system. There is no overall gas supply or marketing coordination function. Within MEH, responsibility for natural gas and oil are shared by the same senior official, and there is little supporting staff that can focus on gas.

49 Reforms are required in two areas: establishment of a proper regulatory framework for natural gas and institutional reform to create an efficient industry within this framework. As regards the former, the government has (with ESMAP assistance) drafted and put forward a Natural Gas Code that embodies many of the basic principles of public sector regulation required for increased efficiency.

50 Concerning institutional reform, the most urgent action required is the creation of a single national gas transmission company to operate all the gas trunk lines in Bolivia. This company should be independent of YPFB's other operations, charging regulated arm's length tariffs to both YPFB and private producers without discrimination. The right of other companies to build transmission lines, subject to regulatory approval, should be maintained. Within YPFB, a gas marketing unit should be created that would function as a seller of gas into the regulated pipeline system, in competition with private companies.

51 Because much of the gas marketed in Bolivia goes for export, the institutional structure here is especially important. It must be accepted that for the time being the government, through MEH, will have a significant role in structuring deals and contracts, because of the national strategic nature of the trade. The actual gas export projects and the marketing of gas through the pipeline, however, could be done by a joint public-private venture. It is particularly important that continued attention be paid to marketing in Argentina in the short-term and that a viable structure be set up to create future incentives to market efficiently to Brazil.

52 In terms of the upstream segment, any increase in export markets should make it possible to attract private companies into all or most of YPFB's gas production. This will help to provide needed investment funds and to improve the efficiency of technical and commercial operations.

53 MEH's capacity to deal with gas issues needs to be increased through additional staffing and budgeting for expert advice (which could be provided through continued overseas technical assistance).

54 The distribution companies need to be strengthened by attracting capable international partners with the technical and financial resources required to further develop distribution systems, especially for the residential and commercial sectors. On the consumer side, ENDE should make its participation in the gas market more active by appointing dedicated staff to deal with gas purchases.

1

Background

Energy and the Economy

1.1 Bolivia's economic stabilization program, implemented after hyperinflation exceeded more than 20,000 percent during the first nine months of 1985, was highly successful in reducing internal and external imbalances. Interest rates were freed; foreign exchange controls, import restrictions, and price controls were eliminated in almost all markets; and prices of public sector goods, including energy, were adjusted to market levels. In the energy sector, the government strengthened the power company, Empresa Nacional de Electricidad (ENDE), with a capital infusion of US$107 million to reverse the financial weakening caused by hyperinflation.

1.2 Despite these changes, Bolivia's large public sector dominates many sectors of the economy, even though the production of many goods could be provided more efficiently by the private sector. As of 1991, Bolivia had about 159 nonfinancial publicly owned companies. Of these, about half were directly responsible to the central government, and the other half were under the nine regional development corporations. Yacimientos Petroliferos Fiscales Bolivianos (YPFB), the national petroleum company, is the largest of these enterprises; it accounts for 53 percent of the total revenues, 68 percent of the investments, and 93 percent of the total net transfers to the government generated by public enterprises. In 1992, the government initiated a program to privatize many of the public enterprises.

1.3 GDP growth during 1987-1990 was modest, at an average of 2.7 percent a year. Although growth accelerated in 1991 and 1992, the challenge for the remainder of the 1990s will be to secure the transition from low-growth stabilization to more vigorous growth and greater social equity.

1.4 Recently, the government has stated its intention to maintain its program of economic stability while pursuing the following goals:

- Reducing constraints to private sector growth, particularly by streamlining regulatory policies and improving infrastructure

- Reducing financial sector constraints to growth as a means of increasing resource mobilization, particularly from the private sector
- Improving public sector management to encourage needed investment, increase public savings, reallocate public investments away from the directly productive sectors, and strengthen basic infrastructure
- Reorienting public expenditures toward basic health and education services for the poor.

1.5 In this context, the energy sector plays a critical role in Bolivia's economy. Oil and (primarily) gas has until recently contributed about 50 percent of the exchequer's revenues, and absorbed about 40 percent of public investment. In 1992, natural gas exports (US$125 million) accounted for 18 percent of total merchandise exports following a downward trend in relative terms since 1985 (55 percent) and in absolute revenue terms since 1990. The sector has, nevertheless, a growth potential: electricity coverage is only about 30 percent, overall energy consumption per capita is one of the lowest in the continent, and biomass still accounts for about 34 percent of energy consumption (80 percent in the rural sector). Moreover, the country has substantially underutilized natural gas and hydropower potential. Hence, the energy sector's role in the overall process of the economic development will remain critical.

Energy Supply and Demand

1.6 The country's commercial energy resources are liquid hydrocarbons, natural gas, and hydroelectric power. Noncommercial energy sources consist of biomass and solar and wind energy. Proven liquid hydrocarbon reserves are 187 mmbbl, enough to sustain the local market for 14 years. All proven reserves of liquid hydrocarbons are now in production; even assuming all the probable reserves are proven and put into production, reserves will be exhausted, however, by about 2012, unless new discoveries of oil or gas fields are made (most liquids production is associated with natural gas).

1.7 Natural gas represents 68 percent of primary energy supply and 76 percent of commercial supply, excluding biomass. Proven reserves are about 4.0 tcf (800 mmboe), and probable reserves are 1.9 tcf (360 mmboe), or six times the reserves for liquid hydrocarbon. Production in 1992 was 534 mmcfd, of which 17 percent was domestically consumed for final use and for electric power production; 40 percent was exported; and the remaining 43 percent was reinjected, consumed in petroleum operations, flared, or vented. Only a small part identified potential for hydroelectric power of 18,000 MW has been developed.

1.8 Bioenergy (bagasse, woodfuel, dung) represents 34 percent of the country's total energy use and 80 percent of energy use in rural areas. About 10 to 20 percent of rural households have access to electricity. Most nonelectrified households use candles or wick kerosene lamps for lighting, although liquefied petroleum gas (LPG) or pressurized kerosene lamps would be more efficient. Supply of LPG and kerosene is relatively efficient, although preliminary analysis from ESMAP's Household Energy

Strategy study indicates that use of LPG could become more widespread if the LPG bottling system, which is wholly owned and operated by YPFB, were more decentralized.

1.9 Because of deforestation and erosion that result from using bioenergy sources, the government plans to encourage substitution by commercial energy. This substitution would be economical, however, for only about 30 percent of rural households in the case of rural electrification, mainly in the relatively concentrated rural agglomerations. Solar energy has only limited use, mainly in agriculture, principally for grain drying, greenhouses, and irrigation pumping.

1.10 The share of natural gas in energy demand has been rising, as gas has substituted for oil in industry and power. Aggregate energy demand is expected to increase by about 2.7 percent a year for the next 10 years. By subsector, electricity demand is expected to grow by about 6 percent a year, petroleum products by 3.5 percent, and natural gas by 12.7 percent; bioenergy will decline because of substitution by commercial fuels.

1.11 The projected demand assumes energy prices set by the government based on a cost-plus formula and as a function of economic requirements, power tariffs based on rate-of-return regulation, and an increased end-use energy efficiency of 10 percent. These conditions may change, because studies, recommendations, and policy reforms could alter the composition of projected demand.

1.12 In the petroleum subsector, the expected demand of 27,000 bpd by the year 2000, compared with YPFB's median projected production level of about 31,000 bpd, creates the need for the following actions: on the demand side, it would be necessary to increase efficiency of use and economic interfuel substitution; on the supply side it will be necessary to increase oilfield exploration and development.

Institutional Organization of the Sector

1.13 Under the current institutional organization, the energy sector is managed by the Ministry of Energy and Hydrocarbons (MEH)[4], which executes government energy policy. MEH is nominally responsible for formulating national energy policy and for regulating and coordinating the sector's activities. In reality, significant aspects of formulating and executing energy policy reside with YPFB, the state-owned oil company, and to an extent with ENDE, the state-owned power company. MEH's ability to influence YPFB and overall hydrocarbons policy is greatly constrained by the fiscal dependence of the state on direct revenues from YPFB. This fiscal tie to the state budget has also limited YPFB's ability to plan and manage its investment programs. Other influences on energy policy derive from the regions, whereby regional development corporations (RDCs) use regional tax revenues and hydrocarbon royalties to carry out some activities in the sector, mainly electrification, and, in the Department of Santa Cruz, industrial gas distribution.

[4] The acronym MEH is used throughout the report although with new government (August 1993) it has been changed to National Secretariat of Energy.

The law gives MEH scope in establishing guidelines for energy policy; setting energy prices; and in coordinating, controlling, supervising, and monitoring sector activities.

1.14 In the past, YPFB has been responsible at the national level for producing hydrocarbons, but also for formulating short-, medium-, and long-term plans for the hydrocarbon subsector, although MEH has played a greater role in the last two years. YPFB has a monopoly for supply and distribution up to the ex-refinery point. The state-owned oil company is also responsible for specifying annual plans within the framework of the national budget and has primary responsibility for all activities associated with exploring, developing, refining, industrializing, transporting, and commercializing hydrocarbons. These activities include studies, construction, operation, and administration. Hydrocarbon products are distributed domestically by YPFB and, at the national level, recently by participation of the private sector, in accordance with the Hydrocarbon Law. Overall, the distribution system operates under a cost-plus arrangement.

1.15 MEH has defined the priority objective of the country's hydrocarbon policy as the need to increase the production of liquid fuels. This is necessary both to save foreign exchange by limiting the need for petroleum imports and to assure a reasonable level of government income required to guarantee monetary stability.

1.16 The instruments proposed to achieve this objective are: first, the liberalized commercialization of hydrocarbons in the domestic market (downstream oil and natural gas), and, second, measures that encourage greater exploration and field development to increase the reserves of liquid fuels. The government has taken a number of steps to liberalize natural gas distribution and use. For example, it has drafted a Natural Gas Code regulating private gas distribution and promulgated CNG regulations that authorize the establishment of private CNG stations.

1.17 A key element in encouraging exploration is to increase the market for natural gas. Given that most of the hydrocarbons found in Bolivia are natural gas and that liquids are often associated with natural gas, creating suitable incentives for exploration means providing suitable market outlets for any natural gas discovered. Because Bolivia's domestic market for energy is relatively small, the government's strategy has focused on developing export markets in neighboring countries. Gas has been exported to Argentina since the early 1970s, and, in recent years, the main focus has been on the vast Brazilian market.

Energy Sector Challenges and Opportunities

1.18 The energy sector has not kept pace with the recent structural adjustments in the economy. Competition in the sector is the exception rather than the rule, and government participation remains strong in all phases of energy production, transformation, and distribution. In the short-term, key issues are restructuring of the hydrocarbon subsector and the institutional reform of the energy sector. Delaying decisions on these issues will slow the adjustment program. In the medium-term, issues

that will have to be addressed include reforming the legal framework in the power subsector to allow more competitive private generation, encouraging a more efficient use of energy with minimal environmental impact, and securing efficient supplies of energy for rural areas.

1.19 Steps toward increasing the efficiency of energy operations have been made through the ESMAP-funded National Energy Plan project (1991), which has assisted MEH in designing and implementing an energy data base (updated by MEH staff every three months), training local technical staff, and advising on energy policy guidelines. These guidelines have been issued as a report, "The National Energy Plan," which ENDE and YPFB use as a basis for formulating their investment plans.

1.20 Opportunities for private investment in petroleum exploration and development and greater private participation in all phases of petroleum production have been enhanced by the 1990 Hydrocarbon Law, under which YPFB operates. Yet private production is still modest – about 30 percent of total hydrocarbon output. This is caused, in part, by YPFB's hold on the most potentially productive areas and by the absence of a regulatory and financial environment that would make secondary recovery more attractive to private companies and would provide acceptable and transparent financial terms to interested oil companies.

Subsectoral Issues

Hydrocarbons

1.21 The restructuring of the hydrocarbon sector and consequently of the Hydrocarbon Law and its regulations will assist in addressing the short- and medium-term issues facing this subsector—that is, how to reverse declining oil production and reserves; how to encourage greater private sector participation both upstream and downstream in a more competitive environment; how to diversify and expand the natural gas market; how to restructure or divest YPFB to make it more efficient, autonomous, and accountable; and how to structure an efficient pricing policy for petroleum and natural gas. Even though petroleum prices are above their economic cost, the cost-plus pricing and taxation system for hydrocarbons, established by ministerial resolution, for example, discourages competition and is a function of the financial revenues required for the government's budget. The existing taxation system, in particular, poses one of the most difficult problems for attracting further private participation to the downstream petroleum subsector. YPFB's capacity to finance its exploration and production activities is limited by the state's taxation of its revenues. A fundamental issue is whether scarce public resources should be devoted to production and risky exploration investments, which could be undertaken more efficiently by local and international private sector investors. A key aim of hydrocarbons policy must be to attract the maximum private capital on the most reasonable terms.

Natural Gas

1.22 This subsector will remain vital to the country's economic development. Proven gas reserves are around 800 mmboe, giving a reserves-to-production ratio (R/P) of about 40 years. Natural gas exports to Argentina accounted for 25 percent of total exports until the revision of the contract in May 1992. Lower export prices to Argentina, and possibly lower volumes in the medium-term, create an economic imperative to find alternative markets. The potential opening of the Brazilian market on acceptable terms is thus fundamental to the country's economic future.

Power

1.23 The state-owned power utility, ENDE, is charged with formulating electricity subsector plans, based on the guidelines of the national energy plan. ENDE also designs, constructs, and operates interconnected generation and transmission systems both under its ownership and under concession. Private companies and cooperatives in the electricity subsector are also involved in planning, constructing, and operating electricity generation and distribution facilities and systems; these activities are carried out under the terms of the Electricity Code and the national electrification plan, prepared by ENDE every five years.

1.24 The main drawbacks in the Electricity Code are that it gives no incentives for operating efficiently; costs can be passed on to consumers because power tariffs are not correlated with marginal costs but are based on rate-of-return legislation. Under the current situation, future investments will still be concentrated in ENDE, and the government will continue to bear the associated risks. This situation thwarts efforts to make the power sector self-sustaining (hence, avoiding dependence on the national budget) and to incorporate private capital into the electricity industry.

1.25 In addition, efficiency-related issues concern the structure and level of tariffs perceived by consumers. The gap between power tariffs and marginal costs may lead to a recurrence of government transfers to finance the investment program. Also needing to be addressed are the organization for reaching a least-cost operation of the system; the responsibility for developing the least-cost expansion plan; and the assignment of clear-cut responsibility for the execution of specific projects within the plan. Natural gas accounts for 33 percent of total power generation; thus, there is a close link between improvements in efficiency in the gas subsector and the efficient development of power supplies.

Energy Efficiency and the Environment

1.26 Until now, end-use energy efficiency and the environmental impact of energy-related operations (production, transport, conversion, and use) have received little attention. As energy production and demand increase however, with expected higher levels of economic growth, particularly in the hydrocarbon and power subsector, the

impact of energy production and use on the environment will become increasingly important. In this context, Bolivia's ability to maximize use of its natural gas resources will help to limit the environmental impact of economic growth.

Rural Energy

1.27 In the past, the government's energy policy has focused on urban energy needs. As a result, the rural energy policy is uncoordinated; each institution acts without a coherent strategy, and public and private investment in the expansion of rural energy system are negligible and characterized by a supply-driven orientation.

1.28 The overall result of this institutional situation has been underinvestment in rural energy needs and lack of a demand-driven orientation toward rural energy policies. There are three fundamental reasons for reversing this situation. First, agriculture is the most important sector in Bolivia in terms of contribution to GDP, accounting for about 21 percent of total GDP and 40 percent of total employment. Second, weak energy infrastructure and services in the rural sector are main constraints to private sector investment. Third, under the current supply structure, low-income households are being penalized through higher monthly bills for fuel expenditures for lower-quality fuels. Although natural gas may have a limited role in the rural sector, increased natural gas use in the cities can be important in freeing resources, such as LPG, for rural use.

Overview of the Report

1.29 This report is designed to address in a comprehensive manner the many issues and options faced by Bolivia in the development of its natural gas resources. Each chapter addresses a key area of the natural gas subsector:

- *Chapter 2.* Addresses the issues related to *exploration and production of natural gas* in Bolivia, particularly the outlook for gas discoveries, the problems of past investment in exploration and production, and the policies by which a far greater role can be found for the private sector.
- *Chapter 3.* Looks at Bolivia's *gas transmission system* and some of the issues raised by its management, and future investment plans.
- *Chapter 4.* Discusses the outlook for gas usage in the *industrial, residential, and commercial sectors,* where the efficient management of gas distribution is a key issue.
- *Chapter 5.* Examines the use of gas in the *power sector* which is by far the major consumer of natural gas in Bolivia. The chapter points out that much power sector planning to date has not addressed the close linkage between gas transmission and power generation investment.

- ***Chapter 6.*** Looks at the potential for expanding the use of *compressed natural gas* (CNG) in the transport sector in Bolivia (it has been on a small scale), and recommends a policy for its effective use.
- ***Chapter 7.*** Focuses on Bolivia's gas export potential and examines the rapidly changing nature of the *regional gas market* in the whole Southern Cone of Latin America.
- ***Chapter 8.*** Looks closely at the nature of the *Argentine gas market,* Bolivia's current major outlet for gas, concentrating on the complex demand-supply outlook in this market and its major institutional and regulatory changes.
- ***Chapter 9.*** Examines in detail the *potential market for gas in São Paulo,* Bolivia's major target market for gas exports, and discusses some of the issues raised by plans to export Bolivian gas to that market.
- ***Chapter 10.*** Assesses the prospects for exports of gas from Bolivia to the *North of Chile,* where the large energy demand of the copper industry is sometimes viewed as a potential market in addition to the Brazilian and Argentine markets.
- ***Chapter 11.*** Examines the issues raised by the need to set *prices for natural gas* in Bolivia in accordance with economic efficiency. The implications of setting transport and distribution tariffs for gas in accordance with traditional regulatory principles are also examined.
- ***Chapter 12.*** Focuses on the *institutional and regulatory reforms* needed to implement policies efficiently in the natural gas sector.

2

Exploration and Production in Bolivia

2.1 Bolivia's hydrocarbon reserves are predominantly composed of natural gas. Of the total 1,350 mmboe proven and probable reserves, only 187 mmboe (14 percent) are of liquid hydrocarbons.

2.2 Although most of Bolivia's prospective basins remain to be properly explored, well-explored areas have mostly yielded natural gas. YPFB figures show that natural gas has formed an increasing proportion of total hydrocarbon discoveries over the past few decades, with the share of gas rising from 71 percent in the 1960s to 81 percent in the 1970s and 88 percent in the 1980s. Bolivia is fortunate in that natural gas is generally found in gas-condensate fields with a relatively high liquid content.

2.3 The total proven and probable reserves and the main fields of natural gas in Bolivia are shown in Table 2.1. It can be seen that nearly 50 percent of the proven reserves are located in four fields. Of the total reserves, 75 percent are in fields controlled by YPFB, and the remainder are operated by the private sector.

Table 2.1 Proven and Probable Reserves by Major Field, as of January 1, 1991 (bcf)

Field	*Operator*	*Proven*	*Probable*
Rio Grande	YPFB	710	n.a.
Vuelta Grande	YPFB	542	286
Escondido	Private	388	n.a.
Yapacani	YPFB	338	n.a.
Vibora	YPFB	203	220
Bermejo	Private	194	121
San Alberto	YPFB	41	601
Other	YPFB	188	342
Other	Private	399	341
Subtotal YPFB		**3,023**	**1,449**
Subtotal Private		**981**	**463**
TOTAL		**4,004**	**1,912**

Note: n.a. = no probable reserves are listed.
Source: YPFB.

2.4 These figures are derived from a certification of reserves carried out by two U.S. companies in connection with the export project to Puerto Suarez, as well as from YPFB's own figures. In addition to the figures shown for 1990, discoveries during 1991 are estimated to have raised January 1, 1992, reserves figures to 4,108 bcf proven and 2,334 bcf probable.

2.5 The certification of reserves by the specialist companies resulted in a downgrading of YPFB's estimate of proven reserves by 14 percent for the fields concerned. The companies did not estimate reserves in the fields operated by private contractors or in minor YPFB fields. In general, the downgrading of reserves has been caused by a lack of adequate appraisal and development drilling by YPFB, which led the companies to shift reserves to the probable or possible categories.

2.6 An important issue for Bolivia is the need to maintain a properly certified inventory of natural gas reserves. Appraisal of natural gas discoveries for the sake of determining the size of reserves may not, in itself, be justified where there is no identified market for the gas. Nonetheless, for the purposes of gas marketing, a clear picture of the gas reserves situation is essential. The ability to convince potential consumers of the reliability of future gas supplies is critical in obtaining commitments from consumers. Thus, it is advisable to determine a policy for appraising reserves, both through regular technical studies and through additional drilling when the gain in terms of proven marketable reserves is likely to be large.

Potential for Reserves Additions

2.7 Of Bolivia's total area, approximately 47 percent has proven or possible hydrocarbon potential. Past exploration and development, however, have focused on a small part of the total area. For the purposes of exploration history and future prospectivity, the country can be divided into two distinct zones.

a. ***The traditional zone.*** All the significant hydrocarbon discoveries made so far in Bolivia have been concentrated in a relatively small area of the country: The Southern sector of the sub-Andean sedimentary belt, which extends south from the middle of the county (slightly north of Santa Cruz) in a 200 km wide swath, and in the Chaco region in the extreme southeast of the country. This zone covers 17 percent of the area of potential petroleum interest.

b. ***The future potential zones.*** These comprise the plains areas of the Madre de Dios and Beni in the North, the northern sector of the sub-Andean belt, and the Altiplano. Together, these zones comprise 83 percent of the prospective territory of the country. These areas are generally fairly remote, with jungle cover impeding operations in the North and high-altitude and mountainous terrain representing challenges in the Altiplano.

2.8 As Table 2.2 shows, nearly all of the exploration drilling to date has focused on the traditional zone. This zone accounted for 83 percent of the wells drilled to end-1990, with 2.8 wells/sq. km of prospective area. By comparison, the 17 percent of

wells drilled in the nontraditional zone accounted for only 0.1 wells/sq. km. Hence, the future potential zones have been virtually unexplored to date. Even in the traditional zone, it is worth pointing out that the well density is relatively low. In general, the exploratory effort to date in Bolivia has thus been quite limited.

Table 2.2 Total New Field Wildcat (Exploration) Wells Drilled

Zone	*% of total area*	*No. of wells*	*% of total wells*	*Wells/ sq. km*
Traditional area	15.3	243	83.5	2.8
Nontraditional areas	84.7	50	16.5	0.1

Source: YPFB and mission estimates.

Exploration Policy

Liquids versus Gas Reserves

2.9 A key factor driving Bolivia's exploration policy for hydrocarbons has been the priority given to maintaining reserves of liquids sufficient to prevent substantial imports of petroleum products. Because of the difficulty of finding new liquids reserves in the gas-prone traditional area, Bolivia's liquids production fell from a peak of about 24,000 bpd in 1981 to a low of about 19,000 bpd in 1986. Since then, production has recovered to about 24,000 bpd in 1991. Proven and Probable reserves of liquids stagnated for most of the 1980s, but have risen modestly since 1988 (Table 2.3).

Table 2.3 Crude Oil and Condensate Reserves, Production and Consumption, 1981-1991

Balance Element	*1981*	*1986*	*1990*	*1991*
Reserves (mmbbl)				
Proven	159.6	156.0	179.7	187.4
Probable	n.a.	125.0	119.2	111.1
Production (mbd)	24.3	19.1	22.9	24.4
Consumption (mbd)	21.2	19.9	22.4	23.0
R/P ratio (years)	19.7	19.5	15.7	13.7

Note: Reserve/Production ratio (R/P) is based on proven reserves.
Source: YPFB and mission estimates.

2.10 Demand for petroleum products fell by 12 percent between 1981 and 1985, both because of Bolivia's economic problems and because of the substitution of diesel and fuel oil by natural gas. Since 1985, however, demand has grown by 4 percent per year. This has been caused mainly by demand growth in the transport sector, principally for diesel. Overall, Bolivia has been able to maintain a precarious balance between supply and demand for liquids, with small exports in most years. The reserves-to-production ratio, based on proven reserves, has fallen from 20 in 1986 to 14 in 1991, although when probable reserves are taken into account, it is comfortably above 20.

2.11 With most potential for large-scale gas-for-oil substitution outside transport and households now exhausted (see chapter 4), rising transport demand is likely to keep demand for oil products on an upward trend (except where compressed natural gas is introduced on a large scale; see chapter 6). Hence, there is a continued strong requirement for liquids discoveries to avoid imports.

2.12 A key issue for Bolivia is how to generate investment in exploration, so as to discover liquids, given the gas-prone nature of much of the country's geology. Investment in exploration increases the chances of finding gas reserves, and because of a large surplus of gas relative to available markets, there is no short-term guarantee of gas sales. Private investors in Bolivian exploration will thus strongly discount the value of acreage according to the risk of finding gas of limited immediate apparent value.

2.13 In these circumstances, attracting private sector investment depends first on building market prospects for gas—in particular, through development of export markets (for further discussion see chapter 9). An additional factor to be considered is that export market development itself requires a seliable reserve base, which must be generated through exploration in gas-prone areas.

2.14 Private investors are most likely to be reassured by a policy that aims at two goals simultaneously: (a) credible reassurance of Bolivia securing additional market outlets through exports, and (b) guarantees that they will be able to benefit from gas sales should exports be secured. The former requires a strong and consistent marketing focus within the Bolivian MEH (as discussed in chapter 12), and the latter requires well-articulated terms in exploration contracts relating to natural gas, as discussed below.

2.15 For YPFB, the risk is more of undertaking exploration in gas-prone areas that stand limited chance of yielding sufficient liquids discoveries to justify the investment risk. Because of the high proportion of natural gas discovered, YPFB's finding costs for liquids is relatively high. Reliable figures for YPFB's and contractors' exploration investment are not available over a long period, but available statistics show that during 1981 to 1990, a total of 75.2 mmbbl of liquids were discovered in Bolivia (proven and probable). This finding involved drilling 93 exploratory wells. Although it is difficult to calculate precise finding costs for YPFB, this data suggests that the company's finding costs for liquids are relatively high by international standards. When the oil equivalent of natural gas discoveries are added, however, the finding costs per unit of hydrocarbons drops substantially. This suggests that YPFB should evaluate the economics of exploration wells carefully if these are mainly focused on liquids discoveries and that its overall exploration policy must be integrated with a strategy of giving value to natural gas discovered through undertaking effective marketing.

Roles of YPFB and the Private Sector

2.16 Bolivia's exploration policy has been based on both YPFB and the private sector. About 25 percent of the total prospective area is reserved for YPFB, mainly areas

around the producing fields (in the traditional zone), and some areas strategically located in each one of the main prospective future potential zones.

2.17 Of the remaining 75 percent of the prospective area, about 31 percent is already under contract to foreign companies or under negotiation. Agreements with foreign companies fall into two basic categories: (a) those signed during the 1970s, which resulted in discovered fields that are now generally in production (e.g., Tesoro, Occidental, which was sold to Sol Petroleo in 1991), and (b) those signed more recently, generally involving relatively high risk exploration in the future potential zones.

2.18 For its own area, YPFB developed a detailed 10-year exploration plan in 1990. The plan sets up a number of project units on a regional basis and is designed to appraise fully the potential of the areas under YPFB's control. The plan marks a shift from YPFB's traditional exploration emphasis, which focused on the identification of hydrocarbons in structural or anticlinal traps within the traditional area. Such prospects have now mostly been drilled; hence, the new plan focuses on (a) identifying and drilling stratigraphic-structural or purely stratigraphic traps in the more traditional areas and (b) the drilling of wells in new areas in the future potential zones. It can be expected that the more subtle traps in the traditional zone (sub-Andean and Chaco) will yield further natural gas and condensate fields. The future potential zones show promise, however, of yielding oil discoveries, according to preliminary geochemical and drilling information.

2.19 Overall, YPFB's 10-year program was forecast by YPFB to yield 466 mmbbl of crude oil and condensate and 5.0 tcf of natural gas. The program foresaw a substantial amount of seismic acquisition and other geological and geophysical work and the drilling of 159 exploration and appraisal wells, at a total cost of US$698 million over 10 years. Of this total, about US$155 million would have to come from external financing (essentially multilateral or bilateral credits).

2.20 A key issue is whether the strategy of YPFB solely undertaking risk exploration, within its traditional area and in high-risk areas, is justified. As outlined in chapter 12, a fundamental question for the Bolivian hydrocarbons sector, for natural gas as well as oil, is whether scarce public financing should be devoted to a sector in which there is such good potential for attracting private investment, both foreign and local.[5] There must also be the question of whether YPFB can undertake the technical and project management aspects of exploration as effectively as the private sector. During the 1980s, YPFB's fulfillment of its drilling plans averaged only 53 percent, and YPFB's seismic and other technology lags behind the most modern practices internationally. Finally, it should be noted that the petroleum industry does not usually resort to large-scale debt financing for exploration, as would be the case with YPFB's plan (and has been the case with YPFB in recent years). Exploration is typically financed from cash flow or by raising equity.

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5 The new government wants to end state investment in hydrocarbons by "capitalizing" YPFB.

2.21 To date, YPFB has dominated exploration in Bolivia, accounting for 90 percent of the exploration wells drilled since 1981. However, some companies have begun to explore in Bolivia in recent years. Passage of the Hydrocarbons Law in 1990 introduced some additional legislative certainty regarding investment and improved the tax position of foreign (especially U.S.) investors in relation to home-country taxation.[6] It also provided for association contracts between YPFB and private investors. Because of political and legal uncertainties, no contracts were signed between 1978 and 1985. Since 1985 a dozen contracts have been signed, most of them since 1988. These contracts mark a new phase in Bolivian exploration in that they largely relate to high-risk nontraditional areas. Given the high risk of exploration in these areas, however, companies' commitments are correspondingly modest. Companies can generally withdraw after an initial period of three years, and most companies commit only to geological and geophysical work rather than to drilling. Thus, total spending commitments of the seven contracts signed in 1990 and 1991 is only US$15 million.

2.22 For a country of its potential, and given the remarkable process of economic and political stabilization in recent years, Bolivia has promoted active exploration on a relatively limited basis. For example, the country has not held formal and well-publicized bidding rounds. Although the oil industry is relatively efficient at seeking out opportunities where openings exist, Bolivia should nonetheless increase marketing of its acreage to ensure it maximizes foreign investment on the best terms. With regard to natural gas, a credible marketing strategy and willingness to offer suitable contract terms are vital to this process. A more effective process of promoting private investment in exploration and production would permit the withdrawal of the state from direct investment in this area. Scarce public resources could then be devoted to areas with less potential for attracting private sector investment, including both the social areas and certain basic infrastructure.

Licensing Terms of Natural Gas Exploration and Production

2.23 To provide incentives to private investors to explore for hydrocarbons in Bolivia, the government must offer acceptable reassurance that should natural gas be discovered, there will be a reasonable chance for the contractor to make a return on his investment. This is also essential to ensure that any gas discoveries are efficiently exploited by contractors.

2.24 Any exploration and production contract must contain special provisions for natural gas. This is because, unlike oil, natural gas does not necessarily have a ready market or a well-defined market price. Moreover, the transport of natural gas is both more costly, and less flexible than oil. Production of liquids often involves coproduction of large volumes of gas, the disposal of which must be arranged. Historically, hydrocarbon exploration was mainly based on the anticipation of discovery of liquids, and terms for natural gas were mostly left to be resolved after discovery. Increasingly, however, as

6 A new Hydrocarbon Law is under preparation in 1994.

natural gas markets have developed and exploration has identified many areas as gas-prone, exploration contracts have sought to define the terms for natural gas more fully.

2.25 Within Bolivia, exploration contracts are governed by the Hydrocarbons Law of 1990. This law gives YPFB the right to enter into operation and association contracts with third parties. As regards exploration and production, the law contains few provisions that take account of the special features of natural gas, which is generally covered by provisions common to liquids. More specific references to terms for natural gas are included in the contracts signed with specific companies, and these inevitably differ in their details.

2.26 To attract private capital to explore in Bolivia, both for oil and for natural gas, it is important that contracts establish clear provisions in the following areas:

a. ***Right to natural gas.*** Companies exploring within Bolivia will want to have a clearly established right to natural gas as well as to liquids (historically, some countries have distinguished between the two). Bolivia's provisions in this regard are generally satisfactory.

b. ***Definition of "commerciality" of a gas discovery.*** Unlike an oil discovery (where a market can be presumed), a gas discovery will only be commercial if a suitable market is identified. The decision to declare a discovery "commercial" is important in the petroleum industry, as it often defines a transition point from exploration to production operations, with associated obligations on the contractor. This is a difficult area, but neither the Hydrocarbons Law nor Bolivian contracts appear to identify a suitable procedure for deciding commerciality (this is closely linked to point c below).

c. ***Contract term and timing.*** Because gas can only be produced when a suitable market is available, the length of contracts and the timing of obligations must be more flexible than for oil. In general, to allow markets to be identified, gas clauses should permit the contractor to retain the rights to a gas discovery, without declaring commerciality, for much longer time than for the case of oil. The investor should, of course, be required to make efforts to develop markets during this period. In addition, the prolonged market development holding phase should not erode the production phase, so as to maintain the overall viability of the development. In Bolivia, the law allows a two-year extension to the exploration period when "only natural gas" is discovered and no market exists. This period is too short, given that new markets in Bolivia will come only from prolonged attempts at export sales. The period should be made as long as 10 years (with appropriate review and obligations on the contractor). In addition, the present two-year extension years counts against the maximum contract period (up to 30 years), whereas the production phase should not be reduced owing to the market development delay.

d. ***Gas marketing rights.*** There should be clarity as to whether the contractor has the right to market gas, both to the internal and export markets. In Bolivia, the situation concerning internal marketing is unclear. In theory, YPFB makes the contractor's share of the gas available to the contractor after deducting royalties and taxes in kind. The Hydrocarbons Law provides for private parties as well as YPFB to undertake gas commercialization for the internal market. Contracts make it very difficult, however, for the contractor to dispose of its gas independently of YPFB, given YPFB's control over pipelines. In market terms, the position regarding export markets is more important, and the law gives YPFB a monopoly of gas export sales. YPFB can, however, undertake export sales "with private participation" in the interests of the country subject to MEH approval. There is clearly a need to clarify the situation concerning internal sales further (partly through defining pipeline access; see below). For export sales, the YPFB monopoly reflects a position common in both developing and industrialized countries, given the strategic and political dimension of gas exports. In Bolivia, YPFB's monopoly is not fully regulated by MEH, however. A solution would be to allow contractors to have the right to propose export schemes to MEH (or the gas regulator acting for MEH), which can decide whether YPFB or the contractor should have primary export rights.

e. ***Gas pricing.*** In most developing countries, the absence of market pricing for gas makes the terms for pricing of gas in contracts particularly important. In countries with a gas deficit, pricing on the basis of substitute energy products (such as fuel oil) is relatively straightforward. Where there is a large gas surplus, as in Bolivia, pricing can be much more difficult. (Internal gas pricing issues in Bolivia are considered more fully in chapter 11.) For private investors in Bolivia, the provisions regarding gas export sales prices are, in practice, more important. In this area, best international practice suggests that producers should be entitled to receive a reasonable netback from the export price after allowing for acceptable rates of return on the export infrastructure. It is understood that this is the general practice in Bolivia as regards export sales to Argentina. There is no provision of this kind in the Hydrocarbons Law, however. Moreover, where YPFB remains the monopoly seller of natural gas for export, the transparency of export sales terms and costs is not assured. This could be resolved by strengthening the export sales price provisions, by ensuring regulatory oversight of export sales, and by permitting contractors to export gas themselves, subject to regulatory approval.

f. ***Fiscal terms for gas discoveries.*** The different cost and risk structure of natural gas is sometimes recognized by countries through somewhat better fiscal terms for natural gas than for oil. This also helps to encourage exploration in gas-prone areas. In Bolivia, no special terms for gas are defined in the Hydrocarbons Law. In contracts, gas terms may be different from those for oil, but without any overall pattern. Bolivia's contracts are effectively royalty contracts, with no cost-recovery element. This is generally undesirable for both oil and gas in that the government cannot capture a fair share of the rent from highly profitable contract areas. In

addition, the system discriminates against more marginal developments. This is particularly serious for natural gas because netback values at the wellhead tend to be much lower than for oil. Further, given the absence of cost recovery and other rent-absorption mechanisms, there is a risk that the high potential rent from fields with large amounts of associated gas will not be captured where all the gas can be exported (as may be the case with future sales to Brazil). Addressing this issue will require a thorough review of current fiscal terms for exploration in Bolivia, ensuring that gas receives more appropriate treatment alongside oil and taking account of likely changes in the gas market, should an export scheme materialize.

g. ***Flaring or venting.*** Situations may arise in which the production of liquids is only economic if flaring, or venting, of associated gas is permitted. Such a calculation, of course, does not take into account the detrimental environmental effects with regard to global warming. Moreover, in many cases, the depletion premium attached to the natural gas will not be taken into account (see chapter 11). The Hydrocarbons Law in Bolivia does not mention flaring; hence, YPFB's substantial flaring is apparently unregulated (see below), and provisions are left to individual contracts. In general, these contracts provide for flaring only subject to MEH approval. While some countries have a legal ban on flaring, it is probably better to leave the matter to the discretion of the government—that is, MEH. Bolivia's provisions should be more clearly spelled out as government policy and made applicable to all participants (including YPFB) on the same terms.

h. ***Access to pipelines.*** Investors who may find natural gas need to be reassured of fair access to pipeline infrastructure. In Bolivia, the law provides, in principle, that private companies may build and operate pipelines or sell gas directly to third parties. It does not provide a legal right of third-party open access to excess pipeline capacity however. In general, contracts give producers a right to either participate with YPFB in pipelines, or to build their own. While references may be made in contracts to tariffs to be charged for pipeline use, there is no established fair basis for such tariffs. Bolivia needs to clarify this point through the introduction of appropriate regulated tariffs and through guarantees of open access to YPFB or other operators' pipelines (see chapter 12).

2.27 If producers are to be attracted to explore in Bolivia, where the risk of natural gas discoveries is high, these issues must to be fully clarified. Moreover, it is important from a gas development perspective that policies applicable to different contracts be similar; this will help ensure that gas development is driven by economic rather than by fiscal or contractual considerations. If contract and fiscal terms differ substantially between gas fields, the ranking of field development priorities by contractors (based on their net returns) will differ greatly from the strict economic ranking (based on total returns to both contractor and government). This will reduce the economic benefits of gas development for Bolivia. To this end, Bolivia needs to develop the following linked framework to attract investors:

- ***A model contract.*** This would set out clearly all the basic provisions applying to natural gas (and oil).
- ***A natural gas code.*** This would clarify (and where necessary modify) the gas-related provisions of the Hydrocarbons Law and would establish an effective regulatory agency for gas (see chapter 12).

2.28 Enactment of both of these measures will provide investors with reassurance that they will be able to gain a reasonable advantage from natural gas discoveries, particularly as new export markets are developed. Progress has been made in this respect through development of regulations to the Hydrocarbon Law (with the support of UNDP funds).

Natural Gas Production

2.29 Bolivia's natural gas production is marked by two unusual features: (a) to a large extent, gas production is driven by the desire to extract associated liquids and (b) the volume of production is well in excess of market requirements, leading to substantial reinjection, as well as some flaring.

2.30 Bolivia's basic gas production balance is shown in Table 2.4. It can be seen that only 51 percent of the gas was marketed, mostly for export as well as for the domestic market or as LPG. Most of the remainder was reinjected, or to a lesser extent, flared.

Table 2.4 Natural Gas Balance (mmcfd) 1981-1991

Balance item	*1981*	*1986*	*1987*	*1988*	*1989*	*1990*	*1991*
Production	481	441	442	465	512	510	526
Reinjection	213	165	167	168	185	180	188
Own use	13	17	20	19	22	23	22
Flaring	19	15	15	28	43	41	48
LPG extraction	7	7	8	7	12	13	11
Domestic sales	17	22	27	28	37	41	45
Export sales	212	214	205	216	214	213	211

Source: YPFB.

2.31 The large excess of production over sales is owing to the production of gas for liquids extraction in two forms: (a) in retrograde condensate fields such as Vuelta Grande and Rio Grande, where reinjection is essential to maintain liquids recovery and (b) in fields, such as Vibora and Sirari, where gas is produced in association with liquids. The predominance of the former type of field is shown in Table 2.5, where it can be seen that three condensate fields—Vuelta Grande, Rio Grande, and Porvenir—accounted for 57 percent of production in 1991.

Table 2.5 Natural Gas Production by Major Field (mmcfd) 1981-1991

Field	*1981*	*1986*	*1987*	*1988*	*1989*	*1990*	*1991*
Rio Grande (YPFB)	258	159	140	137	133	123	112
Porvenir (Private)	14	121	121	119	117	106	99
Vuelta Grande (YPFB)	0	21	25	37	71	88	91
Subtotal YPFB	375	269	280	314	352	329	338
Subtotal Private	106	172	162	151	160	181	188
TOTAL	**481**	**441**	**442**	**465**	**512**	**510**	**526**

Source: YPFB.

2.32 By mid-year 1993, contractors accounted for only 26 percent of total natural gas production, but for a higher percentage of domestically marketed and exported gas. The main producers of natural gas are Tesoro, Perez Companc, and Pluspetrol. Currently, Sol Petroleo and Maxus have no gas field in production.

2.33 Bolivia's production is divided into three areas: (a) the North, consisting of the "Boomerang" area, where the major fields are Yapacani, Vibora, Sirari, and Cascabel; (b) the Center, around Santa Cruz, where the major fields are Rio Grande, Santa Cruz, and Naranjillos; and (c) the South, close to the Argentine border, where the major fields are Vuelta Grande, Porvenir, San Alberto, and Bermejo.

2.34 Despite Bolivia's tendency to develop fields for their liquids reserves alone, substantial volumes of gas remain undeveloped. About 60 percent of proven reserves have been fairly comprehensively developed with pipelines to gas plants and main transmission lines. Some 27 percent have been partially developed and lack access to plants or transmission lines, while 13 percent are completely undeveloped.

2.35 Total gas flaring has increased substantially in recent years, as Table 2.4 shows. This has been partly because of the development of fields in the northern area, such as Yapacani, Vibora, Cascabel, and Sirari (total flaring, 29 mmcfd in 1991), for which reinjection and pipeline facilities have been lacking. Nonetheless, flaring is also widespread in other parts of Bolivia, such as at the San Roque field in the South (4 mmcfd), or the La Pena field in the Center (2 mmcfd). Overall, flaring reflects the priority given to liquids production over conservation of natural gas.

2.36 YPFB's investment plans for production over the next few years are focused on the northern area. Additional drilling is planned in the Vibora, Yapacani, and Sirari fields, as well as in the recently discovered Carrasco field. This latter field marks a substantial additional discovery (0.3 tcf of proven reserves with the first well), confirming the remaining potential of the northern area. Various scenarios of production increase have been postulated for these fields, ranging from about 110 mmcfd up to 200 mmcfd by 2000, with up to 15,000 bpd of liquids. A key issue is the need to link these fields to the main reinjection and LPG extraction facilities at Rio Grande. To this end, a pipeline of 160 mmcfd capacity is planned (see chapter 3). The main aim is to make gas available for

export to Brazil from Rio Grande; however, pending export outlets, large scale reinjection facilities will be required.

2.37 In the South, the major development effort is focusing on the Bermejo field, where production is being built up by Pluspetrol to about 20 mmcfd. A pipeline from Bermejo to the Ramos field in Argentina will create an alternative for Bolivian exports to Argentina, reducing the draw on the main fields along the line to Yacuiba. The San Alberto field represents a major development opportunity (probable reserves are at least 0.6 tcf), but the relatively low liquids content of the field means that it will have to await gas market opportunities before being developed.

2.38 The key issue arising in gas production is the need for better overall planning and coordination of projects. It is unclear whether YPFB has a well-focused production strategy, which would take account of the often-conflicting need of extracting liquids while preserving gas. The continued large-scale flaring in many fields is evidence of a lack of coordinated planning of liquids recovery and gas handling. YPFB's reservoir modeling capability is also short of international standards. YPFB's economic analysis of projects is also inadequate; for example, the value of liquids production is counted at local market prices (which include a substantial government tax markup) rather than at international prices. Political pressures on YPFB to maximize short-term liquids production, even at the cost of flaring rich gas, add to the problem. It is also unclear whether YPFB takes proper account of the need to integrate the private sector fields into its overall planning. Currently, YPFB's control over exports allow it to channel development requirements to its own fields, rather than buying from the most convenient source. Matters are further complicated by the inadequate fiscal regime, which gathers rent more comprehensively from YPFB fields than from contractors' fields, hence helping to discourage purchases from contractors.

2.39 To improve on this situation, action needs to be taken on several fronts: (a) YPFB's own planning capacity needs to be improved so that production strategy and project ranking are more thorough; (b) YPFB should open all its fields to private sector participation using appropriate contracts (for example, the existing association terms) so as to overcome shortages of capital and inadequate technical and economic analysis that can lead to inefficient development; and (c) market transparency should be developed for gas, with equal treatment for fields, in the private and public sectors, that will give an incentive to market-driven efficiency in gas development.

3

Natural Gas Transmission System in Bolivia

3.1 Bolivia has a well-developed natural gas transmission system. Because gas now reaches all significant potential usage centers, the investment required for incremental capacity and the effective management of the system are issues of concern.

3.2 Natural gas is supplied to customers in the cities of Santa Cruz, Cochabamba, Oruro, La Paz, Sucre, Potosi, Tarija, and all other minor centers by the YABOG Pipeline Company and by YPFB. Gas is also exported to Argentina by the YABOG Pipeline Company. In 1993 an agreement was signed between YPFB and Petrobras and between the Bolivian and Brazilian governments regarding future gas sales to Brazil. The characteristics of these systems are described below, and key issues are identified.

The YABOG Pipeline Company

Overview

3.3 The YABOG Pipeline Company gathers gas from YPFB and a number of private gas producers throughout Bolivia and then delivers it to YPFB's transmission system at Taquiperenda, which is then supplied directly to local markets in Santa Cruz, Tarija, El Puente, Guabira, and Mineros and also exported to Argentina. YABOG's main 24-in. diameter trunk line runs south 441 km from Colpa to Yacuiba. A 4-in. diameter lateral pipeline runs west 263 km from La Vertiente to Tarija and El Puente, and a 64 km, 4- and 6-in. diameter lateral pipeline runs north from Colpa to Guabira and Mineros. YABOG also operates a number of lateral gas receipt pipelines, the longest of which is a 91 km, 12-in. diameter pipeline from the Campo Tita gas field.

History

3.4 In the early 1960s, the Gulf Oil Company discovered large quantities of natural gas at Colpa and Caranda in northern Bolivia. After favorable discussion with Argentina, Gulf and YPFB formed the YABOG Pipeline Company in 1968, as an equally owned joint venture to export natural gas to Argentina. In 1969 a contract with Argentina

was signed for the purchase of Bolivian gas, and construction was started on the YABOG gas transmission system, consisting of a 441 km, 24-in. diameter pipeline without gas compression. This pipeline was intended to move gas from fields in the Santa Cruz area to the Argentina border. Construction of the YABOG pipeline was halted in 1969 when the government of Bolivia nationalized Gulf Oil's operations in Bolivia. Following a settlement between Gulf Oil and the Bolivian government, construction activities resumed in September 1971, and gas deliveries to Argentina commenced on May 1, 1972.

3.5 Based on a 20-year contract, initial deliveries to Argentina were 140 mmcfd. In 1976 gas deliveries were expanded to 210 mmcfd, and in 1979 deliveries were further expanded to 230 mmcfd. In 1980 two compressor stations were added along YABOG's main trunk pipeline, one at Saipuru and another at Caigua, in anticipation of additional gas deliveries.

3.6 Since YABOG's export pipeline was placed in service in 1972, major gas deposits have been discovered in southern Bolivia at Vuelta Grande, La Vertiente, Porvenir, and Bermejo. The connection of these resources has greatly increased YABOG's capability to deliver gas to Argentina. Though Bolivia currently delivers only 215 mmcfd of gas to Argentina, YABOG's pipeline system is capable of delivering up to 380 mmcfd (including deliveries directly from Bermejo into the Argentine pipeline section, south of the border).

3.7 Since its original construction, the YABOG pipeline system has been expanded to service local markets in Bolivia. YABOG supplies gas to customers in Santa Cruz and operates local gas transmission pipelines between Villamontes and El Puente in the Tarija Department (263 km, 4-in. diameter pipeline) and between Colpa and Mineros, North of Santa Cruz (64 km, 4- and 6-in. diameter pipelines). YABOG also supplies gas to the YPFB pipeline system at Taquiperenda. The company operates a number of lateral gas receipt pipelines and an independent gas export pipeline that moves a small volume of gas to Argentina from the Bermejo field by means of a 4 km, 12-in. diameter pipeline system.

System Operation

3.8 YABOG's gas dispatch center is located in Santa Cruz. Gas flows and pressures are reported to the dispatch center by radio on an hourly basis by YABOG's operations staff, by YPFB's production groups, and by private producers, including Sol Petroleo (at Porvenir), Tesoro (La Vertiente), Pluspetrol (Bermejo), and Perez Companc (Colpa and Carandan). Based on hourly gas flow data received by the gas dispatch center, producers are instructed to increase or decrease gas deliveries as appropriate. Generally, flows in the system are balanced by varying the gas input from the YPFB-operated Rio Grande gas field, owing to the contract arrangements with the private gas producers and the ease with which the output of the Rio Grande field can be varied. Operation of the YABOG system is relatively uncomplicated because the gas flow through the system is

nearly constant (except for flows in the small-diameter delivery laterals). YABOG's total annual maintenance cost was about US$750,000 in 1991. This represents about 0.7 percent of the capital cost of the system, which is about the same as would be expected for a similar system in North America. In 20 years of operation, YABOG has experienced one pipeline failure, caused by metal fatigue in a weld. The failure occurred in February of 1988 and was immediately repaired.

Gas Quality

3.9 The export contract with Argentina specifies that gas delivered to Argentina will contain between 4.15 and 6 percent butane and propane, which Argentina removes from the gas stream in a turbo-expander plant in Campo Duran. Because butane and propane have high value, to minimize the amount of butane and propane leaving Bolivia, YABOG controls the quality of the gas delivered to Argentina to the lower end of the specified allowable range.

Expansion Plan

3.10 Over the next five years, YABOG plans the following projects:

- ***Rio Grande to Santa Cruz pipeline.*** Rich gas containing significant quantities of butane and propane is now supplied to consumers in Santa Cruz directly from YABOG's main trunk pipeline. To allow the butane and propane to be recovered in the Rio Grande gas plant, a 46 km, 12-in. diameter pipeline will be built to move lean gas from the Rio Grande gas plant to Santa Cruz; this will be done to replace the rich gas now taken from the trunk line. No new infrastructure is required at the Rio Grande gas plant because the existing gas processing and storage facilities have adequate capacity to support the project.
- ***Connection of northern gas fields to existing facilities at Colpa.*** A 110 km, 16-in. diameter pipeline is planned to bring 160 mmcfd of gas from Bolivia's Yapacani gas field to YABOG's existing gas pipeline at Colpa. As part of the project, a 29 km, 8-in. diameter pipeline will also be constructed to bring gas from the Vibora field to Yapacani. Construction was scheduled to start in 1992.

3.11 Future projects are expected to include the following:

a. ***An expansion of the Rio Grande gas plant.*** The existing plant is based on a gas absorption process and has a capacity of 190 mmcfd. The planned expansion consists of the addition of a 120 mmcfd turbo-expander plant.

b. ***The installation of refrigeration plants at the Yapacani and Vibora gas field.*** This would allow more efficient recovery of butane and propane.

YPFB Pipeline System

Overview

3.12 YPFB provides natural gas to Cochabamba, Oruro, La Paz, Sucre, and Potosi. YPFB's pipeline system receives gas both from the gas plant at Rio Grande and from YABOG pipeline system at Taquiperenda. From Rio Grande, gas moves 456 km west in a 10-in. pipeline through Oconi and Huaynacota to Parotani. At Huaynacota, a 6-in. pipeline moves gas a short distance into Cochabamba. From Parotani, a second 6-in. pipeline moves gas a further 252 km west through Oruro and Senkata into La Paz. From the YABOG pipeline at Taquiperenda, a 1-in. pipeline moves gas west 104 km, where it narrows to 8-in. in diameter before continuing a further 14 km to a compressor station at Cerrillos. From Cerrillos, gas continues to move west through a 39 km, 8-in. pipeline loop and a parallel 141 km, 6-in. main pipeline to a compressor station at Torre Pampa. From Torre Pampa gas continues to flow west, where it moves through a 16 km, 8-in. diameter pipeline loop and an 87 km, 6-in. diameter, main pipeline to Tarabuco. At Tarabuco the gas steam splits. A 42 km, 6-in. pipeline moves gas west from Tarabuco to a compressor station at Sucre, and from Sucre a 4-in. pipeline takes gas 114 km further west to Potosi. Also, from Tarabuco, a second 6-in. pipeline moves gas north 22 km to a compressor station at Tapirani. From Tapirani a 6-in., 250 km pipeline moves gas north to Huaynacota (where it is commingled with gas coming from Rio Grande) to supply Cochabamba, Oruro, Senkata, and La Paz.

History

3.13 In 1974 a gas pipeline was constructed from Cerrillos to Sucre to supply a thermal power plant, a cement plant, and a small refinery at Sucre. The expansion of this system followed in 1983 owing to a need to provide energy for the refinery and other industrial users in Cochabamba, for a smelting plant and other industrial users in Oruro, and for industrial users in La Paz. To make sufficient gas available to supply users in Cochabamba, Oruro, and La Paz, a new pipeline was constructed in 1983 to supplement the gas supply from Cerrillos with gas from the YABOG pipeline system. An existing 6-in. diameter oil transmission pipeline (originally constructed in the 1960s) was converted to move gas from Cerrillos to Cochabamba, and from Cochabamba to Oruro and La Paz. In 1984 a 4-in. pipeline was built from Sucre to Potosi to provide gas to mineral recovery plants (not working at present), a small thermal power plant and several small industrial users. In 1987 the 10-in. diameter Altiplano pipeline (GDA) was constructed between the Rio Grande Gas Plant and Parotani to meet expanding gas demand from customers in Cochabamba, Oruro, and La Paz that could no longer be satisfied by the small existing pipeline network.

System Operation

3.14 The system is operated by three district operating groups. The eastern district headquarters, based in Santa Cruz, is responsible for the control of the gas pipeline between Rio Grande and Parotani. The northern district headquarters, located in Cochabamba, controls the gas line between Huaynacota and Cochabamba, between Parotani and La Paz, and between Tapirani and Cochabamba. The southern district, based in Sucre, controls the gas pipeline from Taquiperenda to the outlet of the Tapirani compressor station and from Tarabuco to Potosi.

3.15 Gas flow and pressure information is collected hourly in each district headquarters and is reported daily to the northern district in Cochabamba. The northern district is responsible for central gas dispatch and for system planning activities for the entire YPFB system. Communications are provided by a VHF radio system belonging to YPFB.

3.16 With the exception of the compressor station at Sucre (Qhora Qhora), YPFB's compressor stations are not presently operated. Some of the stations have had units removed and relocated to other parts of the country for service in gas field compression and reinjection applications. A considerable amount of rehabilitation work will be required to return the stations to normal operation. At the Sucre station, one compressor unit is run on an intermittent basis to pressurize the pipeline between Sucre and Potosi, making line pack available to ENDE, thus ensuring adequate gas delivery capability during peak generating periods.

3.17 The load factor on the YPFB pipeline system is dictated by the following load characteristics. ENDE's gas consumption varies with the daily power demand. Industrial consumption is high Monday through Friday and drops significantly on Saturday and Sunday, when most of the plants are shut down. The majority of industrial customers operate on a 24-hr basis, thus daily fluctuations in gas demand are mainly the result of fluctuation in the electrical demand serviced by ENDE. The overall gas demand is approximately uniform from month to month throughout the year. Currently, there is no significant residential gas consumption on the YPFB pipeline system, but residential gas distribution is planned. Local distribution companies have been set up in Cochabamba (Emcogas), Sucre (Emdigas), Santa Cruz (Sergas), and Tarija (Emtagas). YPFB will distribute gas to residential customers in La Paz until a private firm comes forward.

Pipeline Integrity

3.18 The majority of the YPFB pipeline system is laid on the surface of the ground though a program exists to bury the entire pipeline system over time. The system has experienced a number of failures since its installation. Slope stability failures are experienced in the rainy season, and above-ground pipelines are sometimes damaged by falling rocks. Above-ground pipelines are also subject to failure from abrasion caused by movement of the pipelines against the rocky ground surface as the pipelines expand in the

sun during the daytime and contract at night as the temperature falls. Flash-flooding also caused failure of a section of the Altiplano pipeline. Sabotage is another significant cause of pipeline failures on YPFB's gas transmission system. The pipeline from Omro to La Paz has been sabotaged a number of times in the past two years.

Expansion Plans

3.19 YPFB is currently planning the following expansion projects:

a ***Pipe replacement Parotani to Oruro.*** A new 8-in. diameter gas pipeline is being built between Parotani and Oruro. This will increase the gas transmission capacity to Oruro and La Paz and allow the existing 6-in. diameter pipeline to be converted to a products pipeline that would expand products capacity between Cochabamba and Oruro.

b. ***Pipe replacement Oruro to La Paz.*** A new 6-in. pipeline will be built between Oruro and La Paz. The existing 6-in. line will then be converted to a products pipeline to expand capacity between Oruro and La Paz. Construction was scheduled to begin mid-1992.

c. ***Compression stations between Rio Grande and Parotani.*** Two new compressor stations are planned between Rio Grande and Parotani. One station is to be built near Oconi (210 km west to Rio Grande), and a second station at Parotani. Planned compressor station inlet and outlet pressures are 650 and 1,400 psi, respectively.

d. ***Pipeline loop between Tarabuco and Sucre.*** A 12 km, 6-in. diameter, pipeline loop is planned to expand capacity between Tarabuco and Sucre.

Natural Gas Transmission Issues

3.20 In addition to the technical issues mentioned above, the key sector issues in natural gas transmission concern the institutional organization of this activity. The current division between the YABOG and YPFB organizations is not conducive to optimal system planning and operation. The diverse characteristics of the two organizations also lead to a lack of coherence—that is, YABOG is dedicated to running a large export pipeline and YPFB's small but complex gas transmission system is essentially mixed with oil pipelines. The creation of a single company to handle all gas transmission would clearly be beneficial. (For further discussion, see chapter 12.)

3.21 YPFB would benefit from an experienced pipeline consultant in planning the expansion of their pipeline network. The expansion alternatives described above do not appear to represent the most efficient and cost-effective way to expand the capacity of the pipeline network. In addition, it is understood that YPFB sizes its pipelines based on expected average annual gas-flow requirements. Transmission pipelines should be designed to service peak-day load requirements. A gas demand study is required to evaluate customer load factors and to calculate the peak-day gas demand in each demand

center. Using the peak-day gas demand that is determined by such a study, the optimum transmission system expansion program can then be determined.

3.22 It is important that YPFB's transmission planning is closely integrated with demand developments (particularly ENDE's plans) and with gas resource development. Clear market-related interfaces between the gas consumers and producers and the pipeline operators should be established. This may be accomplished by assigning dedicated gas purchasing and marketing staff to groups of consumers and producers, by using gas transportation contracts, and by allowing the transmission company to plan its investments and operations. Also vital is the development of an economically rational tariff structure and regulation, as described in chapter 11.

4

Industrial, Residential, and Commercial Sectors

Current Pattern of Use

4.1 The first cities to use gas in Bolivia were Santa Cruz and Sucre. Following the expansion of the domestic gas grid, Tarija was connected in 1981, La Paz and Cochabamba in 1984, and Oruro in 1989. Although Santa Cruz dominates gas consumption (52 percent of domestic consumption), the extension of the network led to a tripling of domestic consumption over the previous decade from 13.2 mmcfd in 1980 to 40.7 mmcfd in 1991; this increase represents an 11 percent annual growth rate.

4.2 Natural gas is now almost entirely used for power generation and in the industrial sector, accounting for 57 percent and 43 percent of demand, respectively. Fewer than 200 households of the grid are supplied with gas, mostly in Santa Cruz. Currently, gas is supplied to seven of the nine capitals of the Department, and to several minor cities mainly located in the Department of Tarija, in southern Bolivia. From a geographic point of view, the domestic gas grid can be now considered completed because the 11 cities that are already connected represent 95 percent of the urban population and nearly the total energy needs of the industrial sector. Although plans exist to supply the remote city of Trinidad, the capital of the Department of Beni in the northern lowlands, the limited potential consumption makes the construction of a 400 km-long gas pipeline from the Santa Cruz Basin unlikely in the foreseeable future.

Consumption Pattern in the Industrial Sector

4.3 In the first half of the 1980s, Bolivia faced its worst economic crisis of this century. The industrial sector suffered an annual negative growth rate (-5.6 percent), and the situation of the mining sector had an even more negative annual growth rate (-10.6 percent). In 1985 the industrial and mining sectors represented only 18.6 percent of GDP, down from 25.6 percent in 1980. Although neither sector had returned by 1990 to its 1980 level, the strong economic policy put in place from 1986 has enabled both sectors to recover.

4.4 Natural gas consumption in the industrial sector amounted to 16.3 mmcfd in 1991. Although the use of natural gas has developed only recently on a large scale, it now represents 42 percent of the sector's total energy consumption. The balance is met by biomass (32 percent), liquid fuels (15 percent), and electricity (11 percent). Biomass consists mainly of sugar cane residues (bagasse) used in the sugar plants near Santa Cruz. Liquid fuels consist of motor fuels, fuel oil, kerosene, as well as limited quantities of LPG. Motor fuels are used for vehicles in the industrial sector (gasoline and diesel oil) and are not likely to be replaced by natural gas (although a limited amount of diesel oil is used for thermal applications). Considering that for both technical and economic reasons, natural gas cannot easily substitute for electricity and biomass, the remaining potential market amounts to around 35,000 tons per year equivalent to 3.8 mmcfd of natural gas.[7] This figure does not include the mining facilities that are usually located far from the main gas grid. Should the mining sector be included, the potential market would increase by a mere 3,000 tons of fuel oil. According to YPFB estimates, at the country level, the ratio between the current gas consumption and the actual potential market is 58 percent. It would be significantly higher if factories were operated close to their nominal capacity.[8]

Table 4.1 Fuel Consumption in the Industrial Sector, 1989

Fuel oil	24,102	tons
Kerosene	7,039	tons
LPG	2,642	tons
Diesel oil	15,241	tons
Gasoline	7,916	tons
Natural gas	161,114	mcm (15.6 mmcfd)

Source: YPFB.

4.5 No market survey has been conducted recently in the industrial sector; however, based on the figures found in Table 4.1, it is estimated that natural gas has already captured 80 percent of its likely market. With regard to fuel oil, the consumption in both the industrial and the mining sectors was only 27,800 tons in 1991, that is, 17 percent of natural gas consumption. The projections established by the national energy plan for the year 2000 show that fuel oil consumption would remain constant in the industrial sector at about 16,000 tons per year, while consumption would continue to decrease in the mining and metallurgical sector to about 8,000 tons by the turn of the century. All the major potential consumers (namely the cement and glass factories) have now shifted to natural gas, with the exception (1992) of the Empresa Metalurgica Vento in Oruro, for which the substitution of natural gas for fuel oil was decided in early 1992. Following this conversion, the subsequent increase in natural gas consumption will mostly come from the natural growth of the economy.

7 This figure includes fuel oil (25,000 tons), kerosene (7,000 tons), and LPG (3,000 tons).

8 The ratio of 58 percent is the result of both the penetration factor (see paragraph 4.5) and the current low utilization factor of the plants.

4.6 Gas consumption forecasts have been based on reviewed YPFB estimates. Projections were made at the level of each of the seven cities currently supplied with gas. Sustained growth is considered, leading to the improvement of the currently depressed utilization factor of the industrial facilities, mainly in the metallurgical sector. After the recent conversion of E.M. Vento in Oruro, it is assumed that the two (currently shut down) large smelting plants in Potosi will resume activity. Based on this, the annual growth rate would slightly exceed 10 percent in the short term, and then stabilize at annual rates ranging between 5 and 6 percent by the turn of the century. Gas consumption is expected to reach 249 mmcm (24.1 mmcfd) in 1995, 360 mmcm (34.8 mmcfd) in 2000, and 609 mmcm (58.9 mmcfd) in 2010 (Table 4.2).

Table 4.2 Natural Gas Consumption Forecasts in the Industrial Sector, 1991-2010 (mmcmy)

Sector	*1991*	*1995*	*2000*	*2005*	*2010*
La Paz	52.1	59.7	76.4	111.7	153.0
Oruro	5.2	41.0	77.9	81.8	87.3
Cochabamba	34.1	43.3	58.2	78.3	105.3
Potosi	1.8	6.3	11.9	17.5	23.5
Sucre	27.9	37.1	48.5	60.0	84.1
Santa Cruz	40.3	51.1	68.8	92.5	124.4
Tarija	7.2	11.0	18.4	24.0	31.4
TOTAL	**168.6**	**249.3**	**360.1**	**465.8**	**609.0**

Source: Mission estimates.

4.7 Because of its intrinsic qualities and low price, compared with competing energies (including fuel oil), natural gas has reached a significant share of its potential market in a relatively short time. Short-term efforts should now be directed toward the improvement of the global efficiency of gas distribution to the industrial sector:

a. ***Adjustment of gas equipment and materials to the real needs of the customers.*** The size and technical characteristics of the service line that connects the main grid to each customer is not accurately established by YPFB. The diameter of the service line is selected on the basis of the likely peak demand of gas appliances as stated by the future customer. No technical survey has been conducted by YPFB to check the real current and expected peak hour demand of the gas appliances and thus optimize the gas equipment to be installed.

b. ***Improvement of gas appliance efficiency.*** YPFB's Gas Division lacks both human and technical resources that would enable them to be more than a mere gas supplier. Although the Gas Division is part of the Commercial Department, gas activity has been supply-oriented with limited attention paid to the customers. As all major gas utilities have already done throughout the world, YPFB and the private-public utilities operating in this area should now embark on a more customer-oriented policy, and take appropriate measures that would enable them to better know their customers and adjust gas supply to the real needs of the

customers. Each gas distributor should establish a small team of highly knowledgeable technicians, whose mission would be to (a) conduct a technical audit and survey of the appliances to be converted, prior to conversion; (b) propose to, and discuss with, the customer appropriate gas technologies that are likely to optimize fuel consumption; (c) conduct similar surveys at the already converted plants in order to enhance current gas consumption efficiency; and (d) perform the technical evaluation mentioned in paragraph (a) above.

c. ***Set up an appropriate tariff policy***. Current tariff policy is based on a flat price per thousand cubic feet. Although YPFB's Gas Division has tried twice to propose a more appropriate, although imperfect, two-tier tariff structure, such a policy has faced strong opposition from some gas customers. A new tariff policy should be studied and implemented to adjust both the level and the structure of the tariff(s) to the real economic cost of delivering gas to the industrial customers. To this effect, anticipation of real current and expected peak hour demand of gas appliances is a prerequisite to establish a two-part tariff (see chapter 11).

Natural Gas Consumption Forecasts

4.8 Residential and commercial distribution of natural gas was examined in detail in the ESMAP report "Bolivia: Natural Gas Distribution—Economics and Regulation" (February 1992).

4.9 The natural gas consumption forecasts are summarized below.

Table 4.3 Natural Gas Consumption Forecasts in the Industrial, Residential, Commercial, and CNG Sectors, 1991-2010 (mmcmy)

Sector	*1991*	*1995*	*2000*	*2005*	*2010*
Industry	168.6	249.3	360.1	465.8	609.0
Residential and commercial	0.0	54.0	148.7	187.4	225.1
CNG	0.0	1.3	80.8	184.0	184.0
TOTAL	**168.6**	**304.6**	**589.6**	**837.2**	**1,018.1**

Note: CNG represents potential demand (for further discussion, see chapter 6).
Source: Mission estimates.

5

The Power Sector

Background

5.1 The power sector is the major consumer of natural gas in Bolivia, and natural gas represents the major option for power generation in much of the country. Developments in the natural gas and power sectors are thus closely linked. The Bolivian power sector is regulated by MEH through its electricity directorate Dirección Nacional de Electricidad (Bolivia) (DINE). The operating functions are divided among two main companies--Empresa Nacional de Electricidad (Bolivia) (ENDE) and Compaña Boliviana de Energia Electrica (Bolivia) (COBEE). ENDE is a state-owned generation and transmission utility that sells bulk energy, although it serves some final consumers directly. ENDE's shareholders are MEH (80 percent), YPFB (20 percent), and in a very small proportion, Corporación Minera Boliviana (Bolivia) (COMIBOL). Currently, ENDE generates 55 percent of Bolivia's electrical energy and is responsible for overall planning of the power sector.

5.2 COBEE is a private generation and distribution company, owned partially by the U.S. corporation, Bolivian Power Co. Ltd. It has operated in Bolivia since 1925, and generates exclusively through hydropower plants. Whereas ENDE operates both in the central interconnected system—Sistema Interconectado Nacional (SIN)—and isolated areas, COBEE operates only in SIN.

5.3 Several distribution companies, owned by ENDE, COMIBOL or cooperatives, also operate within SIN. The most important noninterconnected companies are SETAR and COSERELEC, state-owned companies that serve the regions of Tarija and Trinidad, respectively. SIN is structured along a North-South axis from La Paz to Potosi and along a West-East axis from Oruro to Santa Cruz.

5.4 As of January 1992, installed capacity in the country was 673 MW, of which 309 MW were hydro and 364 MW thermal. A breakdown of this capacity is shown in Table 5.1. SIN has a total capacity of 543 MW (285 MW hydro and 258 MW thermal, mainly gas turbine units). Generally speaking, SIN is characterized by a balanced distribution of generating facilities, located near load centers, and by relatively weak

transmission links. Although generating facilities include some old hydro and thermal plants, their availability and overall technical performance is satisfactory.

Table 5.1 Installed Power Generation Capacity 1992 (MW)

Company	*Hydro*	*Thermal*	*Total*
ENDE	134	252	386
COBEE	142	0	142
Other utilities	9	28	37
Nonutilities	24	84	108
TOTAL	**309**	**364**	**673**

Source: ENDE.

Current Pattern of Gas Use

5.5 In 1991 hydro generation accounted for 67 percent of total power generation, revealing a higher utilization factor of hydropower plants compared with thermal plants. In the main grid (SIN), which accounts for 88 percent of total generation, hydro generation has priority to dispatch. Thermal plant operation is constrained to periods of hydro supply shortage, that is, mainly to dry seasons and peak hours. In SIN, thermal generation is almost entirely (99 percent) gas-fueled. In 1991 gas consumption for power generation totaled 24.9 mmcfd in ENDE's gas turbine plants, for an energy generation of 694 GWh. This consumption was distributed as follows: 78 percent in Santa Cruz, 16 percent in Cochabamba, 5 percent in Potosi, and 1 percent in Chuquisaca (Sucre). However, Cochabamba's consumption was expected to increase to 25 percent of the total in 1992, when the Valle Hermoso gas turbine installations (4 x 20 MW) were scheduled to be completed.

5.6 Generally speaking, short-term hydrothermal generation decisions are economically rational because the variable costs of hydro generation are much lower than those of thermal plants. In the longer term, the development of the hydrothermal capacity mix has been justified on the grounds that it was more appropriate to install low investment gas turbines instead of dams for seasonal regulation or new hydropower plants for demand portions of lower load factor (that is, during dry seasons and peak loads) and for regions where low-cost gas is available (such as Santa Cruz). This hydrothermal capacity balance has been reached in an environment in which gas prices do not reflect economic costs, however. Therefore, it can be argued that the power-generating mix may not be optimal.

5.7 Gas is supplied for power generation by YPFB under long-term contracts for each power project. These contracts between YPFB and ENDE have the following main characteristics:

- YPFB guarantees to make available specified daily and 4-hour peak volumes. It is specified that the heat content of gas supplied should meet specified technical standards.
- Gas prices are set by the ministry of energy on a volume basis and are adjusted for variations with heat content. A minimum monthly consumption, equivalent to about 5-days, is usually charged. In past agreements, this last condition has not been enforced, however.
- The most recent contract, signed in December 1990 for the gas supply of Cochabamba's gas turbines, does not establish any penalties to YPFB in case it should fail to supply the agreed-on gas volumes.
- Contracts have a validity from 10 to 20 years. It is expected that future contracts will have a 20-year duration.

5.8 Although the agreements indicate a minimum consumption volume, which in the past has not been enforced, the current price system does not provide the correct economic signal to ENDE because, in some regions, gas supply costs are characterized by a relatively high fixed-installation cost that is not captured by the minimum volume charge. Conversely, actual variable gas supply costs are lower than the price charged for each volume consumed. This price system may result in an undercharging for gas for low plant utilization factors, thus creating the following distortions:

- In the short run, that is, for energy dispatch decisions, the higher variable cost may discourage gas consumption when compared to other fuels for power generation. This distortion, however, should have a minor impact on the optimal use of gas because the two main generating options in SIN are gas-fueled thermal and hydro. Because variable hydro costs are always expected to remain below gas supply costs, the hydro-gas dispatch is not affected. Therefore, the impact of this distortion is, constrained to the operation of ENDE's dual fuel plants (Chuquisaca and Villamontes).
- In the long run, the lower average price of gas (compared with gas supply costs) paid by ENDE for low plant factors may create a more serious distortion. The lack of an adequate gas-fixed charge is clearly creating an incentive for overinvesting in new gas turbine plants, particularly for peak- or medium-load operation or in locations where gas transport costs are high and tend to reduce peak-designed hydro plants to less than optimal scale.

Power Demand Projections and Supply Options

Demand Projections

5.9 In 1991 electrical energy final consumption in SIN was as follows:

Table 5.2 Electrical Energy Demand by Consumer Group, 1991

Consumer group	*GWh*	*%*
Mining	208.0	12.1
Industry	417.0	24.2
Residential	707.2	41.1
General	267.7	15.5
Public lighting	61.6	3.6
Other	60.3	3.5
TOTAL	**1,721.8**	**100.0**

Source: ENDE.

5.10 Demand forecasts prepared for the National Electrification Plan considered annual growth of power demand to be 6.3 percent for the period 1987-2010.[9] This average, however, conceals important differences between regions and periods of time. While power demand in the Oriental region (Santa Cruz) was expected to grow at a higher rate (9 percent) than the national average, overall demand was expected to grow faster during an initial period (7.4 percent for 1987-90), and then decline to 6 percent. Comparing actual with forecast values for the period 1987-90, it is evident that (a) overall demand grew at a lower rate, 6.5 percent instead of 7.4 percent, and (b) this decline is solely attributed to a much lower growth in the Oriental region, while in the North-South axis demand grew at a rate higher than forecast. These differences are now attributed to an optimistic perception of Santa Cruz's potential for economic development.

5.11 ENDE is now reviewing and updating Bolivia's power demand projections. Preliminary results provide similar values to those forecast by the above-mentioned 1989 study and are shown in the following table:

9 ENDE; Plan Nacional de Electrificación, October 1989.

Table 5.3 Power Demand Projection for Sistema Interconectado Nacional, 1991-2010

Year	*GWh*
1991	2,018
1995	2,814
2000	3,696
2010	6,329
Growth rates	*%*
1991-1995	8.7
1995-2000	5.6
1991-2010	6.2

Source: ENDE.

5.12 The most important features of the new forecast are the following:

- SIN power demand is expected to grow at an average rate of 6.2 percent for the period 1991-2010. This rate is quite similar to that foreseen in 1989; however, it considers lower loads for the Oriental region.
- The forecast is based on an informal approach that considers two elements (a) power demand growth associated with natural growth trends, such as income and demographic growth, plus the gradual expansion of electricity services and (b) the incorporation and development of new major industrial or mining loads. This approach may be subject to some degree of double-counting, particularly for early years in cases in which more detailed information on new major loads is available. For this reason, the short-term forecast (8.7 percent for 1991-1995) appears somewhat optimistic and inconsistent with Bolivia's economic growth prospects. ENDE's planning staff argues that the high growth foreseen, however, is justified by firm commitments of private and public groups in major investment projects.
- There is great uncertainty about the power demand of the mining sector, which is currently being restructured and liberalized.

Supply Options

5.13 The main energy resources for power supply are hydro and natural gas. Other energy resources, such as biomass and geothermal and diesel oil are important only on a smaller scale for the expansion of isolated systems. Power supply options for SIN are thus constrained to two distinct technologies—hydropower plants and gas-fueled thermal plants.

5.14 Bolivia's hydropower potential amounts to 18,000 MW, of which about 2 percent is now being utilized. Although a great part of this potential consists of mega projects located in the eastern slope of the Andes, there are several attractive medium-size projects near the north or central regions. Two main competing projects are San Jose (127 MW) and Misicuni (120 MW), which could be commissioned by the end of the decade. Owing to market and financial constraints, however, the construction of only one of these projects would be viable during this period. In addition, a set of smaller projects (most of them to be built by COBEE) could add up to 70 MW to the system before 1995.

5.15 Thermal generation options are a function of the type of technology and location. The two most promising gas-fueled thermal technologies required for the expansion of SIN are gas turbines (for an effective capacity range of 25 to 50 MW) and combined-cycle plants. A third option could be the conversion of existing gas turbines to combined cycle. The two main locations for thermal generation are Santa Cruz, closer to the gas fields and at lower altitude, and Cochabamba. Most probably, the least-cost expansion solution for the Oriental (Santa Cruz) region will continue to be the development of gas-fueled thermal plants. In Cochabamba, which is more properly integrated to SIN, thermal plants compete with hydrogeneration, the optimal solution being a well-defined hydrothermal balance. In this case, thermal plants are less attractive because they face higher gas supply costs plus the effects of altitude, which reduces their output, thus increasing effective capacity costs. The correct economic signals concerning fixed and variable costs of gas supply are particularly crucial to expansion plans in Cochabamba.

ENDE's Expansion Plans

5.16 In 1989 ENDE, in cooperation with ENEL, formulated an expansion plan.[10] This plan relied heavily on new thermal plants (open-cycle gas turbines) that were to be installed in Santa Cruz, Cochabamba, Sucre, and Potosi. This expansion would add up to 860 MW during the period 1990-2009, while hydropower expansion would add up to 298 MW during the same period. The implementation of this program would imply a growth in total gas consumption for power generation from 24.9 mmcfd in 1991 to about 90 mmcfd by the end of the planning horizon. According to this plan, most of the gas (between 70 to 80 percent) would be consumed in Santa Cruz.

5.17 A review of the assumptions and methodology of the 1989 plan suggests the need to reassess ENDE's power expansion plan for the following reasons:

- The plan considered an opportunity cost of gas of US$1.00/mcf in Santa Cruz and a marginal transport cost of US$0.10/mcf for existing pipelines, both expressed as variable costs. Owing to very low gas cost in Santa Cruz, this assumption may not create any distortion in generation choices in this area; however, the situation may

[10] This report was prepared prior to the November 1992 revision of ENDE's Least-Cost Expansion Plan.

be quite different for other regions. Incremental transport costs, above existing capacity, were also modeled as variable costs with overall gas cost of US$1.60, US$2.40, and US$2.80/mcf for Cochabamba, Oruro, and La Paz, respectively. Gas transport investments should be considered fixed costs. The use of a variable cost for the above-mentioned locations does not properly reflect the economic structure of transport costs and may create serious distortions because in this particular system (where thermal generation competes with hydro), thermal plants tend to operate at low plant factors, thus resulting in higher average gas costs. Accordingly, with these assumptions, the cost minimization analysis would tend to favor thermal generation as the optimal choice because thermal capacity costs are underestimated.

- A comparison of actual to forecast power loads reveals that the eastern (Santa Cruz) region has been growing at a much lower rate than planned. This would certainly reduce the thermal capacity requirements in Santa Cruz. Conversely, more capacity would be needed in the north and central regions. These changes in the power market may justify bringing forward implementation of the first important hydropower projects from the year 2003 to 1998-1999, thus reducing gas consumption.
- The introduction of a more efficient combined-cycle technology, when economically justified, may also limit gas consumption in power generation.

5.18 The following section analyzes the impact of adopting gas costs on the basis of economic principles and explores the sensitivity of gas consumption to the opportunity cost of gas.

Impact of Gas Costs on the Power Expansion Plan

5.19 Mission estimates for total gas consumption in power generation, based on ENDE's 1989 plan and adjusted for the 1991 power demand projections, are presented in Table 5.4.[11] These estimates, resulting from ENDE's planning methodology, including the above-mentioned gas costs, indicate that gas consumption in SIN would grow from 24.9 mmcfd in 1992 to 65 mmcfd in the year 2000, reaching a peak of 100 mmcfd in 2008. Gas requirements for power may change, however, if gas costs are to reflect real economic costs. The likelihood of any change in gas consumption is investigated in the following paragraphs.

[11] Estimate based on ENDE's hydro 3 scenario plus 1991 actual data, adjusted for 1991 power demand projection, and using the following additional assumptions: (a) 96 percent of total thermal generation is gas fueled, (b) thermal effective capacity for 1990 is 160 MW, and (c) plant retirements refer to thermal plants only.

Table 5.4 Projected Demand for Gas in Power Generation, 1991-2009

Year	*Energy demand (GWh)*	*Thermal generation (GWh)*	*Thermal plant factor (%)*	*Total gas demand (mmcfd)*
1991	2,018	728	41.6	24.9
1995	2,814	1,131	39.7	38.7
2000	3,696	1,896	44.4	64.8
2005	4,818	2,330	38.4	79.7
2009	5,989	2,674	34.2	91.4

Source: ENDE and mission estimates.

5.20 The present section considers levels and structures of gas costs, taking into account economic costs for the commodity and its transport. This is done for the following two main scenarios (see chapter 11):

- ***Low-cost scenario.*** An average economic cost at the wellhead of US$0.50/mcf.
- ***High-cost scenario.*** An opportunity cost of gas of US$1.25/mcf, corresponding to an increasing exports scenario.

5.21 Gas transport costs for Bolivia were estimated following an average incremental cost approach, considering the transport investment requirements for meeting future gas demands in different regions plus operation costs (see chapter 11). These costs expressed as fixed demand charges and usage charges are presented in Table 5.5.[12]

Table 5.5 Gas Transport Costs, Fixed Demand and Average Usage, 1991-2003

Delivery zone	*Monthly demand charges ($/mcf of peak day capacity)* 1991	2003	*Average uses charges ($/mcf of actual consumption)*
Santa Cruz	3.69	3.31	0.0073
Tarija	36.77	24.82	0.0868
Cochabamba	13.47	13.77	0.0355
Oruro	16.70	17.37	0.0452
La Paz	21.38	11.40	0.0592
Sucre/Potosi	11.04	11.40	0.0277

Source: Mission estimate.

[12] Gas transport costs are below those shown for estimated delivery zone transport in Table 11.2. The variance is explained by the fact that the gas transport costs exclude depreciation of the current pipeline system and only take account of incremental costs. This is standard practice when dealing with power investment planning.

5.22 Considering peak-day operation plant factors for gas turbines and combined-cycle plants of 66 percent and 75 percent, respectively, and appropriate thermal efficiencies, these transport costs translate to gas costs for power generation in Santa Cruz and Cochabamba as shown in Table 5.6.

Table 5.6 Gas Costs for Power Generation

Location	*Gas fixed costs ($/kW month)*	*Gas variable costs ($/mcf)*	
		Low cost	*High cost* [a]
Santa Cruz			
Gas turbines	0.70	0.51	1.26
Cochabamba			
Gas turbines	2.52	0.54	1.29
Combined cycle	1.84	0.54	1.29

Source: Mission estimates.

[a] Variable costs include usage transport cost, as given in Table 5.5, plus the cost of gas, that is, US$0.50/mcf for the low cost scenario and US$1.25/mcf for the high-cost scenario.

5.23 The lower fixed costs for combined-cycle plants is explained by the fact that owing to its higher efficiency, these plants require less fuel for each unit of capacity supplied. These costs can be used within a least-cost planning methodology to assess more accurately the true relative costs of gas and hydro plants.

5.24 The composite cost of gas (that is, the average cost per mcf, including both fixed and variable costs, for a utilization factor of 57 percent or 5,000 hours of operation per year) resulting from the above estimates varies for the low- and high-cost scenario from US$0.70 to US$1.45/mcf for Santa Cruz and from US$1.38 to US$2.13/mcf for Cochabamba.

5.25 A comparison of the average, fixed, and variable costs of gas presented above with current gas prices indicates the following:

- Although the two-part tariff for gas costs more accurately reflects economic costs and thus provides the correct signal for an optimal operation and expansion of the power system, it is unlikely that it would have any significant impact on short-term energy dispatch decisions. This is explained by the fact that gas variable costs (although lower than those considered by ENDE) will always be higher than hydro variable costs.
- In the long-term, the impact of adopting appropriate cost-based gas prices would be a function of the cost scenario. For a low gas cost (US$0.50/mcf), gas consumption in power would tend to remain the same as estimated in Table 5.4, or even increase provided that thermal plants would be operating at a relatively high utilization factor. For a high gas cost (US$1.25/mcf), gas-fueled generation in Santa Cruz would tend to remain the same since at US$1.45/mcf, gas turbine

plants would still be the least-cost solution, even when transmission costs are added. In Cochabamba and other locations, however, composite gas costs of US$2.13/mcf or higher would tend to reduce thermal power investments. (Cochabamba's gas cost would increase to US$2.50/mcf for a perhaps more realistic utilization factor of 40 percent, whereas in La Paz it may exceed US$3.25/mcf). Furthermore, the application of a two-part pricing system would practically eliminate all investments in gas-turbine power plants outside Santa Cruz, unless a high utilization factor is clearly guaranteed. It should be noted, however, that even in the scenario in which no additional gas-fueled plants would be added to the system in locations other than Santa Cruz, total gas consumption for power generation would be reduced by only 10 percent. In fact, estimates indicate consumption levels for this scenario as illustrated in Table 5.7.

Table 5.7 Total versus Santa Cruz Gas Demand for Power 1991-2005 (mmcfd)

Year	*Current forecast*	*Thermal expansion in Santa Cruz only*
1991	24.9	24.9
1995	38.7	34.5
2000	64.8	54.9
2005	79.7	72.1

Note: Current forecast is based on ENDE's 1989 plan.
Source: ENDE and mission estimates.

- Although at the national level the reduction in gas consumption may not be significant, in the long run the drastic reduction of gas demand for power in Cochabamba, or higher regions, would entail important savings in gas transport investments to YPFB. It should be noted, however, that there could be a corresponding increase in ENDE's capital costs, although total public sector investment may be lower.
- Gas-fueled combined-cycle plants would not be competitive in Santa Cruz, when compared to open-cycle gas turbines, because low gas costs do not justify additional investments in increasing thermal efficiency. Furthermore, combined-cycle plants would only be marginally competitive in Cochabamba for the high gas-cost scenario. Project-to-project comparisons indicate that, in this location, a combined-cycle plant would only be competitive at gas prices about or above US$2.35/mcf, which compares with a gas cost range of US$2.13 to US$2.50/mcf for the high cost scenario.

Recommendations

5.26 The following key actions should be taken to ensure the efficient interaction of investment policies for power and natural gas:

- To reflect real economic costs, gas purchase agreements between ENDE and YPFB should be based on a two-part gas price system along the lines presented in this report (chapter 11). A price system that clearly separates fixed transport costs from variable costs would eliminate existing distortions, thus improving gas consumption decisions in power and allowing consistency between YPFB and ENDE's investment programs. Thi. approach should be combined with better-designed and enforceable gas sales contracts.
- The power-planning process should also be based on a two-part gas cost system, both in formulating a least-cost expansion plan as well as in designing specific power plants. This adjustment would tend to eliminate unjustified thermal peak-load plants in regions in which gas transport costs are high. Moreover, it would lead to a refined design for future hydro plants that would enhance their peak capabilities.

6

Compressed Natural Gas

6.1 The use of natural gas as a transport fuel to substitute for gasoline and diesel represents a potentially important new market for gas in Bolivia. An analysis of the vehicle fleet in Bolivia has established that about 34,000 vehicles could be converted to compressed natural gas (CNG) fueling. These vehicles currently consume about 50 percent of the gasoline used in Bolivia and are located primarily in the cities of La Paz, Cochabamba, and Santa Cruz. A total of about 70 CNG refueling stations would be required. Those vehicles that would be the prime candidates for conversion to CNG fueling are micro- or omnibuses, taxis, and trucks with driving patterns restricted almost exclusively to their home cities. Very few, if any, diesel-fueled vehicles would be candidates for conversion to CNG fueling within current fuel-price conditions. Given appropriate commercial conditions, an automotive CNG market in Bolivia could achieve its full potential within a period of about 10 years. At market saturation, about 17.5 mmcfd (180 mmcmy) of natural gas would be consumed annually as CNG; this figure corresponds to the displacement of about 200 million liters (140,000 tons) of gasoline, or 50 percent of current consumption. Use of CNG would thus contribute substantially to relieving any future pressures on Bolivia's self-sufficiency in the production of liquids.

6.2 The commercial prospects for development of CNG industry in Bolivia appear to be good. The government has been in favor of the project since its prefeasibility study (funded by the World Bank) in 1987. This study established both the technical and economic viability of CNG use for transport in Bolivia. There has been limited progress since that time, however. This section thus intends to review the current status of CNG development within the overall context of a natural gas utilization strategy, to identify the reasons why industry development has not proceeded, and to recommend actions required to overcome current impediments.

6.3 A reexamination of the national benefit economics of a project for the nationwide introduction of CNG as an automotive fuel indicates that the project would be highly attractive. For a 15-year project life and employing reasonable assumptions on cost and market development, an internal rate of return of up to 61 percent could be achieved. This corresponds to a net present value (NPV) for the project of US$84 million, using a 12 percent discount rate.

6.4 Consideration of high and low CNG-industry growth scenarios shows that high national benefit returns would still be achieved, even if industry growth were to proceed at a much slower rate than that anticipated. The project would have a net annual inflow of foreign funds of between US$25 and US$60 million at maturity, depending on the financing configuration employed. The netback value attributable to natural gas at the CNG station would be US$5.80/mcf, which is attractive in comparison with the economic cost of gas.

6.5 It has been recognized by government and private sector interests that the development of a CNG industry in Bolivia would be beneficial. To date, however, industry growth has not proceeded for the following reasons:[13]

- There is no established pricing structure for CNG.
- There is no regulatory framework for establishing and operating CNG refueling stations and CNG vehicles.
- The market risk associated with investment in CNG operations is perceived to be too great (largely owing to the absence of pricing and regulatory frameworks).
- Financing arrangements have yet to be established.

6.6 Several moves either have been or are being made toward overcoming the impediments to CNG industry growth. Thus, MEH is currently developing standards and regulations for the commercial use of CNG and is considering a number of pricing policy options. YPFB, which is likely in the future to limit its involvement in the natural gas market to supplying gas to the city gate, has developed two projects designed to demonstrate the use of CNG as a transport fuel, although these are now unlikely to proceed. On the commercial side, a number of private sector groups have developed plans and projects to install and operate CNG-refueling stations and to convert vehicles to CNG use. Several of these projects have reached the point whereby arrangements have been made with equipment suppliers, vehicle fleet operators, and external financing sources; thus, investment could proceed quite shortly.[14]

6.7 It is thus apparent that the CNG industry in Bolivia can be developed by the private sector, which is currently poised to proceed. This would be in keeping with the government's strategy of withdrawing the public sector from areas that can be viably commercialized. To overcome the current impediments to CNG industry growth, the government will need to do the following:

- Develop and promulgate an appropriate CNG pricing policy together with providing government assurances of its sustainability

[13] This paragraph does not take into account of a recent set of MEH regulations (December 1992) that deals with CNG-related questions.

[14] At the time of publication of this report, CNG has been introduced on a small scale in a few towns in Bolivia.

- Develop and issue a regulatory framework for CNG industry development to be supported by appropriate standards for the use of CNG
- Develop a quality assurance program to include both personnel training and inspection and certification of components as a means of maintaining consumer confidence in CNG
- Develop and implement a well-formulated and appropriately targeted marketing program for the promotion of CNG
- Establish financing requirements for CNG development.

Pricing

6.8 A proposed CNG pricing policy has been developed based on the assumptions that all participants in the CNG industry must be offered sufficient incentive to ensure their involvement and must achieve a sufficient financial return on their investment. These requirements have been identified as follows:

- Vehicle owners will require the cost of conversion to CNG to be recouped out of savings within 18 months. This translates to a maximum CNG-to-gasoline energy equivalent retail price ratio of 0.75. The ratio need not, however, be less than 0.65.
- Investments in CNG refueling stations will require an internal rate of return in the order of 40 percent during the initial stages of industry development when the market risk is high. As the market grows and the risk is reduced to more manageable proportions, an internal rate of return of about 20 percent is considered appropriate. Ideally, station operators would like to have a guaranteed differential between the purchase price of natural gas and the sales price of CNG, although this is not considered necessary.
- Local gas distribution companies that represent natural monopolies need to achieve a reasonable rate of return on investment (which may be in the range of 13 to 15 percent).
- The CNG pricing policy developed should not financially disadvantage YPFB.
- There should be no net loss in fiscal revenue to the government as a result of CNG industry establishment.
- The pricing policy should reflect the possible need to subsidize vehicle conversions during the early stages of implementation of the CNG development project.

6.9 Based on these considerations, the following pricing policy has been developed:

- The retail price of CNG should be regulated at between 0.65 and 0.75 of the energy-equivalent price of gasoline.

- CNG refueling stations should be required to pay a licensing fee, based on their natural gas throughput. For the first 2 years of the development program, this fee should be zero, increasing to US cents 3.2/liter-equivalent from Years 2 to 5 and, to US cents 4.2/liter-equivalent in Years 5 to 10.
- A levy of 1.8 cents/liter should be applied to the price of diesel staring from the onset of the CNG implementation program and maintained for a period of 10 years.
- The price of natural ;as to CNG stations should be maintained at the levels applicable to industry (currently US$2.00/mcf).
- All CNG industry operations should be subject to normal taxes and duties.
- The government should guarantee the CNG-to-gasoline price relativity, the price of natural gas, and stage-wise increase in license fees throughout the 10-year CNG implementation period.

6.10 Such a pricing policy would result in the pricing structure illustrated in Table 6.1. It will be noted that the proposed imposition of a small, constant levy on diesel has the combined effects of helping rationalize transport fuel price relativities (because diesel is currently underpriced relative to gasoline) and providing additional fiscal revenue after Year 5 of CNG industry development.

Table 6.1 Proposed Pricing Structure (1992 US$)

		Year		
Item	*Unit*	*0-2*	*3-5*	*6-10*
Gasoline retail price	cents/liter	44.0	44.0	44.0
Diesel retail price	cents/liter	36.8	36.8	36.8
Add CNG levy	cents/liter	1.8	1.8	1.8
Diesel base price	cents/liter	35.0	35.0	35.0
CNG retail price	cents/liter eq	34.2	34.2	34.2
Station margin	cents/liter eq	1.8	1.8	1.8
License fee	cents/liter eq	0	3.2	4.2
VAT and transport tax	cents/liter eq	1.3	1.3	1.3
Natural gas price	US$/mcf	2.00	2.00	2.00
Gas distribution cost	US$/mcf	0.70	0.70	0.70
City gate price	US$/mcf	1.30	1.30	1.30

Source: Mission estimates.

Regulations

6.11 Drafts of proposed CNG industry regulations and their supporting standards have been reviewed by consultants, and several modifications have been suggested to facilitate the removal of real and potential impediments to industry growth. The proposed standards will require, however, detailed technical review before they are issued. The assignment of institutional responsibilities should also be more fully considered.

Quality Assurance

6.12 Because of the high market risk involved and the adverse financial consequences that would result from a loss in consumer confidence in CNG, it is essential that an effective quality assurance program be developed and implemented as an integral part of CNG development. The experience of other countries in applying and administering quality assurance procedures in the CNG industry should be used as the basis for developing such a program in Bolivia.

Marketing

6.13 Effective marketing will be required for CNG industry development, and an appropriate marketing strategy needs to be developed. Primary responsibility for promoting CNG should lie with the private sector, with CNG refueling stations acting as a key focal point for such promotion. YPFB and the local gas distribution companies should also participate in CNG marketing, insofar as they have a vested interest in increasing the sale of natural gas.

6.14 During the early stages of CNG implementation, it is likely that vehicle conversion costs may need to be subsidized to promote market development. Such subsidies will be considered the prerogative of the private sector, with CNG refueling station operators having the greatest incentive to offer such subsidies. It is important that the return to the CNG refueling station investor should be sufficient during these early years to enable the provision of subsidies, if required.

Finance

6.15 Contrary to expectations, the acquisition of finance for CNG industry development is not considered to be a major problem. Thus, it appears that several potential private sector investors have already assembled investment groups that include some foreign participation and have structured financing packages to cover the supply of equipment. It thus seems probable that suitable finance will be forthcoming—provided that the Bolivian government can create an attractive investment environment for CNG development as discussed herein.

6.16 To summarize, a number of actions can usefully be taken to ensure that CNG industry development takes place in Bolivia:

- The government of Bolivia should promote CNG industry development as a matter of policy and should create the necessary commercial environment to allow CNG to be introduced and sustained by private sector companies.
- The government should establish a pricing policy for CNG such as that proposed herein. Its further development or modification, if required, should be based on similar analyses to those presented (including the tariff analysis described in chapter 11).
- The proposed CNG industry regulations and supporting standards should be submitted to external review, finalized, and promulgated as soon as possible.
- A quality assurance program with associated regulatory and administrative framework should be developed immediately. It should be based on experience in forming and applying similar programs in other countries.
- A strategy and plan for CNG market promotion should be developed and implemented. Marketing should be the primary responsibility of the private sector but should be coordinated with, and supported by, YPFB and local gas distribution companies.
- An industry coordinating body should be established to coordinate and administer activities of mutual interest. A similar centralized body may be required within government to be responsible for the institutional administration of the CNG industry.

7

Regional Gas Trade Overview

Background

7.1 The Southern Cone region of Latin America is a region in which there may be considerable potential for the development of regional gas trade. The region comprises Bolivia, Argentina, Chile, Uruguay, and Paraguay; for the purposes of this analysis, it also includes the central and southern areas of Peru and Brazil.

7.2 Within this region, only Bolivia and Argentina have well-developed domestic natural gas markets. Gas reserves, however, are more widely spread, although in both Chile and Peru, the reserves are too remote from markets to be easily developed at present. Overall, Argentina dominates the region in terms of the size of its gas reserves and market. Bolivia's reserves are much smaller, but its limited domestic market gives it an in-built surplus for export. Moreover, it is well-positioned geographically to take advantage of regional demand growth.

7.3 Four major basins contain most of the gas reserves in the region. The two gas-rich basins closest to areas of demand, and therefore the most developed, are the basins in southern Bolivia and Northwestern Argentina, and the Neuquen basin in Argentina. The two more remote regions are the Austral (or Magallanes) basin in Argentina and Chile at the extreme south of the continent (which has been partially developed), and the Madre de Dios basin in southern Peru and northwest Bolivia, which contains the giant Camisea field (which is not yet developed).

7.4 The region has considerable growth potential for natural gas consumption. In the developed markets of Bolivia and Argentina, a likely acceleration of economic growth will continue to drive demand upward, even though gas for oil substitution is already well-advanced. In addition, there is great potential for the incorporation of new markets based on gas imports, especially in Brazil, Chile, and Uruguay. In all of these countries, much of the long-term potential market is in power generation, because gas in combined-cycle plants can provide an attractive option in comparison with hydro schemes that are plagued by increasing costs and environmental disadvantages.

7.5 A further important trend in the region is the liberalization of the natural gas industry. This is being led by Argentina, which has privatized the state gas monopoly. In general, to varying degrees, other countries are also loosening the state's domination of the industry and envisage a much greater role for private sector investment in future gas projects. When combined with the widespread move toward more economic pricing of petroleum products and other energy sources, this creates an environment in which market signals are likely to play an increasing role in shaping gas projects.

7.6 Nonetheless, liberalization of the gas industry can also create uncertainty in the implementation of large gas projects. These projects require strong technical and project management skills, which historically has been provided mainly by the state oil and gas companies of the region. With the move away from domination of the industry by these companies, there is a danger of a transitional vacuum of project leadership, while new private sector participants acquire the confidence and capability to lead projects. Coupled with this is the legal and regulatory uncertainty surrounding international projects, as well as the difficulty of financing large projects in an environment of continuing regional economic uncertainty and debt problems.

Gas Trade Projects

7.7 Within the region, a number of gas trade projects are in various stages of consideration (some of these projects are discussed in more detail in the next chapters):

- ***Bolivia - São Paulo.*** This project involves selling gas from Bolivia directly to the São Paulo market, and to other markets in southern Brazil. A gas sales agreement has been signed, subject to satisfactory financing of the pipeline. The current planned volume is up to 16 mmcmd (565 mmcfd), but the market could probably absorb much larger quantities in the longer term (see chapter 9).
- ***Bolivia - Brazil.*** This project involved the export of gas-based electricity to Brazil. This would have required 3 mmcmd (106 mmcfd) of gas to be transported 580 km from Santa Cruz to Puerto Suarez on the Bolivian side of the Bolivia - Brazil border. The gas would have been used in a 500 MW power plant, with the electricity sold to a Brazilian utility. This project has now been put on hold in light of plans to export gas to São Paulo.
- ***Argentina - Brazil.*** Several proposed schemes to sell gas directly from Argentina to Brazil include an alternative to the sale of Bolivian gas to São Paulo, by taking gas directly from the northwest basin in Argentina to São Paulo, either across Paraguay or south of Paraguay. Another possibility would be to tie in to the Argentine pipeline system closer to Buenos Aires, with the initial aim of supplying southern Brazil. The former scheme has been the subject of general proposals from Argentina to Brazil, but Brazil favors the route from Bolivia.
- ***Argentina - Chile.*** The governments of Chile and Argentina have agreed to allow a project to proceed to take gas from Argentina to central Chile through private initiatives. The Argentine government would permit exports up to a level of 5

mmcmd (177 mmcfd), although demand may take up to 10 years to reach this level. There are plans to take gas from the Neuquen basin in Argentina across the Andes to Chile, mainly to the Santiago area.

- ***Bolivia - Chile.*** There is a general proposal to develop a pipeline from the gas fields of Bolivia to northern Chile, where the copper industry and power generation have a large requirement for energy. While the overall energy market in northern Chile may be relatively large, it is now served by low cost coal from Magallanes (southern Chile), which may be difficult to displace (see chapter 10).
- ***Argentina - Uruguay.*** The governments of Argentina and Uruguay have agreed to permit a project to take gas from Argentina to Uruguay. As with the project in Chile, the intention is that this should be done by the private sector. The market in Uruguay is relatively small, lying mainly in Montevideo and probably totaling no more than 2 to 3 mmcmd (71 to 106 mmcfd) by 2005.

Scenarios for Future Developments

7.8 Despite its potential for gas demand growth, the region lacks the proven reserves base on which to build a major expansion of the market. In part, this must be attributed to past underinvestment in natural gas exploration and development. Two factors have been behind this problem: (a) the lack of perceived attractive markets, owing to the small size of local demand (for example, in Bolivia), or the obligation to sell to a state company at an unattractive price (for example, in Argentina); and (b) the tendency by state companies to reserve much of the best acreage for themselves, despite their lack of financial resources to invest in exploration. The high debt burden of many of these countries, and their past inconsistency in handling foreign investment, has also dissuaded international petroleum companies from investing in exploration if the risk of finding gas were high. It is generally accepted that, over the region as a whole, there are substantial additional gas resources to be discovered. Nevertheless, there have been few systematic attempts to examine this potential.

7.9 Within this overall context, the key issue in the Cono Sur market is how to create additional incentives for exploration, so as to generate the reserves to allow the gas market to develop further. The exploration activity that would generate reserves is likely to be driven by market signals, the availability of pipelines to markets, the presence of reliable buyers, and acceptable prices for gas. Within the Cono Sur, the greatest transformation in market opportunities and prices is likely to be achieved through linking existing reserves to the São Paulo market. As Table 7.1 shows, this market has by far the greatest potential impact on overall demand.

Table 7.1 Gas Markets, Existing and Potential, in Cono Sur, 1991-2005 (mmcmd)

Markets	*1991*	*2005*
Existing[a]		
Argentina	52.5	80.3
Bolivia	1.3	4.9
New (import markets)		
Brazil	n.a.	15-30
Chile	n.a.	4-8
Uruguay	n.a.	2-3

[a] Excludes small Brazil/Chile use of domestic gas.
Source: Mission estimates.

Table 7.2 Status of Proven and Probable Gas Reserves in Cono Sur, 1991 (bcm)

Reserves	*Proven*	*Probable*
Argentina	537	48-215
Bolivia	116	66
Chile	115	n.a.
Peru	300	

Source: Mission estimates.

7.10 Thus, we can envisage three different generic scenarios for the development of the Cono Sur market by 2005, each representing a different pace of development of overall demand. It should be emphasized that these scenarios have as much to do with the timing of market development, as with its scope. The key question is how dynamic the Cono Sur market will be over the next 10 to 15 years.

7.11 The three possible scenarios are outlined below, with supply-demand figures shown in Table 7.3.

- ***Low.*** In this scenario, only the existing markets continue to develop, and the overall gas market stagnates. New schemes to export gas essentially are postponed until after 2005, mainly owing to institutional failures to reach agreement on project structure and to a difficulty in financing projects that may be viewed as risky by private investors. As Table 7.3 shows, in this case, existing proven and probable reserves are fairly adequate to support the market, implying that prices will not rise substantially to bring forth additional investment in exploration and production.
- ***Mid.*** In this scenario, limited new development takes place, but this stops short of a very large expansion of trade, including only basic export schemes. Bolivian gas is exported to São Paulo at the levels currently planned, and Argentine gas is

exported to Chile and Uruguay. However, the market stops short of very rapid takeoff, in part because of limited use of gas for power outside Bolivia and Argentina. Nonetheless, as Table 7.3 shows, this scenario will require substantial new gas discoveries and considerable new investment in the industry.

- ***High.*** This scenario would see larger exports between the countries, with the key addition of a scheme to export gas from Argentina to Southern Brazil. It would represent a rapid transition from the Mid case, which would come about in the mid 1990s, to a higher level of demand. Exports from Bolivia to Brazil are higher than in the Base case, as are those from Argentina to Chile owing to use of gas for power generation in combined cycle plants. As Table 7.3 shows, this scenario would require very large new reserve additions within the region.

Cono Sur Gas - Three Scenarios to 2005

Low	No new markets—limited new investment to 2000 • No Brazil and Chile imports by 2005
Mid	Limited new markets—moderate new investment to 2000 • Brazil imports 16 mmcmd (565 mmcfd), Chile imports 3 mmcmd (106 mmcfd) in 2005
High	Large new markets—major new investment to 2000 • Brazil/Uruguay import 32 mmcmd (1,130 mmcfd), Chile imports 3 mmcmd (106 mmcfd) in 2005

Table 7.3 Reserve Requirement for Market Development Scenarios in Cono Sur, by 2005 (Bcm)

	Current reserves	*Production 1991-2005*	*15 yr. R/P 2005*	*Surplus (deficit)*
Low	700	275	465	(70)
Mid	880[a]	460	600	(180)
High	880[a]	495	700	(315)

[a] Includes Chile but excludes Peru.
Source: Mission estimates.

7.12 The key distinction is between the low scenario, which essentially sees a nondynamic market, and the other two, with varying degrees of dynamism. In essence, the distinction between the mid and the high case must rest on the capacity of the region to generate sufficient reserves in response to the initial stimulus provided by the São Paulo market. Given the uncertainty over the ultimate reserve potential of the region, this can only be resolved by allowing exploration investment to be undertaken.

7.13 In all of the scenarios, a certain sequence of reserve development is likely to occur. In essence, this is based on the division of reserves in the region between those closer to the markets and those that are more remote. Because additional reserves deliveries can only be made through new pipeline capacity, in general, the farther

reserves are from the markets, the higher their cost of delivery. Table 7.4 shows the reserves by basin, and their distance from Buenos Aires and São Paulo, respectively. It can be seen that the reserves of the Neuquen Basin are particularly well-placed for the Buenos Aires market, while those of Bolivia and northwestern Argentina are well placed for both São Paulo and Buenos Aires. The reserves of the Austral basin in Argentina and Chile are poorly placed, as are those of the Camisea field in Peru.

7.14 As the Cono Sur market grows, it is thus likely that incremental reserves will come initially from the Neuquen basin for the Argentine market and from Bolivia and northwest Argentina for São Paulo. In the longer run, as reserves in these basins begin to be fully committed, new supplies will have to come from the Austral basins, and possibly from Camisea.

7.15 The development of gas prices under the scenarios will depend on the success of future exploration, and in particular on the location of new discoveries. If large new discoveries are made in the basins close to the markets (Neuquen and Southern Bolivia/Northern Argentina), then prices in the major markets (Buenos Aires and São Paulo) will be kept down by the modest cost of incremental deliveries. However, a failure to find sufficient new supplies in the lower cost basins would create a tightening of markets in the major consumption centers. The higher prices, which this would bring about, would be sufficient to call forth new capacity at higher cost from the more remote basins (Austral, Camisea), which would create a higher long-term price level.

Table 7.4 Distances from Basins to Major Gas Markets (km)

	Markets	
Basin	*Buenos Aires*	*São Paulo*
Southern Bolivia/Northwestern Argentina	1,400	1,800
Neuquen	1,000	2,600
Austral (Argentina/Chile)	2,100	3,700
Madre de Dios (Peru)	2,800	3,000

Note: Calculated on straight-line distances.
Source: Mission estimates.

7.16 For Bolivia the key strategic aim must be to create a more dynamic industry environment, essentially through the opening up of the São Paulo market. As a major gas surplus country in the region, its interests are best-served by a tighter market, which will give impetus to investment in the country and raise the overall level of prices. However, Bolivia must ensure that it can capture firmer prices through appropriate gas sales contacts that are market-sensitive. It must also be accepted that the future of the Cono Sur market is currently subject to a large number of uncertainties with regard to structure and timing; thus, the emphasis in Bolivia's policy planning must be on flexibility. Further studies of regional gas market development options are recommended.

8

Exports to Argentina

8.1 Argentina has a large and highly developed natural gas industry. Natural gas accounts for 37 percent of total energy demand, one of the highest proportions in the world. Bolivia has been exporting natural gas to Argentina since 1972 under a contract with Gas del Estado, the former state gas monopoly. In 1991 Bolivian imports accounted for 12 percent of total Argentine supplies. The end of Bolivia's privileged long-term contract to sell natural gas to Argentina in May 1992 coincided with the Argentine government's initiative to liberalize the gas market and to privatize Gas del Estado. The structural changes in Argentina's gas industry will force Bolivian gas to compete with Argentine supplies, creating uncertainty about future export prices and volumes. Export prices will certainly fall, although volumes are uncertain in the long-term. This section analyzes the prospects for Bolivian gas sales to Argentina, in the light of the likely development of the Argentine gas market.

8.2 The key strategic issues for Bolivian natural gas export to the Argentine market are the following:

- Understanding fully the changes in the Argentine market and their implications for Bolivia' s future export opportunities and for regional gas trade
- Securing the option of maintaining exports to Argentina on the most favorable terms
- In the case of a long-term delay in sales to Brazil (the low case discussed in chapter 7), maintaining sales to Argentina in the long term
- If sales to Brazil were to materialize sooner (the mid and high cases) managing the linkage between the Bolivian and Argentine markets in the long term.

Natural Gas Demand

8.3 Natural gas demand in Argentina is distributed fairly evenly between the major sectors (a) residential and commercial and (b) industry and power (Table 8.1). Demand has been growing rapidly with growth averaging 7 percent annually during the 1980s. This growth has been based on two key trends: (a) the steady expansion of the

number of consumers in the residential and commercial sectors, in which the need for space heating in the winter months leads to relatively high specific consumption; and (b) the substitution of fuel oil in industry and power. As a result of gas substitution, total fuel oil usage in Argentina fell by 70 percent between 1980 and 1990 (Table 8.2). Argentina's relatively stagnant economy contributed little to the growth of gas demand during this period.

Table 8.1 Argentine Natural Gas Demand, 1980-1990 (mmcmd)

Sector	*1980*	*1985*	*1986*	*1987*	*1988*	*1989*	*1990*
Residential/ Commercial	2,874	4,675	4,950	5,175	5,776	5,516	5,921
Industry	4,053	5,589	6,132	6,432	6,982	6,730	6,539
Power	2,352	3,359	3,403	3,202	4,948	6,606	5,101
CNG	0	4	19	41	89	139	218
TOTAL	**9,279**	**13,627**	**14,504**	**14,850**	**17,795**	**18,991**	**17,779**

Source: Gas del Estado.

Table 8.2 Argentine Fuel Oil Demand, 1980-1990 (mcm)

Sector	*1980*	*1985*	*1986*	*1987*	*1988*	*1989*	*1990*
Industry	1,818	1,031	1,074	1,488	998	871	583
Power	2,903	1,021	1,886	2,135	2,818	1,710	959
Refineries	1,586	1,272	1,217	1,198	1,108	1,096	926
Other	598	150	70	75	79	76	56
TOTAL	**6,905**	**3,474**	**4,247**	**4,896**	**5,003**	**3,753**	**2,524**

Source: YPF.

8.4 An important feature of gas demand in Argentina is its seasonality. Owing to the heating requirement of households, demand in the residential sector in the winter months (July and August) is about five times higher than in the summer (February and March). Owing to shortcomings in the gas production and transmission infrastructure, this fluctuation forces a switch to fuel oil by dual-fired thermal power stations during the winter peak. Thus, there is a significant element of suppressed demand for gas during the winter months. The import contract with Bolivia has not contained a seasonal swing element, which has somewhat increased the swing required from local production. Also noteworthy is the focus on the Buenos Aires region, which accounts for 40 percent of total demand.

8.5 A sectoral analysis of the outlook for gas demand suggests continued annual growth of about 3.5 percent to 2000 (Table 8.4). An important factor driving this growth is an expected increase in economic growth following the macroeconomic measures adopted from the late 1980s. Demand trends by sector are expected to be as follows:

- ***Domestic/Commercial.*** Despite the high penetration rate in this market segment, the number of consumers is expected to continue to grow during the next decade, based on the growth in the number of households (the number of consumers is currently about 4 million). In general, commercial demand is likely to grow along with economic activity.
- ***Industry.*** While there is limited further potential for fuel oil substitution in this sector (fuel oil accounts for about 9 percent of energy use), the revival in economic activity should boost overall energy demand. In addition, a number of large industrial ventures (for example, sponge iron) may be implemented that would have a significant impact on demand.
- ***Power Sector.*** Steam turbine power plants, fueled largely by natural gas, accounted for about 36 percent of Argentina's 12,330 MW of power capacity in 1992, with hydro plants accounting for a similar proportion (Table 8.3). However, a number of large hydro projects are in an advanced stage of execution and by 1996, an additional 2,800 MW of capacity should be available. In addition, the 435 MW Atucha II nuclear power station should also be completed by the mid-1990s. Hence, the share of thermal plant in total capacity will fall to 30 percent in 1996, and the utilization factor of existing plant could also fall. Analysis of power generation costs, however, suggests that gas combined–cycle plants may well be the most economic option for additional capacity. If electricity demand outpaces the planned capacity additions, then a substantial additional requirement for such plants could arise in the late-1990s. The base-case forecast for power generation demand for gas thus shows limited growth until 2000, but substantial growth after that date as additional power requirements are satisfied from higher utilization of steam capacity and new combined cycle plants.

Table 8.3 Argentine Power Sector Capacity, 1992 (MW)

		Low		*High*	
Sector	*1992*	*1995*	*2000*	*1995*	*2000*
Hydro	5,427	6,632	9,420	6,632	10,113
Nuclear	947	947	1,640	947	1,640
Steam (oil/gas)	4,400	4,590	3,895	4,590	3,895
Gas turbine	1,364	1,425	1,425	1,425	1,425
Combined cycle	86	143	143	143	1,853
Diesel	109	58	20	58	20
TOTAL	**12,333**	**13,795**	**16,543**	**13,795**	**18,946**

Source: Gas del Estado.

- ***Feedstock.*** Current natural gas usage for fertilizers and methanol production is relatively modest at 0.6 mmcmd (21 mmcfd). Significant new projects for both uses are planned, although prospects for their implementation depend on the future evolution of gas prices. The base-case forecast assumes that only some of the projects are implemented.

- *CNG.* CNG usage has grown rapidly in Argentina, owing partly to the attractive pricing of CNG in relation to gasoline. From the start of large-scale commercialization in the mid-1980s to mid-1991, the number of CNG fueled vehicles reached 102,000. The base-case forecast takes an optimistic view of future trends, with the total number of vehicles running on CNG expected to reach 340,000 by the year 2000.

Table 8.4 Argentine Natural Gas Demand, 1991-2005 (mmcmd)

Sector	*1991*	*1995*	*2000*	*2005*	*% p.a.*
Residential	16.9	19.6	23.1	27.2	3.5
Industry	18.1	21.2	25.0	27.9	3.1
Power	16.1	17.5	16.3	18.1	0.8
Feedstock	0.6	1.0	2.2	2.2	9.7
CNG	0.8	3.0	4.8	5.0	14.0
TOTAL	**52.5**	**62.3**	**71.3**	**80.3**	**3.1**

Source: Mission estimates.

8.6 The combined effects of (a) uncertainties over the future economic outlook for Argentina and (b) the likely impact of the liberalization of the gas, oil, and power markets could lead to substantial variations with regard to the base case. Key uncertainties are

- The impact of increased domestic natural gas tariffs on residential consumption. The elasticity of demand may be relatively low, however, and an improvement in household incomes may offset the impact of higher tariffs.
- The likely restructuring of the industrial sector as the economy is opened to international competition, with a possible decline of more energy-intensive heavy industries.
- The potential of combined-cycle plants to replace hydro as the major power expansion option in the longer term.
- A possible slower pace of growth in CNG demand, owing to a reduction in its relative price advantage.

Natural Gas Supply

8.7 Argentina's total proven natural gas reserves at end-1990 were put at 536 bcm (18.9 tcf). About 50 percent of these reserves were situated in the Neuquen basin in the center-west of the country, the balance was in the southern Austral basin and the northwestern basin (Table 8.5). Argentina's only discovered giant gas field, Lomo de la Lata in Neuquen, accounted for 158 bcm, that is, 29 percent of the reserves.

Table 8.5 Argentine Proven Natural Gas Reserves, end-1990 (bcm)

Basin	*Proven reserves*	*%*
Neuquen	273	51
(of which Lomo de La Lata)	(158)	29
Northwest	145	27
Austral	102	19
San Jorge	16	3
TOTAL	**536**	**100**

Source: YPF.

8.8 Domestic production supplies 88 percent of demand, with Bolivian imports supplying the remainder. Because Bolivian imports have been roughly constant since the late 1970s, production has grown in line with demand. The pattern of production development has largely been dictated by the growth of pipeline capacity. Hence, output in the North and South has stagnated since the early 1980s, when the last major pipeline expansions were undertaken. All growth has come from the Neuquen basin where the inauguration of the Neuba II pipeline in 1988 substantially increased capacity. This development reflects the lower incremental costs of delivering gas from Neuquen to the major market, Buenos Aires.

Table 8.6 Argentine Natural Gas Demand and Supply, 1980-1990 (mmcm)

Item	*1980*	*1985*	*1986*	*1987*	*1988*	*1989*	*1990*
Production	13,274	19,170	19,245	19,168	22,734	24,206	23,018
Field/gas plant use	1,741	1,759	1,785	1,716	1,799	1,907	2,025
Reinjected	462	826	497	477	557	836	721
Vented/flared	3,285	3,566	2,817	2,403	2,951	2,687	2,632
Domestic market production	7,786	13,019	14,146	14,572	17,427	18,776	17,640
Imports from Bolivia	2,270	2,377	2,349	2,291	2,403	2,417	2,391
TOTAL MARKET SUPPLIES	**10,056**	**15,396**	**16,495**	**16,863**	**19,830**	**21,193**	**20,031**

Source: Gas del Estado.

8.9 About 11 percent of gas production is vented or flared. Most of this gas either has a very high carbon dioxide or hydrogen sulfide content or is produced in small remote oil fields, where the economics of gas gathering are unattractive.

8.10 Argentina's true gas resource potential is uncertain, because in the past there has been too limited investment in gas-oriented exploration. This is explained by shortages of capital on the part of YPF (the former state oil company) and limited incentive to private companies, owing to low prices and the requirement to sell to the state companies. The reserves survey undertaken in conjunction with the World Bank's Argentine energy sector study in 1989 put probable reserves at 215 bcm. Other recent figures concur with these orders of magnitude. Perhaps, the major uncertainty on possible reserves is in the Austral basin, where offshore exploration has indicated substantial new

reserves. Estimates by the operator, Total, have put possible reserves in its offshore area at over 142 bcm with a 50 percent probability.

Gas Pipeline System

8.11 Argentina has a vast system of transmission pipelines, generally designed to carry gas from the three gas-producing basins toward the consumption center of Buenos Aires and cities en route. The characteristics of these pipelines are shown in Table 8.7. System capacity is generally inadequate to meet demand, especially during the winter peak. Both the northern and southern pipelines are at full capacity in the winter, and being in relatively poor condition, they have limited scope for further compression or looping. Construction of new parallel pipelines would only be justified by relatively high transport tariffs. The western pipelines are generally in better condition and have substantial scope for capacity expansion at a modest incremental cost, especially in the case of Neuba II. Moreover, because the lines are interconnected around Buenos Aires, the Western pipeline can relieve the pressure on the northern and southern lines by back feeding supplies up these lines. Hence, it is likely that in the medium term (until the late 1990s) nearly all growth in demand in Argentina will be met from the Neuquen basin.

Table 8.7 Argentine Natural Gas Pipelines

System	*Length (km)*	*Diameter i(n.)*	*Nominal capacity (mmcmd)*	*Volume 1990 (mmcmd)*	*Average utilization (%)*
Northern	2,877	24	14.2	11.1	78.1
Western	2,449	24	9.5	8.4	88.4
Neuba II	1,371	36	15.3	11.5	74.9
Center-west	1,507	30	11.4	10.6	92.9
Southern	4,390	30	15.4	13.4	86.7

Source: Gas del Estado.

8.12 Argentina's natural gas industry has been developed as a state monopoly by Gas del Estado, which handled most gas processing and all transmission and distribution. Until recently, 75 percent of proven reserves were operated by YPF, and the remainder by various private companies. All private companies had to sell their supplies to YPF, on terms that gave limited incentive to explore or develop gas fields. Gas prices to consumers were set by the government and contained various subsidies and distortions.

8.13 Since 1989 a process of liberalization of the gas and oil markets has been underway. This culminated in the privatization of Gas del Estado by end-1992 and of YPF in 1993. The structure of the industry after privatization is meant to follow a model that maximizes competition, with a strong regulatory framework to cover the areas of transmission and distribution, where natural monopolies prevail. Key features of the liberalized industry are the following:

- The industry consists of two private gas transmission companies (north and south), several private distribution companies, and a multiplicity of gas producers (in part achieved through sales by YPF of existing gas fields).
- Participants in each element of the gas chain are prevented from owning a controlling interest in any other part of the chain (for example, producers are not able to have control of pipelines), a provision designed to maximize market transparency.
- Transporters and distributors move gas at tariffs set by a gas regulatory agency, which also has overall regulatory oversight of the industry, with independence from government and strong autonomous powers.
- Pipelines operate on an open-access basis, with producers having the right to sell directly to large consumers, bypassing distributors if they wish.
- Gas transmission companies are not allowed to buy and sell gas on their own account, a provision designed to ensure fair access to capacity for all users of pipelines.
- Wellhead prices for gas are thus set by competition among suppliers for sales to large consumers (including distribution companies), and the parallel competition among consumers to purchase gas directly from suppliers.
- Imports of natural gas may be made freely without state control; however, exports must be authorized by the government, although this permission may not be unreasonably withheld.

Supply-Demand Balance

8.14 In assessing the likely development of the Argentine gas market in the liberalized market framework, it is important to distinguish between the medium and longer term market trends. A projection of potential supply from the major Argentine basins shows that proven reserves are adequate to meet domestic demand in the medium term, but that reserve-to-production ratios will fall to critical levels by the late 1990s in the absence of new reserves (Table 8.8). As the table shows, assuming that production maintains a R/P ratio of 15-to-1, a supply deficit of 12.70 bcm/yr is reached by 2005. These estimates assume that Bolivian imports cease from 1994 onwards, when the current commitment by Argentina to purchase Bolivian gas expires (Table 8.8). The projections also exclude planned exports to Chile.

Table 8.8 Argentine Natural Gas Supply and Demand Balance, 1991-2005 (bcm)

Balance item	*1991*	*1995*	*2000*	*2005*
Total demand	19.17	22.75	26.03	29.31
Total deliveries	19.17	22.75	23.45	16.61
North	1.79	4.40	7.48	5.30
Neuquen	9.95	12.85	11.34	8.03
South	5.20	5.50	4.63	3.28
Bolivian imports	2.23	0	0	0
Reserves/Production				
North	82	31	15	15
Neuquen	28	18	15	15
South	23	17	15	15
Deficit	0	0	2.58	12.70

Source: Mission estimates.

8.15 In the medium term, market dynamics will be mainly determined by pipeline capacity constraints. When potential deliverability to a pipeline exceeds pipeline capacity, wellhead prices will fall as producers compete for space in the pipeline. This can be overcome in part by preallocating capacity rights, and there are indications that the Argentine government intends to do so in some cases.

8.16 In the longer term, development of new pipeline capacity to meet market needs is likely to lead to a better balance between potential supply and demand. As indicated above, the initial expansion of capacity is likely to be from the Neuquen basin, with the northern and southern pipelines unlikely to be greatly expanded before the late 1990s. Any local oversupply in the medium term is likely to be most marked in these areas.

8.17 Clearly, if Argentina is to continue to meet its domestic requirements into the next century, additional supplies will have to be obtained. The most likely resolution of this problem, within a liberalized gas market, will be through a combination of higher prices in the Argentine market and the development of currently unproven reserves. In addition to the probable and possible reserves indicated above, Argentina is likely to have substantial reserves in structures that have not yet been drilled or fully defined through seismic survey. It is likely that these additional reserves will emerge following increased future exploration.

Bolivia's Gas Export Contract

8.18 Bolivia has been exporting natural gas to Argentina since 1972. Under the contract that expired in April 1992, volumes were set at 6.1 mmcmd (215 mmcfd) and the price of the gas was linked to oil products. A relatively high base price meant that the prices received by Bolivia were well above those prevailing in Argentina. For example,

the average price received by Bolivia in the last quarter of 1991 was US$2.40/mmBtu at the border. At this time, delivered sales prices in Argentina were US$2.40/mmBtu for industrial consumers and US$2.00/mmBtu for power. Argentine producers generally received about US$1.00/mmBtu for their sales to YPF/GdE.

8.19 With the ending of the previous sales contract in May 1992, a transitional agreement has been signed between Bolivia and Argentina. This agreement provided for Bolivia to continue selling the same volumes of natural gas to Argentina (as previously) until December 1993, but at a price of US$1.00/mmBtu. This price was intended to be competitive with domestically produced Argentine gas in the northern region. In addition, Argentina is to transfer some US$110 million to Bolivia.

8.20 Since December 1993, Bolivia has had free access to the Argentine market. From December 1993, for four years, Bolivia will continue to be able to sell up to 6.1 mmcmd to Argentina. YPF will have first option to buy this gas at a price equal to the best offer received by YPFB in the market, or in the absence of such a price, at a price to be freely negotiated. If YPF chooses not to buy the gas, YPFB will have the right to utilize the capacity of the northern pipeline in Argentina, up to the 6.1 mmcmd maximum volume. If YPFB chooses to withdraw from the Argentine market at any time during the four years in question, YPFB must give YPF notice of intent of at least 180 days.

Prospects for Bolivian Gas Exports to Argentina

8.21 The ability of YPFB to continue to utilize the capacity of the northern pipeline allows Bolivia effectively to continue to sell up to 6.1 mmcmd (215 mmcfd) to Argentina up to the end of 1997. After December 1993, however, the prices at which these sales take place are determined by market forces, and at present, future prices are very difficult to predict. There is a risk to Bolivia of lower prices. Moreover, the agreement effectively guarantees Bolivia access to the capacity of the pipeline only up to current volumes. Although theoretically possible under Argentina's open gas market, volumes above this level may not be absorbed by the Argentine market. In the longer term, beyond 1997, the key issue for Bolivia is whether there will continue to be an attractive market for Bolivian gas in Argentina.

8.22 The prospects for Bolivian exports to Argentina depend on the supply-demand situation in northern Argentina. A major problem for Bolivia is coping with local oversupply in the medium term and with competition from domestic Argentine resources in the longer term.

8.23 Supplies of gas into northern Argentina derive from three main sources: (a) the Ramos field, operated by the Argentine private firm Pluspetrol; (b) the Aguarague field, currently operated by YPF; and (c) gas imports from Bolivia. Bolivia's imports, together with a part of Argentine production, are processed at the Campo Duran gas separation plant, from which LPG's and natural gasoline are extracted. Because of constraints on the northern pipeline capacity, part of the natural gas is reinjected into the largely depleted Campo Duran field.

8.24 A major constraint on supplies from the north of Argentina is the capacity of the northern pipeline. This pipeline has a maximum operating capacity of 14.2 mmcmd (500 mmcfd). Seasonal variations in demand mean, however, that throughput actually swings between a low point of about 9 mmcmd (320 mmcfd) in the summer months and a high point of 13.5 mmcmd (480 mmcfd) in the winter months, for an annual average of about 11 mmcmd (390 mmcfd). The northern pipeline was built in 1960 and was expanded in 1970 with the construction of a parallel pipeline as far as Tucuman. Although there has been some rehabilitation investment in the pipeline in recent years, it would be difficult to increase its capacity significantly without major investment.

8.25 The northern pipeline is the exclusive supply to markets in the north of Argentina. However, further down the pipeline (south of Cordoba), markets are supplied both with gas from the northern pipeline and through the other pipelines carrying gas to Buenos Aires. The ability of lower segments of the pipeline to handle gas flow in both directions is an important point of flexibility in the marketing of gas from this pipeline.

8.26 Relative to this demand, total production capacity in northern Argentina from current wells is about 9.7 mmcmd (340 mmcfd), including 5 mmcmd (175 mmcfd) in Ramos and 4.7 mmcmd (165 mmcfd) in Aguarague. When combined with Bolivian imports, this gives a delivery capacity of some 15.8 mmcmd (560 mmcfd) compared with the pipeline requirement and capacity of 11 mmcmd (390 mmcfd).

8.27 A factor that could aggravate oversupply is the expansion during 1992 of the Campo Duran processing plant, from 9 mmcmd (320 mmcfd) to 16.5 mmcmd (580 mmcfd). This will be accompanied by an expansion of reinjection capacity for Campo Duran from 0.8 mmcmd (28 mmcfd) to 2.7 mmcmd (95 mmcfd). Nonetheless, the need to keep the plant fully loaded will create an incentive to keep up production capacity.

8.28 This surplus deliverability in the short-to-medium-term is likely to lead to downward pressure on gas prices in northern Argentina as the Argentine market is liberalized. However, it is difficult to predict precisely how market prices will develop owing to the large number of uncertainties involved. These uncertainties, and further likely changes in the structure of production in the northern region, include the following:

- The government of Argentina intended to sell YPF's stake in Aguarague during 1992 or 1993. The strategy of the new owner toward reserves development and gas sales will determine market development.
- The production capacity may be largely preallocated through long-term contracts. Pluspetrol has a contract with YPF for gas sales. The Bolivian gas export agreement effectively gives Bolivia priority, although the sale of Aguarague may also involve a gas sales contract.
- The need to keep up utilization of the expanded Campo Duran processing plant will create an incentive to continue to import Bolivian gas, including liquids, at least until domestic Argentine production can be fully developed.

- There is the potential for further gas production in the basin, particularly in the Acambuco area operated by the company Bridas, where deep gas has been discovered and further drilling is planned in 1992-1993, although no producing wells have as yet been completed.

8.29 In these circumstances, gas prices in the short and medium term (between 1994 and 1997) could fluctuate within a wide range. Particularly in the summer months, the bottom to prices will be set, in theory, by the short-run operating cost of production—judging by Bolivian costs, this would be no more than US$0.25/mcf. It may pay producers, however, to continue producing even at zero prices, when the value of liquids is taken into account. Moreover, the type of contract that producers have with the owners of the gas-processing plant, who will want to keep up capacity, may well lead to gas being sold at whatever the market will bear. A theoretical maximum to prices would be the netback price of gas in the north, based on the cost of substitutes. Using fuel oil as the marginal substitute and a theoretical tariff for the northern pipeline to Buenos Aires, the netback would range from US$1.00 to US$1.50/mcf. In practice, prices will probably fluctuate within this range depending on a number of factors, including the proportion of total pipeline capacity that is preallocated to producers, the strategies of individual producers in terms of selling or conserving (reinjecting) gas, and the degree of gas-to-gas competition in the southern portion of the northern pipeline.

8.30 In the longer run (beyond 1997), the potential for Bolivian gas sales to Argentina will depend on the overall supply-demand balance in the market. If significant additional supplies are not developed during the 1990s from the Neuquen, it is likely that there will be pressure to increase deliverability from the North because this may be cheaper than expanding the southern pipeline from the Austral basin. In this case, supplies from Bolivia may be needed to meet market demand in Argentina.

8.31 On the assumption that additional supplies from the Neuquen can meet market demands in the later 1990s, there will be no early requirement to expand deliverability from the North. In this case, in principle, development of the Argentine fields (Ramos and Aguarague) could meet nearly all of the requirements of the domestic market. This case would correspond to either the mid or high cases for the Cono Sur. Bolivian gas could be diverted to the São Paulo market, with gas from the Austral basin eventually making up the shortfall in the Argentine market through expansion of the southern pipeline.

Strategy for Bolivian Gas Exports to Argentina

8.32 Bolivia's strategy toward Argentina must take into account the fact that the Argentine market will be the largest single influence over the course of the gas market in the entire Cono Sur area. A fundamental feature of Bolivia's strategy toward Argentina is thus to understand developments in that gas market required to make the necessary policy decisions.

8.33 In the medium term, Bolivia should take a number of actions to strengthen its position as a gas exporter to Argentina.

- MEH staff should be dedicated to following developments in the rapidly changing gas industry in Argentina. These staff should familiarize themselves with all facets of the Argentine industry, including the legal and regulatory framework, the supply-demand situation, and the major producers and consumers, particularly within the northern half of the country in which Bolivia's gas is likely t compete.
- MEH staff should be complemented by parallel staff in YPFB, who should have a specific focus on marketing Bolivia's gas to Argentine consumers. The activity of these marketers should help to ensure the maximum price for Bolivian gas in the Argentine market. Although individual firms in Bolivia should have the right to sell directly into Argentina, the nature of the agreement between the two countries gives YPFB a specific position as the principal marketer of gas. As discussed elsewhere (chapter 12), YPFB's gas export marketing should be done through an independent specialized subsidiary that operates on commercial principles.
- Bolivia has a clear interest in the earliest possible expansion of the northern pipeline system because this increases Bolivia's ability to sell gas into Argentina, without increasing the downside price risk. Therefore, Bolivia should be prepared to support any expansion proposal before the regulator in Argentina, should this be required. In addition, YPFB or other Bolivian companies should be encouraged to participate, in any capacity, in commercial expansion schemes.
- The new major market for gas that could emerge in northern Argentina is in combined-cycle power generation. This area should be monitored closely by MEH, and Bolivia should lobby for policies within Argentina that allow free and fair competition between gas power generation (especially by independent generators) and other power sources. Participation by Bolivian firms in commercial joint ventures should also be encouraged.
- Bolivia should study the option of using its flexibility in gas storage at Rio Grande and elsewhere to improve the efficiency of regional gas deliveries in Argentina. In particular, Bolivia's flexibility to store gas and deliver variable quantities on a seasonal basis could provide one justification for the early expansion of the northern pipeline, in comparison with one from Neuquen because a larger northern pipeline would reduce the need to build gas storage in Argentina.
- Bolivia should keep open the option of supplying some gas to Argentina even in the event of selling large volumes to Brazil, because Southern Bolivian supplies, that are close to the Argentine border, may well have a higher value in nearby Argentine uses than in sales to Brazil through a reversed Yacuiba-Rio Grande line. There may be a need for dedicated pipelines for these reserves, as is currently the case with the Bermejo field.

8.34 In the longer term, Bolivia's strategy will of course depend on the evolution of the Argentine market. In the low case for the Cono Sur (chapter 7), without the development of the São Paulo market, the ability to maximize volume and prices in the Argentine market will be key to Bolivia. In a tight Argentine market, with open access to pipelines, there may be limited need, however, for MEH to do anything other than allow Bolivian producers to compete freely in the Argentine market, particularly as the northern pipeline is expanded. In the mid and high cases, with most Bolivian exports going to São Paulo, developments in the Argentine market will still be the key to overall Cono Sur gas market trends.

9

Exports to Brazil

9.1 Brazil, particularly the São Paulo area, represents the key opportunity for increased Bolivian gas exports. Accessing the São Paulo market would require a 1,900 km-long pipeline from the Santa Cruz area at a cost of at least US$1.0 billion. To justify such a pipeline, sales volume for Bolivian gas in Brazil would have to build up rapidly, and the city gate price of gas would have to include a large transport tariff. In contemplating exports to Brazil, the central issue for Bolivia is thus the potential size of the market, and the value of gas in that market in relation to the cost of delivering gas. This chapter focuses on these issues.

9.2 In the following section, the potential market for natural gas in São Paulo and its economic and financial values are assessed. It should be borne in mind that the market values and size estimates presented are only reference points for negotiating an exports contract for Bolivian gas. In practice, the final values and price obtained in these negotiations will not manage to capture the full value or potential of gas in the end-user market.

Energy Resources in Brazil

9.3 Brazil is relatively well-endowed with energy resources, both renewable and nonrenewable. According to the National Energy Balance, the proven energy reserves in 1989 included 379 mmtoe of oil, 106 mmtoe of natural gas, and 3,882 mmtoe of coal. The annual capacity of the hydropower system amounted to 271 mmtoe. In addition, there are substantial deposits of shale oil, shale gas, uranium, and peat, but their economic potential is far less promising. Of major significance in the Brazilian energy situation is renewable energy, in particular, biomass (mainly bagasse and fuelwood) and hydropower. Renewable energy accounted for nearly 60 percent of primary energy consumption in 1990. Considering the contribution of domestic fossil fuels (mainly oil and coal) to total energy needs, energy self-sufficiency has increased from 63 percent in 1979 to 84 percent in 1986 and has remained over 80 percent in recent years.

9.4 After a peak at 188 mmtoe in 1989, the consumption of primary energy dropped by 5 percent to 180 mmtoe in 1990, owing to the general economic situation of

the country. The rising consumption pattern has resumed since 1991. Over the past two decades (1970-1990), the average annual increase was 4.5 percent. Consumption patterns did not show major changes with regard to the shares of renewable and nonrenewable energy, as well as within nonrenewable energy sources. The share of nonrenewable energy rose slightly from 37 percent to 40 percent, led by natural gas and metallurgical coal; petroleum remained constant. Regarding renewable energy, however, the share of hydropower and sugar cane derivatives more than doubled over this period to 33 percent and 10 percent, respectively. This increase represents a five-fold growth in absolute terms over 20 years, whereas the share of wood fell from 43 percent to 15 percent, with wood consumption remaining constant in absolute terms.

9.5 Proven reserves of natural gas rose to 133 bcm (4.7 tcf) by the end of 1992, an increase of 7.4 percent compared with the previous year. Nonproven reserves are an estimated 164.9 bcm (5.8 tcf) for an overall total of 288.7 bcm (10.2 tcf).[15] The reserves of natural gas almost doubled during 1981-90, representing more than 20 percent of Brazil's total hydrocarbon reserves in 1990. Based on 1991 production levels, the R/P is 24 years, compared with 12 years for oil. With the exception of the remote Ucuru Basin in the Upper Amazon, natural gas reserves are fairly well distributed across the country, most fields being located in areas along the coast where transmission to consumption centers has been possible. The bulk of the reserves are in the Campos Basin (off Rio de Janeiro State), the Ucuru Basin, and in the Merluza field (in the Santos Basin, off the São Paulo coast). Of the reserves, 60 percent are associated gas and 40 percent are nonassociated.

9.6 The production of natural gas in 1992 averaged 18.1 mmcmd (640 mmcfd), of which 3.8 was reinjected, 3.1 flared, 3.1 used internally by Petrobras, and 9.1 mmcmd (320 mmcfd) marketed to various customers. In 1990, 1.9 mmcmd was used as raw material for the production of fertilizers and petrochemicals by Petrobras subsidiaries, and 0.4 mmcmd for the production of sponge iron through the reduction of iron ore; the remaining 5.3 mmcmd (187 mmcfd), that is, 31 percent of the total production, was sold on the commercial market. Although the share of natural gas in energy use is steadily increasing, it represented only 2.3 percent of final energy consumption in 1990. For planning purposes, Petrobras has developed two production and delivery scenarios that cover the 1991-2001 decade. The *basic scenario* is based on the operation of existing reserves and takes into account projects already implemented, as well as those that are only in the study phase and have no financing in place as yet. Under this scenario, the total production should reach 35 mmcmd (1.24 bcfd) in 1995 and then slightly decrease to 33 mmcmd (1.17 bcfd) by the turn of the century.[16] The marketed production would remain about constant at 20 mmcmd (0.71 bcfd) from 1995 on, about

[15] Any information relating to the magnitude of existing reserves, evaluation of the prospects for new discoveries, projections of the future rates of production, and availability of all types of hydrocarbons provided solely by Petrobras.

[16] Total production, minus gas reinjected, flared, and consumed by Petrobras for its own activities.

half of this amount being allocated to the south and southeast regions.[17] The *new discoveries scenario* is more ambitious and considers the exploitation of substantial reserves not yet discovered but with reasonable geological probability. Based on these assumptions, total production would reach 40 mmcmd (1.41 bcfd) in 1995 and 71 mmcmd (2.5 bcfd) in 2001, and marketed production would almost double between 1995 (24 mmcmd [0.85 bcfd]) and 2001 (47 mmcmd [1.66 bcfd]), about half of these quantities being allocated to the south and southeast regions (12 and 25 mmcmd [0.42 and 0.88 bcfd], respectively).

9.7 All transmission pipelines are owned and operated by Petrobras, with the exception of the sea line connecting the Merluza offshore field to Cubatao, was constructed by Pecten, the Shell subsidiary that discovered the field. The total length of the transmission lines is nearly 4,000 km, which was installed since 1980. Owing to the size of the country and the geographical distribution of the fields, there is no countrywide interconnected pipeline system, and any such system is unlikely. Existing infrastructure consists of five isolated local networks located along the coast; they connect the fields mainly to industrial customers and to some major cities, including Rio de Janeiro and São Paulo.

9.8 The State of São Paulo, with a population of 31 million, an area of 248,000 square km, and an economy estimated at US$120 billion in 1990, accounts for 21 percent of the population, 3 percent of the landmass, and 38 percent of the total economic output of Brazil. The economic predominance of the state within the country is reflected in the pattern of energy use. According to the Energy Balance of the State of São Paulo for 1988, the last year for which complete statewide data exists, the gross internal supply of primary energy reached 44 mmtoe, that is, 24 percent of the national total. In terms of final energy, the consumption amounted to 26.7 mmtoe, representing about 28 percent of Brazil's total consumption, 27 percent of petroleum, and 35 percent of electricity. Industry and transportation represented 49 percent and 33 percent, respectively; this consumption is well ahead of the residential (10 percent), commercial (3 percent), and public and agriculture sectors (5 percent). Oil products represented 45 percent, biomass 26 percent, and electricity 21 percent, the remainder consisting of coal (4 percent), manufactured gases (2 percent), and industrial residues (2 percent).

9.9 Town gas has been supplied to São Paulo consumers since the end of the nineteenth century. Town gas is currently produced in two naphtha cracking plants built in the first half of the 1970s. These plants can jointly produce a maximum of 1.4 mmcmd (49 mmcfd) of manufactured gas, equivalent to 0.6 mmcmd (25 mmcfd) of natural gas.[18] The plants were operated near full capacity until 1991; they are now operating at only half their capacity, owing to the conversion of some industrial customers to natural gas. Town gas is distributed mainly to residential and commercial customers through a 840 km, cast iron network. Natural gas consumption started when the 22-in., 314 km-long

17 States of Espiritu Santo, Rio de Janeiro, São Paulo, and Parana.

18 HHV of town gas and natural gas in São Paulo are 4100 and 9400 kca/cm, respectively.

pipeline connecting Volta Redonda, in the western part of the State of Rio de Janeiro, to São Paulo was put on stream in 1988. The pipeline enabled Comgas, the state-controlled gas utility, to be provided by Petrobras with natural gas from the Campos Basin, located more than 700 km east of São Paulo. By September 1992 Comgas was distributing both natural gas and town gas to 459 industries and to 4,732 commercial and 226,183 residential customers. Natural gas sales amounted to 1.1 mmcmd (39 mmcfd), almost entirely consumed in the industrial sector, and town gas amounted to the equivalent of 0.31 mmcmd (11 mmcfd) of natural gas, 81 percent of that supplied residential and commercial customers. In addition, Comgas supplies limited quantities of LPG to 5,670 residential customers and 56 commercial customers. Total amount of LPG sold was about 160 tons in September 1992, equivalent to 6,630 cmd natural gas.

Table 9.1 Consumption Town and Natural Gas in São Paulo (September 1992)

	Town Gas		*Natural Gas*	
Sector	*Number of consumers*	*Consumption (cmd NG-eq.)*	*Number of consumers*	*Consumption (cmd NG-eq.)*
Residential	220,065	162,935	6,118	5,385
Commercial	4,693	99,964	39	21,718
Industrial	274	61,181	185	1,050,628
CNG	--	--	3	14,511
TOTAL	225,032	314,078	6,345	1,092,242

Note: Consumption is indicated in cmd of natural gas equivalent.
Source: Mission estimates.

9.10 In February 1987 Petrobras and Comgas signed an agreement according to which Comgas would receive gradually increasing natural gas quantities, up to 3 mmcmd (106 mmcfd) as of January 1991. The gas was to come in equal quantities from Campos and from the Merluza field, and corresponds to the São Paulo allocation within Petrobras' basic scenario. On this basis, Comgas had undertaken an ambitious expansion program that included (a) the conversion of the town-gas network and of town gas customers to natural gas; (b) the connection of new customers located within the current town-gas area; and (c) the extension of the natural gas distribution networks to supply new industrial consumers as well as a limited number of residential and commercial customers located near the industrial areas. This US$258 million project, known as São Paulo Gas Distribution project, is funded by a US$94 million loan from the World Bank and will be completed in 1995. According to the project, 83 percent of natural gas (2.5 mmcmd [88 mmcfd]) will supply a total of nearly 700 industrial customers, of that 460 are currently using either town gas or natural gas. The balance (0.5 mmcmd [18 mmcfd]) will enable Comgas to nearly double its current residential and commercial sales, supplying a total of 413,000 residential and nearly 5,000 commercial customers. Another World Bank–supported project, the Hydrocarbons Transport and Processing project, includes a component on the construction of the 12-in., 42 km-long missing link between

the Cubatao Refinery near Santos,[19] and the Volta Redonda-São Paulo gas trunk line, that will enable Petrobras to make Merluza gas available in the greater São Paulo area.

9.11 To date, because of delays in the development of field facilities, Petrobras has been unable to provide Comgas with the contractual gas quantities, and delivered only 1.1 mmcmd (39 mmcfd) natural gas from Campos in September 1992 instead of 1.5 mmcmd (53 mmcfd). Natural gas from the Merluza field started reaching industrial consumers in the area of the harbor city of Santos in early 1993. The committed amount is 1.2 mmcmd (42.4 mmcfd) on the plateau. Considering that the two above projects will be completed well before the pipeline from Bolivia is commissioned, the following sections present net consumption forecasts, that is, the part of the potential market that remains available for Bolivian gas, after having deducted the gas quantities already committed between Petrobras and Comgas.

Industrial Sector

9.12 The total industrial sector consumed 12.7 mmtoe in 1988. Most of the energy was consumed in basic industries, including food and beverage (34 percent),[20] metallurgy (22 percent), chemicals (11 percent), pulp and paper (8 percent), and construction materials (7 percent). Considering its intrinsic physical and chemical qualities, with a few exceptions, natural gas can be used as a fuel or raw material in all industrial activities and can substitute for almost any type of energy. Owing to economic constraints, the likely market is much smaller than the physical potential market because (a) the cost of gas transport by pipeline makes it necessary to supply gas only to those large industrial areas where a significant potential market enables economies of scale in both transmission and distribution pipelines; (b) natural gas cannot compete with some energy sources that derive from industrial processes and are produced at no or low cost, such as industrial residues (for example, bagasse, wood residues, black liquor, tail gases) that are widely used in Brazil; and (c) despite of its high versatility, natural gas cannot easily be substituted for certain energy sources, including high-cost electricity, because this would imply, in some cases, a complete and thus unaffordable modification of the industrial process. In addition, the use of gas in grass-root projects as a raw material for producing petrochemicals and fertilizers has not been considered in the study because these uses have not been estimated to be attractive.

9.13 After having removed from the data base those factories that appear unsuitable for gas for either technical or economic reasons, the remaining likely market (basis 1988) amounts to 10.4 mmcmd (0.31 bcfd) distributed across 660 large- and medium-size factories (more than 1,000 cmd of potential gas consumption). This figure corresponds to 25 percent of the overall energy consumption of the industrial sector in the State of São Paulo. This potential market is located in six major industrial areas

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19 Outlet of the Pecten sealine from the Merluza field.

20 Brazilian statistics include the production of alcohol from sugar cane in the food and beverage subsector, whatever the destination of the end-product.

throughout the state, including the greater São Paulo area (42 percent) and the harbor city of Santos and the Campinas area (19.5 percent each). Although the chemical subsector is the major potential subsector (28 percent), four medium-size subsectors (textile, pulp and paper, food and beverage, and nonferrous metallurgy) represent between 9 and 12 percent each, the balance comprising various components of the construction materials industry (cement, glass, ceramics), as well as secondary metallurgy. Representing 54 percent of the substitutable consumption, fuel oil is by far the most significant fuel, evenly split between high-and low-sulfur products, and other oil products (LPG, diesel oil, and naphtha) together represent a mere 2 percent. Among other energy sources, biomass (wood and charcoal), electricity (limited to thermal uses only), and coal account for 16 percent, 9 percent, and 8 percent, respectively; refinery gas (10 percent) and town gas (1 percent) make up the remainder.

9.14 After a continuous increase, energy consumption fell in the State of São Paulo in 1990, as it did in the rest of the country (Table 9.2). From there on, it was assumed that the energy demand would follow the growth rates established by the World Bank in 1992.[21] Based on these figures, the weighted average annual growth rate of energy consumption in the industrial sector would range between 2.6 percent and 3 percent leading to a potential market of 11.6 mmcmd in 1995, 13.4 mmcmd in 2000, and 16 mmcmd in 2010 (410, 463, and 565 mmcfd, respectively). The estimated gas consumption has been derived from the above potential market and from the ability of gas to meet the potential demand, that is, the economic benefit that gas is likely to bring to the potential consumers. In turn, the latter depends on several factors (a) the cost of the competing fuels, (b) the costs of converting the thermal equipment and of connecting to the network, and (c) the savings that gas would generate through efficient operation and maintenance of the equipment. In addition, gas penetration will increase during the first years of operation, as industrial networks expand and potential consumers become more aware of the benefits of natural gas. Based on a penetration grid established along these lines, natural gas is expected, at the end of the buildup period, to have substituted for 72 percent of the potential fuel oil market, 50 percent of wood, and 36 percent of electricity (thermal uses). Natural gas consumption will reach 1.9 mmcmd in 1997 (first year of operation), 6.9 mmcmd in 2000, 10.2 mmcmd in 2005, and 12 mmcmd in 2010 (67, 243, 360, and 424 mmcfd, respectively). Overall penetration factors will reach 53 percent, 69 percent, and 71 percent of the potential market, respectively.

[21] Brazil: Energy Pricing and Investment Study, February 1992.

Table 9.2 Potential Market of the Industrial Sector in the State of São Paulo), 1991 (mcmd NG-eq.)

Substitutable fuel	*mcmd NG-eq.*	%
High-sulfur fuel oil (HSFO)	2,782	26.7
Low-sulfur fuel oil (LSFO)	2,847	27.3
Refinery gas	1,069	10.3
Steam coal	549	5.3
Coking coal	380	3.6
Wood/charcoal	1,646	15.8
Electricity	816	7.8
Other	330	3.2
TOTAL	**10,418**	**100.0**

Source: Mission estimates.

9.15 In addition to the demand for thermal processes, natural gas would open possibilities for industrial cogeneration based on gas turbines, whenever a balanced demand for heat and power exists. The additional potential demand for cogeneration in the larger industries (that is, those with a potential demand over 20,000 cmd for thermal process) is 626 MW, resulting in a potential demand of 1.2 mmcmd (42 mmcfd) of natural gas. Considering similar penetration factors (a factory converted to gas for its industrial process is likely to consider gas for other applications), cogeneration would induce an additional gas demand of 0.8 mmcmd in 2000, 1.2 mmcmd in 2005, and 1.4 mmcmd in 2010 (28, 42, and 49 mmcfd, respectively).

Power Generation

9.16 The Brazilian power sector is characterized by its large size and by the considerable share of hydro capacity. Out of a total installed capacity of 55.2 GW (1990),[22] 92 percent was hydro, 7 percent conventional thermal, and 1 percent nuclear. Owing to cheaper operating costs, the share of hydro is even larger with regard to the amount of electricity generated (97 percent). After tremendous growth in the 1970s (12.2 percent per year on average), the annual growth rate of electricity demand has significantly decreased in the following decade (9.2 percent during 1981–85, and 4.5 percent in 1986–90). The latest official consumption forecasts are based on slightly higher, although moderate, rates of increase until 2005, ranging about 5.3 to 5.7 percent per year. Consumption is expected to reach 260 TWh in 1995, 343 TWh in 2000, and 452 TWh in 2005.

9.17 São Paulo is supplied by an interconnected system in the South-Southeast-Midwest (SSM) regions (where 77 percent of the total capacity of the country is installed) that produced over 80 percent of the total 205 TWh generated in Brazil in 1990. Projected

[22] Not including 3.3 GW from auto producers.

regional growth rates to 2005 are slightly lower than for the entire country because the overall demand is expected to be driven by the residential rather than the industrial sector, that is, by the underequipped Northeast rather than by the already industrialized South-Southeast. Consumption in the SSM system is expected to rise from 160 TWh in 1990 to 201 TWh in 1995, 259 TWh in 2000, and 334 TWh in 2005, which corresponds to growth rates ranging from 4.7 to 5.2 percent.

9.18 In terms of generating capacity, the official 10-year expansion plan (1991-2001) for the SSM system, established in 1990, was revised in March 1992 under two scenarios that take into account the strong physical and financial constraints faced by power utilities in meeting their initial implementation schedule. The additional 31.2 GW that were initially planned to be put on stream between 1991 and 2001 are now expected to be available, at the earliest, by the end of 2002 (Scenario 1), and most probably even later (Scenario 2). The concern is that even a relatively mild resumption of economic activity could result in excessively high risks of rationing. Under Scenario 2 (but even this scenario is regarded as optimistic by some power utilities), the risk of a deficit (that is, the statistical chance of demand exceeding supply in a given year) ranges between 10 and 14 percent from 1997 on. Moreover, the risk of any deficit exceeding 10 percent of the projected demand exceeds 5.5 percent in any year from 1997 on. Based on the demand projections presented above, a deficit of 10 percent implies a gap between demand and supply capacity of 5.8 GW in 1997 and 9.1 GW in 2001, which means that the potential demand for natural gas-fired power plants may turn out to be quite substantial.

9.19 In addition, the potential for natural gas is even higher when considering the options of (a) substituting natural gas-fired plants for those hydro plants, the construction of that is decided but has not yet started and (b) converting existing thermal oil-fired plants to natural gas. Preliminary findings based on a comparison of the economic cost of generating power in both hydro and natural gas plants in the SSM system show that the potential for gas is promising. Under standard assumptions,[23] the cost of generating power in a gas-fired combined-cycle power plant is estimated at 46.1 US$/MWh. According to the revised 10-year expansion plan, out of a total of 52 facilities (of more than 30 MW generating capacity) to be constructed,[24] 38 plants (totaling 14.1 GW) are still in the project phase. The average production cost of these plants is officially estimated at US$43/MWh. Although this may be an underestimate (the average production cost of those plants that are currently under construction is US$75.7/MWh),[25] even under the current cost assumptions, the potential for natural gas in those plants for

[23] Investment cost, US$850/kW; capacity factor, 70 percent; O&M expenses, US$30/kW/yr.; fuel cost, US$2.70/mmbtu; real discount rate, 12 percent; lifetime, 20 years.

[24] Considered to be the minimum size of a combined-cycle power plant.

[25] The inconsistency between the two figures has a twofold explanation: (a) the plants currently under construction were, for the most part, initiated in the late 1970s and 1980s and are suffering long construction delays caused by the financial crisis afflicting power utilities and (b) cost estimates of projected plants are regularly underestimated by the power utilities in order to get power projects approved by Eletrobras.

which the production cost would exceed US$46.1/MWh is 5.4 GW; this corresponds to a potential gas consumption of 21 mmcmd (742 mmcfd). The potential would most probably be even higher if the comparison of the various alternatives were to be made on the cost of delivering power at the city gate, rather than at the outlet of the production plant (owing to higher power transmission costs from hydro sites).

9.20 A detailed survey of the potential market for natural gas specifying the location, capacity and gas consumption of potential gas-fired power plants would require a complete least analysis of both the production and transmission facilities of the SSM system (which is beyond the scope of this study). Among various alternatives, and given the projected needs for power generation in the State of São Paulo,[26] the most likely option is that in the medium term the SSM system could absorb an additional gas-based power capacity amounting to 1,290 MW during 1997-98 plus 1,200 MW during 2000-2001. The first 1,290 MW would consist of (a) repowering the single-stage turbines (2 x 100 MW) of Eletropaulo's Piratininga oil-fired plant, located in the Greater São Paulo area and currently underutilized, into a 600 MW combined-cycle power plant; (b) repowering CPFL's 2 x 15 MW Carioba plant, located near Campinas, into a 90 MW CC power plant; and (c) adding a new 600 MW CC plant on the Piratininga site. The second step (1,200 MW) would consist of two new 600 MW CC plants to be constructed along the route of the future pipeline. Gas consumption in these stations would reach 2.7 mmcmd in 1997, 5 mmcmd in 1998, 9.4 mmcmd in 2000, and 9.7 mmcmd from 2001 on (95, 177, 332, and 343 mmcfd, respectively).

Residential and Commercial Sector

9.21 Comgas now supplies medium BTU town gas (4,750 kcal/cm) derived from naphtha cracking to 219,000 residential and 4,900 commercial customers. In addition, the gas utility has started distributing natural gas to a limited number of residential and commercial customers (about 4,800), generally located near industrial areas, using natural gas-dedicated steel pipelines. Owing to climatic conditions, gas is mainly used for cooking and, to a lesser extent, for water-heating; the per-unit consumption is relatively low at 1.16 cmd (41 cfd) and 34.8 cmd (1.3 mcfd) for residential and commercial customers, respectively. Considering the size of the conurbation (about 11 million inhabitants) and the relative wealth of the city, the potential residential and commercial market most probably exceeds the objectives set by Comgas within the São Paulo Gas Distribution project (see paragraph. 9.8).[27] This upside potential can be met if additional gas quantities were made available. Natural gas would replace various fuels, including LPG and town gas (for cooking) and electricity (mainly

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26 Based on data provided by the CESP Planning Department.

27 A recent market survey performed by Comgas shows that there are 910,000 residential and commercial potential consumers (including already supplied consumers) within the town gas area, of which 393,000 in total (43 percent) will be connected when the SPGD project is completed. By way of comparison, in less populated Rio de Janeiro, the state-owned gas utility CEG now supplies 525,000 residential consumers.

for water heating). It was assumed that once Bolivian gas is available, new residential and commercial customers would be connected at an annual growth rate of 5 percent during the initial years of operation, followed by a lower growth rate beyond 2001, and that the per-unit consumption would increase owing to a more diffused use of gas for water-heating. The demand that could be met by Bolivian gas would then reach 0.7 mmcmd (25 mmcfd) in 2000 and 1.1 mmcmd (39 mmcfd) in 2010.

Compressed Natural Gas

9.22 The State of São Paulo has recently passed a regulation requiring that taxis and mass transit buses be converted to natural gas in order to decrease the level of air pollution. There are currently 22,200 taxis and 8,250 buses in daily operation in the greater São Paulo area. Taxis run mostly on ethanol, and buses use exclusively diesel oil. They currently consume over 2 mmcmd of natural gas equivalent, 55 percent of which is ethanol, and 42 percent diesel oil, the remainder (3 percent) being gasoline. Considering that for economic reasons such a regulation is generally difficult to enforce to its full extent, it was assumed that 30 percent of the taxis and 50 percent of the buses would run on natural gas in 2010. The resulting gas consumption would reach 0.9 mmcmd in 2000, 1.2 mmcmd in 2005, and 1.4 mmcmd (32, 42, and 49 mmcfd, respectively) in 2010. This expansion of the market will require setting comprehensive pricing and regulatory measures.

Projected Overall Gas Consumption

9.23 To assess potential gas demand in São Paulo, it is assumed that the construction of the pipeline from Bolivia will be completed by the end of 1996 and that the first year of operation will be 1997.[28] The consumption forecasts cover the medium-long-term, that is, until 2010. A five-year buildup period covers the years 1997-2001, during which most of the existing market is converted.[29] Beyond 2001, the consumption increase is mostly owing to the natural increase of the potential market, linked with the growth of the economy and of the population. In the first year of operation (1997), natural gas consumption amounts to 5.5 mmcmd (194 mmcfd); half of this comes from the conversion of the two power plants, and one third comes from the industrial sector. The 8 mmcmd (283 mmcfd) level is reached in Year 2 (1998), and the 16 mmcmd (565 mmcfd) level is reached by the end of Year 4 (2000), owing to the coming on stream of the first set of the new combined-cycle power plant. At the end of the buildup period (2001), consumption exceeds 20 mmcmd (706 mmcfd) and in 2010 reaches 25.7 mmcmd (908 mmcfd). In cumulative terms, the São Paulo market will have consumed 23.5 bcm (0.83 tcf) of Bolivian gas at the end of the buildup period, essentially for power generation (46.5 percent) and for thermal uses in the industrial sector, including cogeneration (44

[28] Delays are expected.

[29] The existing market is defined as the potential consumers who already exist and operate when natural gas becomes available.

percent), the remainder being distributed into CNG (5 percent) and the residential and commercial sector (4.5 percent).

Table 9.3 Projections of Natural Gas Consumption in the State of São Paulo, 1997-2010 (mcmd)

Sector	*1997*	*2000*	*2005*	*2010*
Industry	1,876	6,914	10,167	12,006
Cogeneration	217	800	1,176	1,389
Power generation	2,690	5,029	9,706	9,706
Residential and commercial	406	669	903	1,137
CNG	268	910	1,178	1,446
TOTAL	**5,457**	**14,322**	**23,130**	**25,685**

Source: Mission estimates.

9.24 ***Economic and financial values.*** Natural gas has no captive market in Brazil, with the probable exception of the production of ammonia and some petrochemicals for which gas is already being used. Gas will thus have to compete on every market with other available energy sources. The market value of natural gas is thus directly related to the cost of the competing energy sources. The market value represents the maximum price that potential consumers would be willing to pay in order to substitute natural gas for the fuel that they are currently using; thus, switching to gas does not mean any loss or gain. In a given potential market, the market value is equal to the cost to the end-user of the competing energy, minus specific gas-related costs (for example, the cost of converting the equipment to gas), plus specific gas-related benefits (for example, the savings that gas is likely to bring in the operation of the factory, known as the natural gas "premium"). Both economic and financial market values have been computed and are presented below. Economic value makes reference to the economic cost of a competing energy source, that is, the cost at which a competing energy source would be available to the end user in a competitive environment, without being distorted by taxes or subsidies. The concept of economic value thus enables one to compare various energy alternatives, from a macroeconomic viewpoint, at the global level of the country. Financial value makes reference to the current selling price of the energy source on the market, including existing taxes or subsidies, as set by the government. This concept must be considered in any financial, microeconomic analysis; in this chapter, however, financial values are given without sales tax.

9.25 ***Values at burner-tip and city gate.*** Most energy sources, in particular oil products and coal, are delivered and billed at the user's gate. Thus, the value of natural gas should be the cost of the competing energy sources at the user's gate. This is appropriate when two energies are competing in a "new" market, that is, when the potential facility is not yet built, because in a new thermal equipment has to be built anyway. In São Paulo, however, especially during the buildup period, gas will have to compete mostly in the existing market, that is, gas will have to substitute for fuels currently used in operating facilities. For the potential gas consumer, any interfuel

substitutions will generate additional costs beyond the user's gate, in its own premises, including metering and regulating stations, natural gas piping, conversion of the equipment, and regulation. The market value of gas at the user's gate is thus equal to the cost of the competing energy source at the user's gate, minus the cost of bringing gas from the user's gate to the burner-tip. To substitute gas for fuel, the gas value must be equal to, or higher than, the actual gas supply cost. Natural gas has to bear the cost of the network from the city-gate station (that is, the point where gas is transferred by the transmission company to the distribution company) to the user's gate. This component is generally a significant part of the total delivery cost of gas to the consumer, and is generally higher than the cost of trucking liquid fuels from a city storage to the consumer. In this chapter, the costs and values of the competing energy sources in the existing markets are computed at the final level, that is, the user's gate, because these energy sources are delivered and billed at the user's gate. As far as natural gas is concerned, costs and values are computed at the burner-tip and city-gate levels.

Industrial Sector

9.26 Natural gas netback values have been computed for each fuel used in the sector. The economic cost of the oil products is based on Caribbean prices FOB linked to a crude price of US$20/bl. Variation of the economic cost in relation to the variation of the price of crude oil is given in the sensitivity analysis discussed below. Downstream costs, that is, from ocean freight and insurance cost through distribution margin, have been established on the basis of the previously mentioned World Bank study (Table 9.4).[30] Because Brazil is, and will remain, globally a net oil importer, import parity has been considered for all oil products, including fuel oil. Even if temporary fuel oil surplus exists when natural gas expands in the São Paulo area, excess supply will soon be absorbed by the normal growth of the economy in other areas where gas is unavailable, transformed into lighter products that will be in short supply in Brazil, or both.

[30] Brazil: Energy Pricing and Investment Study, February 1992.

Table 9.4 Economic Cost and Market Value of Oil Products in the São Paulo Area (based on crude oil @ US$20/bl)

Cost/value item	*Unit*	*HSFO*	*LSFO*	*Diesel*	*LPG*
Price of product, FOB Caribbean	$/bl	11.50	13.50	24.70	8.80
Price of product, FOB Caribbean	$/ton	77.05	90.45	182.78	100.26
Ocean freight, insurance, port charges	$/ton	14.87	14.87	28.49	41.25
Inland transportation and storage	$/ton	17.09	17.09	29.90	31.69
Distribution cost	$/ton	8.24	8.24	15.32	106.48
Economic cost at end user	$/ton	117.25	130.65	256.48	279.60
Economic cost at end-user	$/mmBtu	**2.99**	**3.17**	**6.04**	**6.03**
LHV/HHV differential		0.95	0.95	0.95	1.00
Natural gas premium		1.03	1.03	1.03	1.00
NG market value at burner-tip	$/mmBtu	**2.93**	**3.10**	**5.91**	**6.03**
Cost of conversion (average)	$/mmBtu	0.15	0.15	0.15	0.03
Cost of distribution (average)	$/mmBtu	0.48	0.48	0.48	0.48
NG netback value at city gate	$/mmBtu	**2.30**	**2.47**	**5.28**	**5.52**

Source: Mission estimates based on previous World Bank report.

9.27 The economic cost of the domestically produced energy sources, including electricity, is considered equal to its long-run marginal cost. The weighted average economic cost of the various energy sources consumed in the industrial sector was computed, based on the basket of the fuels that are likely to be substituted for by natural gas at the end of the buildup period. With 54 percent of the current market, fuel oil is by far the most widely used competitor. The economic cost of fuel oil ranges from US$2.99 to US$3.17/mmBtu at the end user, depending on the sulfur content. The costs of distribution and conversion are computed at US$0.48/mmBtu and US$0.15/mmBtu, respectively,[31] so that the weighted average economic cost of both fuel oil qualities at the city gate stands at US$2.45/mmBtu. The economic value is even lower (US$2.39/mmBtu), when LHV/HHV adjustment and efficiency ratios are considered (the LHV/HHV ratio is lower for gaseous fuels than for liquid fuels [-5 percent], and the ratio is not fully compensated by the higher efficiency of natural gas [considered 3 percent] at the burner).[32] Although fuel oil can be substituted more easily, in the longer term, natural gas is likely to replace energy sources such as electricity and wood. Because the economic cost of these energy sources is much higher than for oil products, the weighted average economic cost of the global basket of fuels is significantly drawn upward.

9.28 A policy of the Brazilian government has been to contain energy prices in the belief that inflation would then be curbed. Thus, the selling price of some energy

[31] Based on figures from the São Paulo Gas Distribution project.

[32] LHV/HHV ratios are 0.90 and 0.95 for gaseous fuels and liquid fuels, respectively; thus, the differential is close to 0.95; gas burner efficiency is considered 3 percent higher than for liquid fuels burner (0.80 versus 0.77).

sources does not reflect real economic cost. Although this phenomenon is even more common with regard to energy used in the residential sector, some industrial energy prices, in particular, electricity, may be widely distorted. With the exception of overpriced LPG, oil products (especially fuel oil and diesel oil) are generally sold at prices close to their economic cost. Conversely, electricity is sold to the medium and large industry (more than 30 kV) at 64 percent and 78 percent of the marginal cost, respectively. Wood and charcoal are also heavily underpriced at 59 percent and 73 percent of their economic cost, respectively. These distortions lead to average financial costs that are significantly lower than economic values when electricity and wood are included in the basket of fuels. The financial value of fuel oil (US$3.04/mmBtu at end user) is very close to its economic value (US$3.01/mmBtu at end user), which corresponds to netback values of natural gas at the city gate of US$2.41/mmBtu (financial) and US$2.38/mmBtu (economic), respectively. The weighted average financial value of the global basket of fuels stands at US$3.63/mmBtu at end user, however, corresponding to US$3.00/mmBtu at the city gate (see Table 9.5).

9.29 Depending on which fuels are considered substitutable by natural gas and on whether economic or financial values are contemplated, the value of natural gas in São Paulo may vary significantly. Table 9.5 presents a set of sensitivity analyses that show how the value of the gas at the city gate varies when various market and prices conditions are considered. The various scenarios are characterized as follows:

- ***Scenario A.*** This scenario is conservative, assumes that fuel oil consumers (both high and low sulfur) are the only likely market for natural gas and that fuel oil is sold at its economic cost. The economic value of gas is slightly below the economic cost of the basket of the two qualities of fuel oil. Although this market environment is likely in the beginning because liquid products are easier and cheaper to substitute, fuel oil is not the only substitutable fuel in the longer term. In addition, the size of the fuel oil market is insufficient to absorb the gas quantities that will be available, unless power generation takes the larger part of the gas exported.
- ***Scenario B.*** This considers other oil products in addition to fuel oil, that is, diesel oil and LPG. Owing to the limited market of these fuels in the industrial sector, the variation of the value of gas is moderate, although the economic cost of both fuels is significantly higher than for fuel oil.
- ***Scenario C.*** This assumes that natural gas competes with all energy sources, including high-cost electricity and wood. Because economic cost of the other energy sources is higher than the cost of fuel oil, the weighted average value is drawn upward. This market pattern is expected in the medium term, after the gas seller has skimmed the easier market consisting of oil products. The value obtained in this scenario is of a mature market,[33] when those potential consumers

[33] The industrial market should plateau in 5 years; that is, in the medium term.

that currently use electricity, wood, or charcoal are ready to consider the comparatively higher cost of shifting to natural gas. Experience in mature gas markets shows that industrialists are reluctant to replace equipment before it is fully depreciated or obsolete, even when such an operation is globally profitable, so that replacing solid fuels and electricity takes longer than substituting gas for liquid fuels.

- *Scenario D.* This assumes that on more difficult markets, for example, electricity and solid fuels, the potential consumers will have to bear additional costs of conversion and possibly undergo alterations in their industrial process thus requiring incentives to shift to gas. It is thus considered that the real value of the gas is much lower than the economic cost of the competing energy sources; tentatively, the value of gas is estimated at 80 percent of the economic cost of solid fuels and 50 percent of the economic cost of electricity. This scenario fits the situation whereby accelerated penetration of gas on difficult markets is associated to commercial incentives sought by the gas seller.

Table 9.5 Variation of the Market Value of Natural Gas at the City Gate in the Industrial Sector, According to Four Scenarios (US$/mmBtu)

	Scenario	*Value of gas*	
		Economic	*Financial*
A.	Gas versus fuel oil only	2.38	2.41
B.	Gas versus oil products only	2.54	2.63
C.	Gas versus all energy sources	3.29	3.00
D.	Gas versus all energy sources, with commercial incentives	2.70	2.52

Source: *Mission estimates.*

Other Sectors

9.30 ***Power generation.*** As previously mentioned (paragraph 9.19), the officially estimated costs of power generation probably do not reflect the actual costs. The average cost of power generation from new plants (both hydro and thermal) expected to enter into operation in the SSM interconnected system during the 10-year expansion plan (1991- 2001) is US$49.90/MWh, As a comparison, the average long-run marginal cost (LRMC) for the southeast-midwest region was computed in September 1989, by DNAEE at US$75.53/MWh, and the LRMC for the largest consumer category (consumers with tariff A1, over 230 kV) at US$48.37/MWh. Based on the official figure, the market value of natural gate at the user's gate is US$3.07/mmBtu for the whole scheme planned for Piratininga (repowering of the oil-fired power plant and new combined-cycle power plant).[34]

[34] Average investment cost, US$700/kW; implementation schedule, 4 years; production plateau reached on year 5. Discount rate, 12 percent; O&M expenses, US$5/MWh; efficiency, 45 percent on LHV; lifetime, 20 years.

9.31 ***Residential and commercial sector.*** The market value at the end user for the residential and commercial sector is high for each subsector at US$15.53 and US$12.14/mmBtu, respectively. These figures are based on those fuels that will be substituted for by natural gas, including LPG, town gas, and low-voltage electricity. Moreover, these figures are high owing to the high cost of these fuels. The conversion costs (replacement of the former appliances, carcassing of the buildings, and metering and regulating devices) are estimated at US$5.69/mmBtu for residential consumers and US$1.35/mmBtu for commercial consumers. Distribution costs are estimated at US$3.00/mmBtu for the residential subsector and US$2.20/mmBtu for the commercial subsector. Based on the above figures, the netback values at the city gate are US$6.84 and US$8.59/mmBtu for the residential and commercial subsectors, respectively.

9.32 *CNG.* Based on the economic costs of ethanol and diesel oil and the fuel mix consumed by taxis and buses, the average netback value of natural gas at the burner tip is US$7.34/mmBtu. The netback value at the city gate is US$6.07/mmBtu—that is, considering the costs of engine conversion, filling stations (US$0.87/mmBtu), and distribution (assumed to be equal to the cost for the industrial consumers, that is, US$0.48/mmBtu).

From Market Analysis to Sales Negotiations

9.33 Gas export contracts link together sellers and buyers, often for several decades. It is crucial for the viability of such a contract that both parties and also third parties along the delivery chain remain satisfied with the contract over its lifetime. The best way to safeguard this objective is to link the gas price at the point of delivery to the value of gas at the end-user level. A price formula should be thus calculated to reflect the price developments of the alternative fuels available to the customers. In a market in which prices are set by free competition, one would establish a price and a price formula that would fit the market at (or close to) the time of negotiations. Prior to the start-up of gas deliveries, the parties would check the suitability of the price level created by the formula, and if necessary, adjust the price to take account of any specific development in the market. With a market in which end-user prices are distorted and under government control, it may not be possible for the gas buyer (the importer) to accept a price level that is based on a yet nonexistent free end-user market. Under such circumstances, pricing solutions with weaker links to the market may be acceptable for an interim period, allowing later adjustments to an emerging free market to be made by a price revision clause in the contract. The price link to market values is the best way to keep the gas buyer profitable and able to meet his contractual obligations. When the gas price is not linked to freely priced alternative fuels, the question of financial solidity of the buyer becomes even more important. In markets with many gas suppliers and abundant availability of gas, gas prices may be established on the basis of gas-to-gas competition.

9.34 Even if gas export prices are based on the competitively set prices of competing fuels, the market value, as estimated above, will never be achieved fully. First, in building new markets for natural gas, some clear price incentives must be provided for

consumers to convert rapidly to natural gas. Second, gas marketing companies are usually not allowed or able to charge the full value to all customers. Whereby gas tariffs are often set on a nondiscriminatory basis related to yearly volume and offtake flexibility requirements, part of the value is lost to the gas company. This loss may be in the range of 5 to 20 percent of the full value, depending on local circumstances and the marketing efficiency of the gas distributor. In the case of São Paulo, in particular, the price of natural gas to industrial users will probably have to be set at about the fuel-oil level for some time; therefore, the higher values found in the electricity or LPG substitution markets may not be captured.

Bolivia - Brazil Gas Export

9.35 In November 1991, Bolivia (represented by MEH and YPFB) and Brazil (represented by Petrobras) signed a memorandum of understanding to work toward a project to import 8 mmcmd (283 mmcfd), rising to 16 mmcmd (565 mmcfd) of Bolivian gas, mainly for the São Paulo market. Subsequent joint technical studies and agreements have advanced this project to the feasibility-study stage. Work is proceeding on this study, but it is premature to reach conclusions regarding the economic attractiveness of the scheme.

9.36 Petrobras has worked closely with YPFB to assess the Bolivian reserve base that could supply the export pipeline. It is on the basis of these studies that the Bolivian and Brazilian governments have agreed to a gas-flow buildup profile for the pipeline. Petrobras is currently negotiating with YPFB and major international petroleum companies for the exploration and development of several fields in Bolivia, particularly in the sub-Andean and adjacent structures where there are good prospects for additional reserves.

9.37 Nonetheless, from the Bolivian perspective, a number of important issues must be addressed to bring the scheme to reality. Perhaps, foremost among these is the need to increase Bolivia's proven gas reserves through further exploration. An approximate calculation of the reserves that Bolivia would require to meet domestic and export demands, including requirements of the proposed 20-year sales contract with Brazil, shows that Bolivia would have to place a high priority on the discovery of additional reserves. This can be seen from the Table 9.6, which postulates an export scheme to Brazil of 8 mmcmd rising to 16 mmcmd within 7 years. This table assumes that for the project to be deemed viable, Bolivia must have sufficient reserves to generate a 5-year supply of gas at the end of the initial contract period (assumed to be 2016)—that is, for supplies to last to year 2021.[35] As can be seen in Table 9.6, there is a shortfall of 2.7 tcf based on proven reserves and 0.3 tcf based on proven plus probable reserves. While these figures may seem somewhat conservative, they reflect the fact that financiers

[35] Gas reservoirs can produce at most 10 percent of their reserves each year, and sometimes less if liquids recovery is not to be compromised. A random distribution of gas fields is considered, that is, average remaining lifetime of gas fields in 2016 is estimated to be 5 years.

of gas projects (such as commercial banks) normally require substantial reserves security (proven reserves well in excess of contractual deliveries).

Table 9.6 Bolivian Reserves versus Market Requirements (bcf)

Reserves available	
Proven	4,108
Probable	2,334
Proven plus probable	**6,442**
Reserves required	
Domestic demand to 2016	1,268
15-year supply from 2017	1,040
Exports to Argentina to 1996	393
Exports to Brazil 1997 to 2016	3,729
15-year supply from 2017	3,094
Total requirements	**9,523**
Reserves to be discovered	
Versus proven	(5,415)
Versus proven plus probable	(3,018)

Note: Based on the characteristics of the current agreement between Bolivia and Brazil, that is, 20 years of consumption; first year (1997), 8 mmcmd; plateau, 16 mmcmd; build-up, 7 years.
Source: Mission estimates.

9.38 The need to increase proven reserves as the gas export project proceeds leads to some strategic conclusions: First, it is important that any gas export project be linked to a comprehensive project to appraise Bolivia's reserves (converting probable to proven reserves) and to discover new reserves. This project must involve opening all prospective Bolivian areas to foreign investment. Given Bolivia's prospectivity, a suitably designed exploration program stands an excellent chance of discovering the additional reserves required. Second, to increase the confidence of buyers in early years, it may be worth investigating the option of including some reserves from northern Argentina in the export scheme, using the existing Bolivia-Argentina pipeline.

9.39 From the Bolivian perspective, another significant issue is the apportionment of the risks of the project between Bolivia and Brazil.[36] There is clearly the possibility of some bargaining inequality in contract negotiations, because Brazil is effectively negotiating for an alternative fuel to existing supplies and can afford to wait for Bolivian gas supplies if these are not provided on sufficiently attractive terms. On the other hand, Bolivia has no alternative large market for its gas in the foreseeable future. Bolivia may thus have more to lose by delays in the project than Brazil. Moreover, for

[36] Comments about negotiations were written before signing of the exports contract with Brazil. They do not indicate any judgment by ESMAP on the final outcome of the negotiations.

Brazil, the economic benefits of Bolivian supply are modest within the overall context of the economy; whereas for Bolivia, the export revenues from the project are critical to economic development. Therefore, Bolivia could expose its economy to significant risks in the event of project failure or adverse price or market developments.

9.40 In negotiating the gas supply and price contract, Bolivia will have to be cautious not to assume too much of the project risk in exchange for an early Brazilian commitment to take its gas. In the case of supply risk, Bolivia must be wary of committing supplies that are not proven, because the economic consequences of having to compensate Brazil, should adequate reserves not be found, would be serious. Bolivia must also be wary of taking on excessive price risk, especially because Bolivia's objective for this project (predictable export revenues as well as increasing liquids reserves) is different from that of Brazil (fuel substitution on attractive terms) and linkage of the city gate price to oil prices with a large, fixed transmission charge runs the risk of generating extreme volatility of wellhead prices in Bolivia. All these issues should be addressed through careful design of the sales and other contracts. During negotiations, the Bolivian authorities should seek to benefit from the experience of similar projects elsewhere by obtaining advice from suitable advisors.

9.41 In addition, there are many structural and institutional issues to be addressed within Brazil. In particular, the roles of Petrobras, the state distribution companies, and the private sector remain to be clarified. These matters lie outside the scope of this report, but will require close attention as the export project develops.

10

Exports to Chile

10.1 The North of Chile has long been viewed as a possible market for Bolivia's gas. From a strategic point of view, the development of an additional market to Argentina and Brazil has attractions. First, it provides a potential outlet for gas in the event that exports to these other markets fall short of expectations. Second, it increases potential competition for Bolivian gas resources and, hence, Bolivia's bargaining power. Finally, it provides an additional potential market for future gas discoveries that cannot be absorbed by other markets.

10.2 Chile's own natural gas resources are relatively modest and are concentrated in the South, too far from potential markets in the Center and North to be a viable source of supply. Moreover, Chile's domestic energy resources—hydroelectricity, wood, and coal—are concentrated in the Center and South, leaving the North dependent on long-distance transport of energy for its requirements.

10.3 The North of Chile bordering Bolivia, a sparsely populated desert region, is one of the main copper mining areas of the world. It is the large energy needs of the copper mining industry, together with the demand from some smaller mining and processing of other minerals, that makes the region an area of potential interest for Bolivia's gas exports.

10.4 The possibility of exporting Bolivian gas to Chile was studied by consultants to the Bolivian government during 1990, and was discussed at the government level during early 1991. No substantial agreement was reached at the time, however. More recently, studies were undertaken by Spanish and Italian pipeline contractors, who also examined the possibility of exporting gas from northern Argentina.

Key Issues

10.5 A number of issues must be addressed in assessing the appropriate strategy for Bolivia in relation to the export of natural gas to Chile:

a. *Size of market.* Although there are substantial uncertainties about the growth of demand in the future, the scale of the accessible energy market in the North is

relatively easily determined, given the concentration of demand in a few mining and power generation centers.

b. ***Competition from other fuels.*** The real cost of alternative fuels must be determined. It is a relatively straightforward task in the case of internationally traded fuels—for example, oil products, and high-calorific-value coal. It is a more difficult task, however, in the case of fuels more specific to the regional market—particularly low-calorific-value coal.

c. ***Political and commercial issues.*** As with all gas trade projects, the buyer must take into account the political context as well as commercial and supply security considerations.

10.6 These issues are addressed below. The conclusions suggest that the potential market in northern Chile is both limited relative to Bolivia's exportable surplus, and is unlikely to be accessible at an acceptable netback to the wellhead in Bolivia.

Energy Demand in the North of Chile

10.7 Energy demand in the North of Chile can be analyzed within three principal sectors (a) the power sector, which can be separated into that dedicated to copper mining and that for general consumption; (b) industrial use in the mining sector; and (c) other use in industry and in the residential and commercial sectors. It is assumed that the transport sector is insusceptible to substitution by CNG (the environmental imperatives that encourage such substitution in the Santiago area are not present in the North).

10.8 For the purpose of a gas pipeline from Bolivia, only the demand in the region around Antofagasta is considered. The most viable pipeline route from Bolivia starts around Tarija in Southern Bolivia and follows the line of an existing railroad to Antofagasta. The two major towns lying further north in Chile—Iquique and Arica—are respectively about 350 km and 600 km north of Antofagasta. There are also various mining enterprises, of a modest scale, between these two towns. The region around these towns could add 0.7 mmcmd (25 mmcfd) (20 percent) to total substitutable demand. This is unlikely to justify a dedicated pipeline to the north of Antofagasta, however.

Power Supply

10.9 Power supply in the North of Chile is coordinated through the Sistema Interconectado del Norte Grande (SING). The main utility generator for the North, EDELNOR, and the major generation center of the national copper company, CODELCO, in Tocopilla supply this system. About 50 percent of EDELNOR's supplies go to the mining industry. The Tocopilla center also provides power to CODELCO's large mine at Chuquicamata. Demand for power is expected to grow, as shown in Table 10.1.

Table 10.1 Estimated Demand for Power in the Northern Region 1991-2000, (MW)

Demand source	*1992*	*1995*	*2000*
Utilities	474	520	606
Mining	2,289	3,415	3,789
of which Chuquicamata	(1,875)	(2,221)	(2,603)
TOTAL	**2,763**	**3,935**	**4,395**

Source: Mission estimates.

10.10 As can be seen, Chuquicamata dominates the overall power demand in the region. Likewise, CODELCO's generation in Tocopilla dominates power supply—the capacity of Tocopilla is 562 MW compared with EDELNOR's 93 MW. The distribution of capacity is shown in Table 10.2.

Table 10.2 Power Generation Capacity in the Northern Region

EDELNOR		*CODELCO*	
Hydro	12.8 MW	Coal	400 MW
Diesel sets (fuel oil)	22.5 MW	Fuel oil	122 MW
Diesel sets (diesel oil)	36.5 MW	Turbines (diesel)	40 MW
Turbines (diesel oil)	20.8 MW		
TOTAL	**92.6 MW**		**562 MW**

Source: EDELNOR.

10.11 Future EDELNOR plans call for the addition of 40 MW to 80 MW of diesel units (fuel-oil-based) in 1994 and 125 MW of coal power capacity in 1996. CODELCO Tocopilla will also install about an additional 125 MW of coal power by 1995 to cope with rising demand from both Chuquicamata and EDELNOR.

Mining Industry Demand

10.12 Direct demand for fuel in the mining sector falls under two headings (a) that required for smelting and other processing tasks and (b) that required for auto generation (for those mines not obtaining electricity from EDELNOR or CODELCO). The former processes are generally fired by fuel oil, whereas the latter are generally supplied through diesel sets using diesel or fuel oil. The majority of the potential demand for industrial use lies in the Chuquicamata mine and processing complex. Fuel oil demand in Chuquicamata for smelting, heating, and drying amounts to about 0.35 mmcmd (12 mmcfd) of natural gas equivalent. The other mines (copper and other minerals) consume a total equivalent of about 0.17 mmcmd (6 mmcfd). The total equivalent of diesel generation from all sources is about 0.38 mmcmd (13 mmcfd). These figures are unlikely to increase significantly before the year 2000 because nearly all major new mining projects are likely to purchase their power from the grid, and few new industrial projects are planned.

Other Industries and Residential and Commercial Sectors

10.13 Given the limited population and economic activity of the northern region, demand from other industrial and residential sectors is likely to be modest at best. The industrial sector as a whole is estimated to consume about 0.2 mmcmd (7 mmcfd) of gas equivalent, about 50 percent as fuel oil and 50 percent as coal. The residential and commercial sector presents few opportunities—the total LPG demand in Antofagasta, the major conurbation, is about 9,500 tons/year, equivalent to only 0.03 mmcmd (1 mmcfd).

10.14 In summary, from a technical point of view, the total oil product and coal demand that could be replaced by natural gas, albeit with widely varying conversion costs, is as shown in Table 10.3.

Table 10.3 Total Technically Substitutable Fuel Demand, 1992-2000 (mmcmd NG equivalent)

	1992	*1995*	*2000*
Power			
EDELNOR and CODELCO	2.01	2.90	3.38
Other autogenerators	0.38	0.36	0.36
Mining industrial	0.52	0.53	0.53
Other industries & residential/ commercial	0.20	0.20	0.20
TOTAL	**3.15**	**3.99**	**4.47**

Source: Mission estimates.

Competition with Other Fuels

10.15 Natural gas from Bolivia would compete with several fuels in the North of Chile, principally coal (in power generation) and fuel oil (in power generation and the mining industry). In this regard, it is worth noting the prevailing energy price policy in Chile, which seeks to reflect the economic value of fuels in market prices and is based, to a large extent, on competitive fuel markets. Hence, there is no significant divergence between the economic and financial costs of energy faced by Bolivian gas in the Chilean market.

Coal

10.16 Coal consumption, principally in Tocopilla, accounts for about two-thirds of the substitutable energy consumption in the North of Chile. Hence, the price at which coal can be displaced is key to the value of Bolivian gas in the Chilean market.

10.17 Chile supplied some 58 percent of its total coal requirements of 4.1 million tons (at 6,350 kcal/kg equivalent) in 1990. Coal is produced in two principal areas: (a) the Arauco region in the south-central area of the country, accounting for 70 percent of national supplies, which produces a coal with a high calorific value, and (b) the

Magallanes region in the extreme South, which produces a subbituminous quality coal. The Tocopilla plant accounts for a substantial proportion of national production, taking 1.06 million tons (30 percent of production's) in 1991. About 70 percent (calorific equivalent) of Tocopilla's consumption is of Magallanes coal, which has been produced at the Pecket mine since 1987. This coal was developed specifically for the Tocopilla power station, along with dedicated loading facilities and ships. In turn, the Tocopilla power station is specifically adapted to the consumption of Magallanes-quality coal. Magallanes coal is sold to Tocopilla under a 10-year contract to 1997 that provides for 880,000 tons per year. The price under this contract is about US$54/ton (6,450 kcal/kg equivalent), that is, US$2.11/mmBtu. It is safe to assume, given the sunk cost in the mine, that the cost of production, is well below this price. Cost figures available for the mine in the early 1980s indicate that average production costs are probably about US$33/ton (delivered Tocopilla) although operating costs are probably as low as US$17/ton. On this basis, Bolivian natural gas would have to sell at only US$1.3/mmBtu to compete with the average cost of Magallanes coal, and at only US$0.7/mmBtu to compete with its variable cost. In addition, conversion of dedicated Tocopilla coal boilers to burn natural gas would result in a derating of at least 10 percent according to CODELCO.

10.18 The Arauco coal burned at Tocopilla is, in fact, noncompetitive with imported coal, the latter priced at US$45/ton CIF, and the former having a long-run marginal cost of some US$57/ton. Accordingly, plans are under way to rationalize the production of coal in the Arauco region. To compete with imported coal, Bolivian gas would have to sell at about US$1.75/mmBtu.

10.19 Substitution of coal with natural gas does, of course, produce substantial environmental benefits in terms of emissions of particulates and of gases such as sulfur dioxide and carbon dioxide. However, the Tocopilla plant is relatively well-equipped with environmental control devices (dust is captured through electrostatic precipitators), and the isolated location of the plant reduces the local environmental impact. Thus, the switch to gas is unlikely to be undertaken on environmental grounds alone.

Fuel Oil

10.20 The wholesale price of fuel oil delivered to the port of Tocopilla in June 1992 was US$104/ton. The final price to users such as the copper mines would be somewhat higher, although the large volumes transported would result in relatively low distribution costs. Because the wholesale price was equivalent to US$2.60/mmBtu, the final price at which Bolivian gas would be attractive to users of fuel oil would be about US$3.00/mmBtu. However, it should be noted that substitution is likely to be restricted to industrial use of fuel oil—the conversion of diesel power sets using fuel oil to natural gas is likely to be too expensive unless natural gas was priced well below fuel oil. Similarly, it can be assumed that none of the diesel sets using diesel oil will convert to natural gas.

10.21 In principle, a new station such as the 125 MW station planned by EDELNOR and CODELCO for the 1990s could be fired with gas instead of coal by using

a combined-cycle station. It is unlikely that Bolivian gas could compete with the variable cost of Magallanes coal, but even at the average cost of coal, the equivalent value of gas in a combined-cycle station would be more than US$3.00/mmBtu. Because production of Magallanes coal can be expanded substantially at a modest cost, Bolivian gas prices would unlikely be above this figure. A combined-cycle station would have no alternative low-cost fuel (the only alternative being diesel), and it is possible that such a station, based on imported gas, would not be considered by the Chilean authorities in the context of a strategic industry such as copper. The possibility of such demand must thus be considered speculative, and should be included in the demand estimates as a "high case."

Table 10.4 Total Potential Demand (mmcmd) and Competitive Value of Gas, 1995-2000

Demand source	*1995*	*2000*	*Competitive value US$*
Mining			
Industrial	0.52	0.53	$3.00/mmBtu
Autogeneration	0	0	Conversion unviable
Power			
Coal	2.59	2.89	$1.30/mmBtu
Fuel oil	0.24	0.40	$3.00/mmBtu
New power	0	0.50	$3.00/mmBtu

Source: Mission estimates.

10.22 Hence, it can be seen that to capture a substantial market, Bolivian gas would have to be priced as low as US$1.3/mmBtu at Tocopilla to compete with Magallanes coal. It should be noted, in addition, that it will be impossible to substitute most of the Magallanes coal before 1998 owing to the long-term contract between CODELCO and COCAR.

Pipeline Investment Cost

10.23 The total length of the pipeline from the southern Bolivian gas fields to Tocopilla would be 921 km, plus an additional 192 km to Antofagasta. According to a study undertaken by Sofregaz in 1990, the cost of the pipeline (excluding customs duties and taxes) would be US$435 million, [37] assuming that a 12-in. pipe is used for most of the line so as to give a capacity of up to 5 mmcmd (177 mmcfd). Under simple assumptions,[38] approximate transport tariff would be US$1.23/mmBtu for the volumes given above in Table 10.4, assuming a 3 percent annual rate of increase of gas transported beyond 2000. Clearly, such a tariff is incompatible with the requirement to price gas at US$1.30/mmBtu to capture the market for Magallanes coal. Without this market,

[37] Not including the spur line to Antofagasta (US$45 m.).

[38] The assumptions are as follows: 12 percent discount rate; construction, 3 years, operation, 20 years; operating costs, 2 percent of investment.

however, sales volumes would be too low to make the pipeline economic (for example, a 10-in. line with only one half the capacity, because of smaller compression capacity, would still cost US$350 million).

10.24 In this context, the relatively high cost of transport from the Bolivian gas fields to the Pacific coast makes it highly unlikely that any export-based industry could be developed in this location using Bolivian gas. Plans have been considered for methanol and also for LNG plants. However, even with an initial 5 mmcmd through the line, the cost of gas at the coast would be US$1.70/mmBtu, assuming a wellhead cost of only US$0.5/mmBtu. By comparison, gas input costs to LNG and methanol plants in the Middle East are typically about US$0.5/mmBtu.

Additional Considerations

10.25 Two additional factors should be mentioned that impinge on the ability of Bolivia to export natural gas to Chile:

- First, even assuming that Bolivian gas could compete with Chilean coal, strong political and labor objections would arise, given the adverse impact on the trade balance and on employment in Magallanes (where there are few other industries).
- Second, diplomatic relations between Bolivia and Chile have never been entirely normalized since the seizure by Chile of Bolivian territory (and its only access to the sea) in the Pacific War of 1879. Although a gas trade pact between the countries would doubtless contribute to improved relations (which have been gradually growing closer), this factor may impede Chilean willingness to become too dependent on imports of Bolivian gas (especially if a strategic industry such as copper is involved).

Strategic Conclusions

10.26 It is thus apparent that the potential market for Bolivian natural gas in the North of Chile differs from that in both Argentina and Brazil in that in the near future Bolivian gas is unlikely to be able to be sold competitively in this market. In this context, Bolivia's approach to the Chilean market should take into account the following factors:

- Given the scarcity of experienced gas-marketing personnel in Bolivia, it would be inadvisable to devote significant attention to the Chilean market at the expense of that in Brazil or Argentina.
- Bolivia's best hope of profiting from the development of gas in Chile may be through a substantial growth in sales from Argentina to central Chile (in the Santiago area). This increase would divert Argentine gas from competition with Bolivian gas in both the Argentine and Brazilian markets. Hence, Bolivia should encourage regional policies that maximize the use of Argentine gas in Chile (such as regional environmental accords and free trade pacts). Another possibility would be for Bolivia to offer to sell gas to Chile by a swap with an Argentine producer

with a presence in both northern Argentina and the Neuquen. This may increase Chilean confidence in security of supply and improve the utilization of the Argentine transmission system.

- Exploration is now under way in the western Altiplano in Bolivia, although this is in the early stages with no positive results as yet. If substantial hydrocarbons reserves are found in this region, they could provide a nearer source of gas for northern Chile. In particular, the need to dispose of associated gas from an oil and gas discovery could create an imperative to sell gas into northern Chile at a low wellhead price. Such a scenario may represent the best hope for Bolivia to sell natural gas into northern Chile in the foreseeable future.

11

Economic Value, Pricing, and Tariffs

11.1 The pricing of natural gas supply to end-users in Bolivia must take into account two different factors. From the point of view of economic efficiency, it is vital to distinguish between the commodity value of gas as a fuel, which should be determined in relation to market forces within the overall energy market, and the costs of transmission and distribution, which is determined by the investment and operating costs of pipelines. Thus, two separate issues must be considered in determining natural gas prices: First, the price to be placed on gas at the entrance to the transmission system (at the wellhead or ex-gas plant); and second, the tariffs to be charged for transmission and distribution. Currently, gas pricing in Bolivia includes both commodity value and transport costs within a single price, which is not determined in relation to either economic value or costs. This chapter deals with the factors that should be taken into account in setting both the commodity value of gas and appropriate tariffs for gas transport and distribution.

11.2 It is important to emphasize the essentially pragmatic nature of natural gas price-setting. Theoretically based estimates of the economic value of gas should be taken into account in setting the commodity value of gas, yet such estimates are sensitive to assumptions about future reserve discoveries and alternative fuel costs. The method recommended here for determining the commodity value of gas thus takes into account both estimates of the economic value of gas and the realities of the gas industry in a regional context. It is equally the case that the tariffs set for the transmission and distribution of gas, although based on actual costs incurred and principles of economic efficiency, must inevitably deviate from the ideal levels both for reasons of expediency and market imperfections.

Commodity Value of Natural Gas

11.3 Currently, the price of gas in Bolivia is set by MEH. The factors taken into account in setting the price include both historical precedent (a desire not to disrupt the cost pattern of users) and the revenue needs of the government (because much of YPFB's revenues are appropriated directly by the Treasury). In setting the commodity price of gas, however, close attention should be paid both to the economic value of gas and also to the realities of the gas market and overall fuel supply and demand.

11.4 The economic value of natural gas must incorporate two factors: (a) the long-run marginal cost of exploration and production and (b) any depletion allowance that must be associated with the use of natural gas. These factors are considered below.

Cost of Exploration and Production

11.5 The long-run marginal cost of production of natural gas in Bolivia is relatively low. This is explained by the fact that nearly all natural gas is found in association with significant quantities of liquids, and is also rich in LPGs. Hence, most, and frequently all, of the costs of exploration and development can be recouped through the value of liquids production. If the general methodology is to take the joint costs of oil and gas development, and then subtract the value of liquids from the total costs, the remainder that must be covered by the sale price for natural gas is usually very small.[39]

11.6 Several sources indicate a low average incremental cost of exploration and production for natural gas in Bolivia:

a. Figures supplied by YPFB for projects for incremental production totaling about 100 mmcfd from seven fields of various sizes show average incremental costs for natural gas of between US$0.05/mcf and US$0.29/mcf, after allowing for the value of liquids. The weighted average is US$0.24/mcf. These figures do not include the additional values of LPG that could be extracted from the raw gas and represent values ex-gas separation plant.

b. YPFB's 10-Year Exploration and Production Plan shows that the plan can be justified on the basis of the value of liquids production alone. No positive value needs to be ascribed to the gas to yield an acceptable rate of return (over 12 percent) on the overall exploration and production program. The plan may be overoptimistic in relation to its expectations of liquids discovery, based on historical experience in the more mature areas, but even a substantial shortfall in liquids discoveries would not greatly increase the cost of gas.

c. In connection with the Puerto Suarez gas pipeline-power project, YPFB studies suggested an average incremental cost of gas supply at Rio Grande of US$0.28/mcf. This figure was derived from a large-scale model of production and transportation of hydrocarbons in Bolivia. Much of the data used in this model required updating, but it can be assumed to have provided a useful general indication of incremental costs.

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[39] An alternative approach that is sometimes used is to distribute the total costs of oil and gas development between oil and gas according to their calorific values. This approach results in a much higher cost of gas. It is not deemed appropriate here, because oil clearly has a market value that is relatively independent of location, whereas natural gas can be seen as a byproduct with no location independent value. Thus, the only cost that should be attributed to natural gas is that required to sustain the joint development of oil and gas; it is a cost derived from the market value of the liquids.

11.7 Hence, it would seem that a reasonable assumption concerning the average incremental cost of gas in Bolivia at the wellhead is that it is unlikely to be above US$0.25/mcf. Of course, it should be stressed that this does not represent the price that would necessarily induce investors (in particular, private investors) to make exploration and production investments in Bolivia. One important factor affecting this is the assumption about the rate of return in the calculation. The figure used in arriving at these costs, 12 percent after inflation, may be too low to motivate private investors. As discussed below, Bolivia's pricing policy must take into account regional and international factors in attracting capital to its industry; the rate of return to be used for these calculations, thus, should be substantially higher.

11.8 It should be noted that no useful assumptions can be made about the average incremental cost of gas in nontraditional exploration areas such as the Altiplano or the Madre de Dios. This cost will depend entirely on the scale of gas discoveries and their liquids composition. Given the large surplus of gas in the traditional areas, the cost of gas within this area, essentially represented by the cost delivered to Rio Grande, will likely serve as a ceiling to the value of gas from other areas, at least until substantial additional alternative markets can be found.

Depletion Allowance

11.9 The depletion allowance measures the impact of the fact that each unit of a resource consumed today increases the quantity of a substitute that must be purchased at a future date. In the case of gas in Bolivia, a unit of low-cost gas used today brings forward the date when higher cost substitutes, such as fuel oil or hydroelectric power, will have to be used in future.

11.10 To estimate an appropriate depletion allowance, several factors need to be assessed:

- The expected future consumption of natural gas
- The future costs of substitutes to natural gas
- The volumes of reserves, both presently known and potential.

11.11 A range of estimates of the depletion allowance for Bolivia, based on the base-case domestic consumption forecast, is shown in Table 11.1. The key variable introduced is the level of future reserves discoveries (ranging from zero to 5 tcf, which is the quantity discovered over the last 20 years).

11.12 It can be seen that the depletion allowance attributable to 1992 shows a large variation according to the hypothesis adopted, ranging from almost zero to US$0.75/mcf. Moreover, the levelized depletion allowance (which compensates for the fact that in principle, the allowance should increase with time, approaching exponentially the value of the alternative fuel) ranges from about US$0.15/mcf to US$2.00/mcf. A reasonable estimate would be toward the lower end of this range.

11.13 In this context, it is best to treat the depletion allowance for both price setting and strategic planning purposes as indicating a range of economic costs for gas rather than as a specific figure. It is clearly desirable to take account of a positive depletion allowance, to reflect the risk to Bolivia of prematurely exhausting its gas resources. The size of the allowance to be adopted, however, depends on the degree of risk that the country is prepared to accept. A low depletion allowance assumes a relatively large volume of future discoveries, with a corresponding risk of premature exhaustion of supplies owing to a shortfall in discoveries. A high depletion allowance assumes a low volume of future discoveries, with a risk of discoveries exceeding the assumed figure and of failure to capture the full benefits of low-cost gas in earlier years. In the case of Bolivia, it should be noted that the large role of gas in exports and the economy means that the country may have a limited capacity to absorb the effects of errors in the forecasts of gas supply or demand, leading to premature exhaustion of reserves. A prudent strategy would thus be to take a conservative view of potential future discoveries in setting prices at any point in time. This process, however, should be dynamic with periodic (at least five yearly) reviews of the situation to take account of changing knowledge about future reserves.

Table 11.1 Depletion Allowance Calculation

	Depletion Aalowance ($/mcf)	
New discoveries to 2040 (in bcf)	*1992 value*	*Levelized*
0	0.75	1.97
2,000	0.43	1.34
4,000	0.22	0.86
5,000	0.03	0.14

Source: Mission estimates.

Market Value of Gas

11.14 Although the theoretical economic cost of gas as estimated above is one factor to be taken into account in setting the price of gas, it is also important to take account of market realities. In a market-based system, the price of gas is set either by its market value relative to its substitutes if gas is in short supply, or by competition between gas suppliers if it is in surplus. In Bolivia, the key issues of market context are the following:

- ***Surplus market.*** In the case of a failure to open the market to Brazil, prices would be set by gas-to-gas competition in the domestic market, given the bottleneck on exports to Argentina. Prices in this case could be very low, hypothetically about US$0.50/mcf delivered Rio Grande, or less. In this case, pricing policy for gas at the wellhead should be based on the economic cost considerations referred to above and the need for financial viability of producers. A price below US$0.50/mcf is unlikely to be sustainable within this framework.

- ***Export-based market.*** In the case in which a substantial outlet is opened to the market in São Paulo and the rest of southern Brazil, a much tighter market is likely to emerge in the medium term. Assuming that the market in Brazil can absorb supplies above the original contract as they become available (see chapter 9), the marginal value of gas will eventually be set by the netback from Brazil. The precise dynamics of prices will essentially depend on the balance between new gas discoveries and available outlets in the Brazilian market. In equilibrium, new discoveries would be balanced by the growth of domestic and export markets, and the equilibrium price would essentially be the netback from the Brazilian market. If new discoveries greatly outpace market growth, prices will be prone to fall below the netback to Brazil, as producers compete for incremental sales. If discoveries fall significantly short of those required to meet market growth, prices will rise as gas retreates from lower-value markets (fuel-oil substitution) to higher value markets (LPG/diesel, power generation). In this situation, the issue of the relative value of gas on the domestic market and the export price to Brazil could become an important issue. In general, where the Brazilian market is capable of absorbing any additional available supplies, it will be appropriate to set domestic prices with reference to the marginal value of gas in the export market.

11.15 The commodity price of gas in the export market case is likely to oscillate between the extreme low of production cost, and the higher ranges of the netback value to Brazil. It is worth noting that matters are further complicated by likely developments in the overall regional market. Taking into account the factors discussed in chapters 7 and 8, it is clear that the Bolivian market will become increasingly linked to the liberalized Argentine market in future. A tightening market in Argentina, owing to rapid gas demand growth (especially for combined-cycle power) and lagging new discoveries, will have an upward effect on gas prices in Bolivia. A depressed gas market in Argentina (low demand relative to new discoveries) will similarly depress the Bolivian market.

11.16 Another important factor to take into account in setting wellhead gas prices is the requirement for financial viability for existing gas producers, and the need for incentives to new investors. This is essential if additional liquids and gas resources are to be discovered. In the case of existing producers, the joint production of liquids and gas means that even relatively low gas prices would satisfy their financial requirements given the value of liquids produced. In the case of new producers, however, Bolivia must take account of the fact that it is competing for scarce exploration and development capital with other countries in the region (such as Argentina and Peru) and in other parts of the world. It is important, therefore, that the prices offered to producers are seen as attractive in relation to opportunities elsewhere. Again, the need to take account of returns earned by producers in such areas as Argentina will be important.

Gas Pricing Policy

11.17 As discussed in chapter 12, a primary objective of energy policy in Bolivia should be to move toward a market-based framework for natural gas, in which buyers and sellers interact through open access to a regulated pipeline system. In practice, such a system cannot be achieved for some time, given YPFB's effective monopoly over gas sales and the limited number of buyers and sellers in the market. In the medium term, it is thus likely that MEH will continue to have to set the price for gas delivered to the pipeline inlets. However, in setting this price, economic and market factors referred to above should be taken into account. This report does not intend to advocate a specific price level for the commodity cost of gas in Bolivia. However, a thorough study should be undertaken of all the factors referred to above, so as to arrive both at a suitable gas pricing policy and a transitional path toward market-based pricing (see also chapter 12).

Transmission and Distribution Tariffs

Rationale for Multipart Pricing

11.18 Currently, YPFB's prices for gas are for a "bundled" service—that is, both the gas and the transport are charged for within a single per-unit price. Moreover, the prices do not reflect the actual costs, financial or economic, of providing natural gas to customers. In many cases, these prices may not allow YPFB to recover its expenses. The prices also make no distinction between customers according to either volume required or distance over which the gas must be transported. A large industrial customer in Santa Cruz pays the same price as a small industrial customer in La Paz, although the former benefits both from economies of scale in transport and from proximity to the gas fields.

11.19 To price gas to customers in Bolivia, it is necessary to establish two kinds of tariffs: *transport tariffs,* which cover the long-distance delivery of gas to large customers such as power generators or local distribution companies (as well as occasionally large industrial users); *distribution tariffs,* which cover the transfer of gas by distribution companies from interconnections with transporters (at the city gate) to residential, commercial, and industrial users. In both cases, tariffs should be established using the principle that the economically efficient price should cover the LRMC of supply. In practice, it is necessary to adjust prices based on marginal cost to take account of the financing requirements of utilities (including both short term operating expenses and long term capital expenses). This should be done however, in a way that leads to the least deviation from the economically efficient outcome.

11.20 As indicated above, tariffs for the transport and distribution of gas can be itemized separately to customers from the charges for gas volume (at the entry to the pipeline system). This distinction is important in efficient gas pricing. It allows the price of gas itself, as determined by the supply and demand for this commodity, to be differentiated from the price for the service of transporting and distributing the gas.

11.21 The most efficient tariff design for gas transport and distribution is the two-part tariff. The first portion of the tariff is an initial reservation (demand) charge that a customer pays to guarantee delivery of gas. The fee varies with the amount of deliveries reserved (usually expressed as a daily volume), but not with actual deliveries. It generally reflects long-term capital costs. The second charge is a volumetric usage charge that is levied on each unit of gas actually delivered. The volumetric charge generally reflects short term operating expenses, plus the cost of the commodity.

11.22 Such two-part tariffs enhance efficiency in several ways: First, they allow the total price of gas to reflect LRMCs, but still allow day-to-day purchase decisions to be based on only the relevant volumetric short-run marginal costs. Second, to the extent that prices must in general deviate from marginal costs, a two-part tariff allows the deviation to be concentrated in the reservation charge, where it is designed to have less effect on demand, at least in the short term. Finally, multipart tariffs improve the financial stability of the entities that deliver gas because they allow the structure of the revenue stream to match the predominantly fixed structure of their costs.

11.23 The importance of two-part tariffs as market signals can be seen with reference to the prices charged by YPFB to ENDE. ENDE is the largest consumer of gas in Bolivia and uses gas turbines, in part, to balance any shortfalls in deliverability from its hydro stations. The need to operate these turbines thus depends on the amount of hydro capacity available to the grid in relation to demand, at any particular time. Hydro availability is a function of both capacity built and rainfall. To ensure power deliveries, ENDE must have sufficient gas turbine capacity to compensate for hydro shortfalls in a dry year. It must reserve a corresponding gas delivery capacity from YPFB, even if it does not use this in a year of normal rainfall. If YPFB were to charge ENDE solely on the basis of volumes delivered—as opposed to volumes reserved—it would find itself incurring major capital expenses without the assurance that ENDE would pay for them. On the other hand, in planning its power investment, ENDE will not have a clear picture of the fixed and variable costs of incremental power capacity unless YPFB charges gas tariffs that reflect separately the fixed and variable costs of gas supply (for a further discussion of these issues, see also chapter 5).

Setting of Transport Prices

11.24 There are at least two general determinants of the LRMC of gas transport. The first is distance because the cost of transporting gas rises with distance; and the second is size because the cost of expanding delivery capacity on a large pipe is generally less than on a smaller one.

11.25 In a relatively large country such as Bolivia, where gas consumption centers are widely dispersed, in calculating gas tariffs, it is particularly important to allow for distance of transport. To reflect the importance of distance in the transport tariffs, the Bolivian pipeline system has been divided into eight geographical zones, reflecting the pattern of gas usage throughout the country. As a reflection of the effect of size on

transport costs, the transportation network has been broadly split into two divisions: The first is the current YABOG pipeline from Santa Cruz to Argentina (which is also used to move some gas for the domestic market in Southern Bolivia, for example, Tarija). The second would be the remaining YPFB pipelines. The YABOG pipeline, with an average diameter of 24 in., is much larger than the remaining pipelines, which have diameters of 6 to 10 in.

11.26 Two types of pricing can be developed on the basis of the pricing zones. Zone-matrix prices would take account of both the origin of the gas (for example, from the center area around Santa Cruz or the southern fields) and the destination (for example, Cochabamba or La Paz). Destination-only prices would take account only of the point of receipt of the gas, thus accounting for the weighted average distance traveled by gas to supply that zone. In general, zone-matrix prices are appropriate when a transporter provides a gas transport service (that is, an unbundled service) to a variety of gas suppliers who thus need specific point-to-point tariffs. Where a transporter provides a service consisting of both gas transport and natural gas, a destination-only price system is appropriate because the transporter can optimize gas deliveries across the system.

11.27 The assumption in the case of Bolivia is that in the first instance YPFB will continue to provide a bundled service, purchasing gas from producers at the wellhead as required. In the longer run, however, once split into a separate company (as recommended in chapter 12), YPFB's pipeline system can provide transportation services to customers on an open-access basis. In this case, a zone-matrix system will be required.

11.28 Transport tariffs consist of two parts: The reservation (demand) charge would recover the capital costs of the existing system and of incremental capacity, based on each unit of gas delivery reservations. Because such reservations reflect customers' expected peak usage, it effectively apportions capital costs on the basis of expected peak usage capacity (general overhead costs are also put into the demand charge). The volumetric (usage) charge reflects the short-term operating costs of transportation and would be charged only for each unit of gas actually purchased.

11.29 The two-part tariff would apply only to firm customers who are willing to pay an up-front reservation fee in return for a guarantee of service. Customers who are willing to accept a curtailment of service could pay an interruptible tariff. In principle, the cost of serving these customers is limited to short-term variable costs, that is, the usage charge of the firm tariff. In the case of Bolivia, however, setting the interruptible price at such a low level risks limiting the number of firm customers because the Bolivian transport system has significant excess capacity (at least over some segments). Hence, customers may opt for an interruptible tariff in the belief that the risks of curtailment are relatively small. These customers would effectively be gaining a firm delivery of gas without contributing toward the capital cost of the pipelines. To overcome this problem, the interruptible prices should allow for a contribution toward capital costs. In the examples shown, they are based on the total charges that a firm customer would pay if gas was delivered up to its full peak-day reservation every day of the year (a 100 percent load-factor charge).

11.30 To calculate transport (as well as distribution) tariffs, it is first necessary to determine the revenue requirement (or cost of service) for the transporter, in this case YPFB. This includes the following elements: an annualized charge to cover the cost of new investments (as calculated from a required transmission expansion plan), an annualized charge to recover the cost of existing assets, operating and maintenance expenses, and a measure of overhead expenses (estimated from YPFB's financial statements).

11.31 In estimating tariffs, a distinction should be made between those costs that vary with the distance that the gas travels (distanced costs) and those costs that do not (nondistanced costs). The primary distanced costs are capital costs, maintenance, and compressor-fuel consumption. Overhead expenses such as administration comprise the bulk of the nondistanced costs.

11.32 To convert distanced costs into unit prices, it is necessary to take into account both the distances traveled by gas within the system and the volume of gas. This is done by calculating both the total volume of gas flow on the peak days and the distance traveled, to derive a combined total of km-mcf. One km-mcf occurs when 1 mcf of gas travels 1 km, or when 10 mcf of gas travel 0.1 km. To calculate zone-matrix prices, distanced costs are divided by the total km-mcf to produce a unit cost per km-mcf. This figure is then multiplied by the distance between zones to derive a cost per mcf of capacity for that zone combination. Destination-only tariffs are a weighted average of zone tariffs, taking account of average distances that the gas must travel to each zone. Nondistanced costs are calculated per mcf by dividing total costs by the projected (actual) volume of deliveries on the system.

11.33 It is worth noting that to encourage transporters to move gas, it may be desirable to place some of the fixed costs in the volumetric component. Such a pricing strategy gives the transporter an incentive to achieve higher load factors and to operate efficiently. In this respect, there is some trade-off between economic efficiency and operational efficiency. The proportion of the fixed costs transferred in this manner should be relatively small, perhaps 10 percent.

11.34 Estimated delivery zone tariffs for 1991 are shown in Table 11.2. Because of some data limitations these tariffs were estimated using some simplifying assumptions. The key strategic conclusion to be drawn from these figures is that the nature of gas consumption and transport in Bolivia impose high costs on customers operating away from the gas fields, particularly those with relatively low loads (for example, Tarija).

Table 11.2 Estimated Transport Tariffs by Delivery Zone, 1991

Delivery zone	*Monthly demand charge (US$/mcf of daily capacity*	*Usage charge (US$/mcf delivered)*	*Fuel and loss volumes (% of gas delivered)*	*Interruptible tariff (US$/mcf delivered)*
Santa Cruz	9.23	0.02	0.83	0.32
Tarija	37.87	0.10	1.03	1.34
Cochabamba	21.13	0.05	2.52	0.74
Oruro	25.04	0.06	3.14	0.88
La Paz	30.73	0.07	4.04	1.08
Sucre/Potosi	18.16	0.04	2.28	0.64

Source: Mission estimates.

Setting of Distribution Tariffs

11.35 Distribution tariffs differ from transport tariffs principally in that for smaller customers, who make up the majority of distribution customers, costs cannot be apportioned on the basis of a daily delivery entitlement. This is caused by the impracticality of metering residential, commercial, and smaller industrial customers on a daily-usage basis. Larger industrial customers, however, can be metered in a way that allows their actual requirements to determine tariffs.

11.36 There are four major cost components of the LRMC for distributors. They are the following:

a. ***Marginal customer costs.*** These arise simply because a customer is connected to the system. They consist of the costs of keeping a meter and regulator and of providing basic service available for the customer's use, as well as the costs of reading the meter, rendering the bills of service, and maintaining the meter and regulator.

b. ***Marginal distribution facilities costs.*** These are the costs of the pipelines sized to meet each customer's maximum demand rather than the maximum demand of the entire system. Because the individual demands of smaller customers are not known, they reflect generalized demands that vary by customer class. These facilities include the medium pressure lines that serve individual neighborhoods and customers. Larger industrial customers may not use these facilities at all. In fact, they may be responsible for their own connections to the high-pressure system.

c. ***Marginal capacity costs.*** These are the costs of capacity that serves system-wide load. This includes the cost of high-pressure main lines, meeting the demand of all or most customers.

d. ***Short-run marginal operating costs.*** These include the costs that vary directly with the volumes delivered, including the cost of distribution itself and additional transport usage charges, if any.

11.37 As with transport tariffs, distribution tariffs should consist of a two-part charge. For industrial customers, who are large enough for daily metering to be feasible, tariffs would be similar to the firm and interruptible tariff formats for transport prices. The firm demand charge would be based on peak-day reservations, and the firm usage charge on actual deliveries. The interruptible tariff would consist of a one-part charge levied on actual deliveries. For most industrial customers, the distribution companies will provide a firm merchant service with a bundled price that includes the cost of gas, gas transport, and gas distribution expenses. Some larger industrial customers may desire firm or interruptible distribution transport service, however. These services would correspond to the firm or interruptible service similarly contracted for by these companies with the transport companies. These services should be priced separately and contain specific terms and conditions applicable to them. The rights of customers to obtain unbundled service would be set out within the applicable gas code regulations.

11.38 For similar customers, including all residential and nearly all commercial customers, tariffs would consist of a two-part charge. The first part would be a flat monthly reservation charge, which would vary only by customer class. This charge would be calculated on the basis of the customer costs (metering, regulator, and so forth) and of distribution facilities costs (the cost of the low-pressure system). The usage charge will include both variable operating costs and capacity costs, calculated on the basis of volume deliveries.

11.39 The rationale for including capital costs, such as capacity costs, in the usage charge for smaller customers is that, for these customers, congestion costs cannot be apportioned on the basis of individual reservations of capacity. Hence, actual usage (as charged) is used as a proxy to allocate costs to users, placing the greatest demands on the system. This method ensures that customers receive the correct signals of the long-run marginal costs of the system.

11.40 Bolivia's gas usage does not currently include a space-heating load. However, it is conceivable that such a load could develop in the longer term in the cities located at high altitude (e.g., La Paz, Oruro), where nighttime temperatures can be sufficiently low to justify heating. Should such a demand develop, it would justify introducing an element of seasonality into tariffs. This would be done for distribution tariffs by placing the cost of distribution facilities in the usage charge, with a heavier concentration during the winter months. The rationale for this is that with a space-heating load, the cost of distribution facilities also needs to be apportioned according to actual demands placed on the system. In addition, if seasonal space-heating demands become significant, an element of seasonality could be introduced into the transport tariffs for the pipelines if there is seasonal variation.

11.41 Currently, nearly all gas distribution in Bolivia is destined to industrial customers. To calculate tariffs, planned costs have been used for the distribution systems planned for the cities of Santa Cruz, Cochabamba, La Paz, and Sucre. These calculations are shown in Table 11.3.

Table 11.3 Distribution Tariffs, by Sector

	Residential		*Commercial*		*Industrial*	
City	*Monthly (US$/ cust.)*	*Usage (US$/ mcf)*	*Monthly (US$/ cust.)*	*Usage (US$/ mcf)*	*Monthly (US$/ cust.)*	*Usage (US$/ mcf)*
Santa Cruz	3.70	0.77	27.20	0.62	16.87	0.02
Cochabamba	6.38	1.41	34.22	1.23	30.76	0.05
La Paz	6.10	1.93	37.54	1.73	39.25	0.08

Source: Mission estimates.

11.42 Table 11.4 shows calculated final average gas costs to the major users, based on average consumption values, in comparison with existing prices as established by MEH. Total average per unit prices are shown for a range of possible wellhead commodity gas costs of US$0.50 to US$1.25/mcf. It can be seen that only in the case of prices to larger users (including commercial users) in Santa Cruz, do current prices reflect actual average costs. Prices to residential customers are too low in all cases, although at present these are barely applicable because residential distribution networks are not yet in place. The current costs of gas to ENDE in Cochabamba appears to be too low, as discussed in chapter 5. Industrial users in both La Paz and Cochabamba are also probably not paying the full costs of gas production, transportation, and distribution.

Table 11.4 Average Calculated Gas Tariffs versus Current Gas Prices, by City (US$/mcf)

City	*Wellhead*	*Transport*	*Distribution*	*Total price*	*Current price*
Santa Cruz					
ENDE	0.50 - 1.25	0.57	0.00	1.07 - 1.82	1.25
Industrial	0.50 - 1.25	0.57	0.15	1.22 - 1.97	2.00
Commercial	0.50 - 1.25	0.57	0.79	1.86 - 2.61	3.15
Residential	0.50 - 1.25	0.57	3.65	4.72 - 5.47	3.33
Cochabamba					
ENDE	0.50 - 1.25	0.94	0.00	1.44 - 2.19	1.25
Industrial	0.50 - 1.25	0.94	0.38	2.12 - 2.57	2.00
Commercial	0.50 - 1.25	0.94	1.54	2.98 - 3.73	3.15
Residential	0.50 - 1.25	0.94	6.42	7.86 - 8.61	3.33
La Paz					
Industrial	0.50 - 1.25	1.37	0.32	2.19 - 2.94	2.00
Commercial	0.50 - 1.25	1.37	1.18	3.05 - 3.80	3.15
Residential	0.50 - 1.25	1.37	6.24	8.11 - 8.86	3.33

Source: Mission estimates.

12

Institutional and Regulatory Framework

12.1 Natural gas development requires a strong, specific focus independent of the effort traditionally devoted to develop oil. The skills involved in gas transport, marketing, and policy development are in many ways distinct from those found in the oil sector. Moreover, natural gas competes with oil both for markets and for scarce investment and human resources. In developing countries, the lack of adequate institutional development and the domination of the hydrocarbons industry by oil interests have marked the natural gas subsector. Bolivia's institutional and regulatory framework for natural gas suffers from some of these problems, which are compounded by the structural deficiencies of the hydrocarbons sector as a whole.

Hydrocarbons Sector Deficiencies

12.2 The Bolivian hydrocarbons sector suffers from the following serious institutional deficiencies that affect both oil and gas:

a. Government and ministerial capacity to formulate and administer policy is weak, owing to staff shortages and lack of experience and proper role definition.

b. YPFB is involved both as the primary operator in the hydrocarbons business and as a collaborator in policy formulation.

c. The excessive dependence of the government on hydrocarbons taxes distorts the government's policy formulation in the energy sector.

d. YPFB has an effective monopoly over much of the hydrocarbons business owing to a combination of policy and structural factors.

e. Widespread inefficiency in YPFB, including a lack of technical, commercial and planning capacity.

f. A lack of transparency in YPFB's operations and finances is evident, caused by lack of MEH control capacity and procedures and the distorting effect of fiscal policy for hydrocarbons.

g. The legal-regulatory framework for hydrocarbons has been weak and fragmented.

12.3 Thus, the general institutional reform measures needed to address these issues, which are common to both oil and gas, are outside the scope of this study. This chapter focuses on issues specific to natural gas.[40]

Current Institutional Structure of the Gas Industry

YPFB

12.4 Although various companies and institutions are active in the gas industry in Bolivia, YPFB has a dominant position. YPFB is present throughout the gas chain, from production to final sales. Its role differs in the different segments, however.

- ***Production.*** YPFB produces 64 percent of natural gas from its own fields and accounts for 62 percent of domestic gas sales. It also grants operations and association contracts to private producers and takes a share of production from their fields, administers their compliance with commitments, and supervises operations jointly with the private producer. YPFB takes possession of all natural gas at the wellhead, and returns to the private producers their net entitlement after deduction of taxes and YPFB's share of production. YPFB's exploration and production operations are located in Santa Cruz, although administration of contracts is also handled at the La Paz headquarters.
- ***Marketing.*** Because it takes over most of the gas produced, either from its own fields or as the Bolivian state's share, YPFB controls most gas production. In principle, private companies could market their own share of gas (and build their own pipelines); however, YPFB has a legal monopoly over exports and a de facto monopoly over the pipeline system. Hence, YPFB has a de facto monopoly over wholesale gas marketing.
- ***Transmission.*** YPFB does not have a legal monopoly over gas transmission lines, but in practice, owns all lines in the country. Responsibility for the transmission system is split between the *gerencia industrial,* or industrial directorate, in Cochabamba (where downstream oil processing, transportation, and distribution are also handled) and YABOG in Santa Cruz. The industrial directorate handles all pipelines in the Center and West of the country (see chapter 3). YABOG is a separate subsidiary of YPFB set up originally to own and operate the pipeline to Argentina, although it now runs both the Argentina system and all lines in the East and South of the country.
- ***Distribution.*** YPFB's operational role in distribution is limited, consisting of direct sales to ENDE through the high-pressure system and sales to industrial consumers in areas where no independent distribution companies have been

[40] Institutional reform measures are addressed in the LAC Region Report "Bolivia Public Enterprise Reform and Private Sector Development." Of particular interest is a section on hydrocarbons to which ESMAP staff contributed.

established (for example, La Paz). YPFB's natural gas division has worked with foreign technical assistance to develop the plans for gas distribution in the main cities of Bolivia separate from other gas pipeline divisions as it is under the vice-presidency of administration and finance (the other areas all being under the vice-presidency of operations). The division constitutes the main center of technical knowledge about residential and commercial distribution in Bolivia. Government policy has been to remove YPFB from final distribution of gas, although YPFB may have a role in implementing new distribution networks for subsequent sale to the private sector.

- ***Planning and policy.*** YPFB participates closely in most aspects of government policy formulation and administration for natural gas (as for oil).

Private Producers

12.5 Private companies (Sol Petroleo, Tesoro, Perez Companc, Pluspetrol) produce both gas and liquids under operations and (less commonly) improved recovery contracts. These companies account for 36 percent of gas production and 38 percent of domestic sales (although their net share is lower). They essentially deliver their gas to YPFB at the wellhead, receiving a price that reflects the netback value from sales (mainly for export to Argentina) less a modest transport and handling charge. Payment is made to the companies by YPFB, although in recent years there have been constant delays in payments for both gas and oil. (This can be ascribed both to the government taking the funds from YPFB and to a lack of attention by YPFB to its operators' interests.) Other companies that are exploring (for example, Texaco, Maxus) may also become gas producers in the future.

Distribution Companies

12.6 The government's policy of removing YPFB from the final sales of gas (and oil) led to the forming of independent distribution companies in the late 1980s in Cochabamba, Santa Cruz, Tarija, and Sucre. These companies initially functioned mainly as agents for YPFB and received a commission. Moves were underway (1992) to establish them as distribution companies with concessions to buy gas from YPFB at the city gate for resale to final customers through their own pipelines. The shareholders in the these companies are both private and public entities.

Consumers

12.7 The high penetration rate of gas means that most industries are consumers. ENDE accounts for most gas purchases. Residential and commercial consumption is just beginning to be established. There is limited involvement by individual consumers, including ENDE, in the running of the gas market or in policy development, although industrialists have been vocal in some cases. For example, the association of the Santa Cruz industries that are supplied by Corporación de Desarollo de Santa Cruz (Bolivia)

(CORDECRUZ) [41] which owns the gas grid in the Santa Cruz industrial park, has successfully lobbied for lower gas prices. On the other hand, some industrialists refused to pay the new two-part tariff proposed by the natural gas division, and thus the project was withdrawn.

MEH

12.8 The ministry has overall responsibility for sector policy formulation and execution. It is responsible for setting gas prices to consumers. Within the ministry, most responsibility for administering the sector falls on the subsecretary for hydrocarbons who is responsible for *both* oil and gas. There are no officials whose responsibility is limited to gas matters.

Key Issues

YPFB Organization

12.9 YPFB has no central focus for natural gas within its organization. The split in responsibility for transmission between the industrial management in Cochabamba and YABOG in Santa Cruz results in a lack of coordination in overall transmission system planning, investment, and operation. While YABOG deals purely with gas, the staff handles gas transmission in Cochabamba as well as oil transport pipelines for the whole country, which weakens their commitment to the gas system. Within this framework, the separate continuing role of the small natural gas division is unclear.

12.10 YPFB's upstream operations are generally focused on liquids discovery and production. The imperative to sustain liquids self-sufficiency results in a lack of focus on gas disposals (as evidenced by the large-scale flaring of gas) and a lack of coordination between gas marketing and production. YPFB's multiple role as gas marketer, contracts administrator, and gas producer also leads to potential conflicts of interest in gas production and acquisition decisions. The system by which YPFB operates as producer, transporter, and seller of natural gas results in a lack of transparency in its operations. Accountability is lacking for the costs of each stage of the chain, in particular, between production and transportation. The overall fragmentation of gas activities within YPFB means that there is no "natural gas culture" within the company. This is evidenced by the lack of focus on gas marketing, within Bolivia and particularly for export markets, in which MEH has tended to take the initiative in recent years.

Private Companies

12.11 The existing system encumbers private gas producing companies. These companies already account for a large share of production and reserves and will supply most of the future incremental investment. Yet, YPFB's effective domination of gas sales

[41] CORDECRUZ is a publicly owned entity in charge of developing the economic activity in the *departamento* (large district).

limits these companies' capacity to take initiatives in gas marketing. These companies tend to sell gas passively as required to YPFB, while YPFB's record of poor payments has tended to limit their enthusiasm for additional investment, especially in natural gas. The absence of clear regulatory requirements hampers these companies' efforts to market gas domestically and to build and operate pipelines. The exploratory development of the Bermejo field by Pluspetrol, for integration into its own Ramos field in Argentina, demonstrates the potential for private initiatives in this area.

Distribution Companies

12.12 Having been created in an ad hoc manner without proper tendering procedures or prequalification, distribution companies lack the sound technical and financial base for expansion. This is especially true in the new area of residential and commercial distribution, although these companies have demonstrated a willingness to confront the challenge of building a distribution system by organizing the necessary expertise.

Consumers

12.13 Consumers are largely passive actors in the market. The existence of set prices and deliveries does not encourage a market-oriented purchasing strategy, even among the largest users. This is particularly true of ENDE, whose link in terms of gas purchases and planning with YPFB is weak.

MEH

12.14 The ministry lacks adequate staff and capacity to deal with all the issues arising in the natural gas subsector. In many areas, it must rely on YPFB, which limits its independence of decision and action.

Recommended Reforms

12.15 To improve the overall structure of the gas subsector in Bolivia, reforms need to be undertaken on two fronts: (a) a regulatory framework is needed to set rules for natural gas transport, distribution, and marketing and (b) institutional reform is required in the public sector to improve efficiency, attract private sector capital, and work effectively within the regulatory framework.

Regulatory Framework

12.16 The twin goals of public utility regulation are promotion of industry and protection of the public. To promote private investment in the gas industry in Bolivia, it is essential that the regulatory system that will be applied be as stable, predictable, and free

of political interference as possible.[42] One means of accomplishing this objective is to adopt a statute that would set forth the general regulatory guidelines that would be applied both to promote investment in gas transmission and distribution and to protect consumers. The statute would also create a national commission to implement the guidelines stated therein.

12.17 Any independent commission that is created must be free of political influence to ensure that regulatory policies will be applied in a predicable and evenhanded manner. The commission could function within MEH, and its officials could be appointed by the president, subject to the advice and consent of a congressional committee. This will help to ensure appointment of qualified and relatively independent commissioners.

12.18 The scope and the powers of the commission must be clearly delineated by the statute, so that regulated companies can be certain of the extent of regulation of their activities. The duties of the commission may also be circumscribed, for example, by stating that its power shall not extend to the production of natural gas at the wellhead. Otherwise, the statute should give the commission general and exclusive powers and jurisdiction to regulate and supervise the rates, services, and activities of gas transmission and distribution companies. The gas statute must also identify the entities that will be allowed to perform gas transportation and distribution services (for example, corporations, cooperatives). The permissible ownership of such entities (private, public, municipal, foreign, local, and so forth) could also be defined.

12.19 Basic principles of regulation of gas transmission and distribution (as for most other utilities) are as follows:

- A company would be entitled to charge a reasonable rate for its services, which under prudent and economical management, would cover all its operating expenses, taxes, and a reasonable return on its invested capital (measured in suitable financial terms).
- A company may be entitled to a grant, by public authority, of a franchise for a specific area that would give it an exclusive right to serve customers in that area. (This is more suited to distribution than to transmission companies.)
- Gas companies may need the right to acquire or use private property to carry out a public service (for example, laying pipelines). Laws would provide for just compensation in such cases, enforceable through the courts.
- Companies investing in gas transmission and distribution would have the right to operate under reasonable rules and regulations, including, in particular, predictability of regulation with no unjustified sudden changes in the rules under which they must operate.

[42] The regulatory framework for natural gas in Bolivia was discussed, in detail, in ESMAP's report, "Bolivia Natural Gas Distribution: Economics and Regulation."

12.20 The right to charge a rate that earns a reasonable rate of return is the most effective way to attract capital into business. Rules for assessment follow:

- The rate of return should be similar to those of businesses with similar risks.
- The return should ensure confidence in the financial condition of the company.
- The return should allow the company to attract and support the credit and equity capital required for investment.
- The rate of return should vary with credit market and business conditions.

12.21 Regulation also requires that companies provide service to all financially responsible customers at reasonable rates and without unreasonable discrimination.

12.22 Such a regulatory system would allow the creation of gas transmission and distribution companies that would be allowed to charge reasonable tariffs set by the regulatory commission. Producers and consumers (for example, distribution companies) could thus contract for quantities of gas and reserve the necessary capacity in the pipelines. Distribution companies would be allowed to add a reasonable tariff to the city-gate price to cover their distribution costs (including a reasonable return.)

12.23 The MEH has been working on a draft Natural Gas Code that will embody these principles (based on ESMAP's recommended code). The new government, which took office in August 1993, has integrated the main principles of the draft Natural Gas Code into a draft Hydrocarbon Law. Once the Law has been passed, the Natural Gas Commission will have to develop detailed regulations for the operation of the industry.

Institutional Reform of the Public Sector

12.24 The most important reforms required are in YPFB's organization and working practices. The most urgent is the creation of a single national gas transmission company, which would be in charge of all existing transmission lines in Bolivia. This company could be created relatively easily through the merger of the existing Santa Cruz and Cochabamba gas pipeline groups, with YABOG preferably in the lead given its greater experience in this area. It should be separate from YPFB's other operations, preferably operating as an independent commercial company. The company would operate under the regulatory framework, and would charge regulated tariffs for gas transportation. This would help to ensure efficiency in system planning and operation and transparency of the company's financial structure. The company would also serve to provide a focus for natural gas within the national hydrocarbons industry to counterbalance the weight of oil interests.

12.25 It should be emphasized that the National Gas Transmission Company, however, should not be given a monopoly over new pipeline construction. Construction of new pipelines should be regulated by the commission, but may be undertaken by any qualified private or public entity (in accordance with the Hydrocarbons Law).

12.26 A second important reform within YPFB is the need to create a gas marketing unit. This unit should also cover supply planning, ensuring that production matches market requirements and creating pressure for the efficient development of gas resources. Such a marketing unit is needed if YPFB is to sell gas into pipelines at regulated tariffs and compete with private companies as a seller in the market.

12.27 Because much of the gas marketed in Bolivia is exported, the institutional structure here is especially important. It must be accepted that, for the time being, the government—through MEH—will have a significant role in structuring deals and contracts, because of the national strategic nature of the trade. In addition, to ensure project viability in the medium term, MEH will need to exercise some control over gas exports acting directly or through an appropriate agency. In the long term, however, once the project has become soundly established, the aim of policy should be to encourage free exports of gas (subject to the usual national security clearance). In addition, the pace of liberalization should depend on the progress of energy market reform in neighboring countries. The actual gas export projects, as well as the marketing of gas through the pipeline system, could be done by a joint public-private venture. It is particularly important that continued attention be paid to marketing in Argentina in the short term and that a viable structure be set up to create incentives to market efficiently to Brazil in the future. The marketing of Bolivian gas to Argentina could be undertaken by a specialized group, which could operate on commercial principles.

12.28 In terms of the upstream, any increase in export markets should help to attract private companies into all or most of YPFB's gas production. This should help to provide needed investment funds to and improve efficiency of technical and commercial operations.

12.29 The role of private companies in upstream gas should generally be increased, both to provide the capital necessary for further development and to create a more dynamic market environment. YPFB should be required to associate itself with private partners in all its existing and new fields.

12.30 The MEH's capacity to deal with gas sector issues must be increased. This is required both because of the growing burdens of policy direction in the subsector, as export market issues become more complex and because of the forthcoming need to deal closely with the independent gas commission. A senior official at the subsecretary level, supported by a dedicated staff, may well be needed to deal exclusively with natural gas.

12.31 The government needs to assist distribution companies in attracting international partners with the technical and financial capabilities to develop distribution.

12.32 As the largest gas consumer, ENDE should take a more active role in purchasing and monitoring gas and should appoint dedicated staff to monitor gas markets and negotiate gas purchases.

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 - Out of Print)	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 - Out of Print)	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 - Out of Print)	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

continued on next page

Region/ Country	*Activity/Report Title*	*Date*	*Number*
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessment (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 (Out of Print)	12/87	–
	Power Sector Efficiency Study (French)	02/92	140/91
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	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
Guinea	Energy Assessment (Out of Print)	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 (Eng. & 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

Region/ Country	*Activity/Report Title*	*Date*	*Number*
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English - Out of Print)	02/87	–
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English - Out of Print)	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 Rep. 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
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
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 (Eng. & 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

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Region/ Country	*Activity/Report Title*	*Date*	*Number*
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English & French)	08/86	059/86
	Improved Charcoal Production Techniques (English & French)	02/87	065/87
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	–
Sao Tome & 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
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
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 - Out of Print)	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 - Out of Print)	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

Region/ Country	*Activity/Report Title*	*Date*	*Number*
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in Brick and Tile Industry (Eng.)	02/89	097/89
	Tobacco Curing Pilot Project (English - Out of Print)	03/89	UNDP Term. Rept.
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
	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 - Out of Print)	09/89	–
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	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
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

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Region/ Country	*Activity/Report Title*	*Date*	*Number*
	Biomass Gasifier Preinvestment Study Vols. I and II (English)	12/90	124/90
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
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 - Out of Print)	–	–
	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
Solomon Is.	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979/SOL
South Pacific	Petroleum Transport in the South Pacific (English - Out of Print)	05/86	–
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English - Out of Print)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English - Out of Print)	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	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85

Region/ Country	*Activity/Report Title*	*Date*	*Number*
	Small Scale Uses of Gas Prefeasibility Study (English - Out of Print)	12/88	–
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	05/91	120/91
	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
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 - Out of Print)	05/88	–
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	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

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Region/ Country	*Activity/Report Title*	*Date*	*Number*
	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 - Out of Print)	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
Chile	Energy Sector Review (English - Out of Print)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	–
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	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	–
	Energy Strategy (English)	04/91	–
	Private Minihydropower Development Study (English)	11/92	–
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
	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

Region/ Country	*Activity/Report Title*	*Date*	*Number*
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 - Out of Print)	03/88	–
	Energy Efficiency Standards and Labels Phase I (English - Out of Print)	03/88	–
	Management Information System Phase I (English - Out of Print)	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 - Out of Print)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English - Out of Print)	09/85	–
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English - Out of Print)	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	–
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent & Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English - Out of Print)	12/85	5930-TR
	Global		
	Energy End Use Efficiency: Research and Strategy (English - Out of Print)	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	–

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

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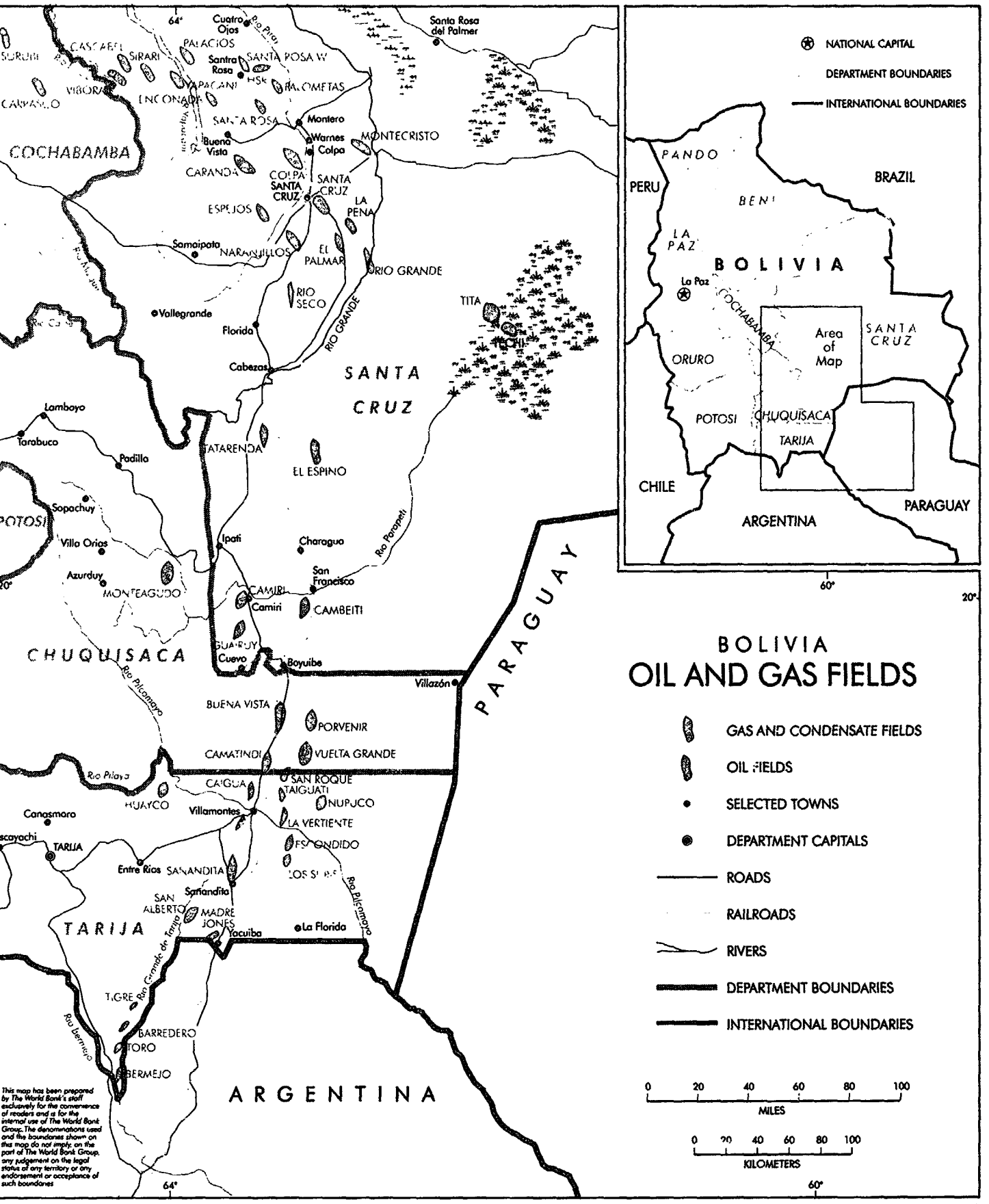

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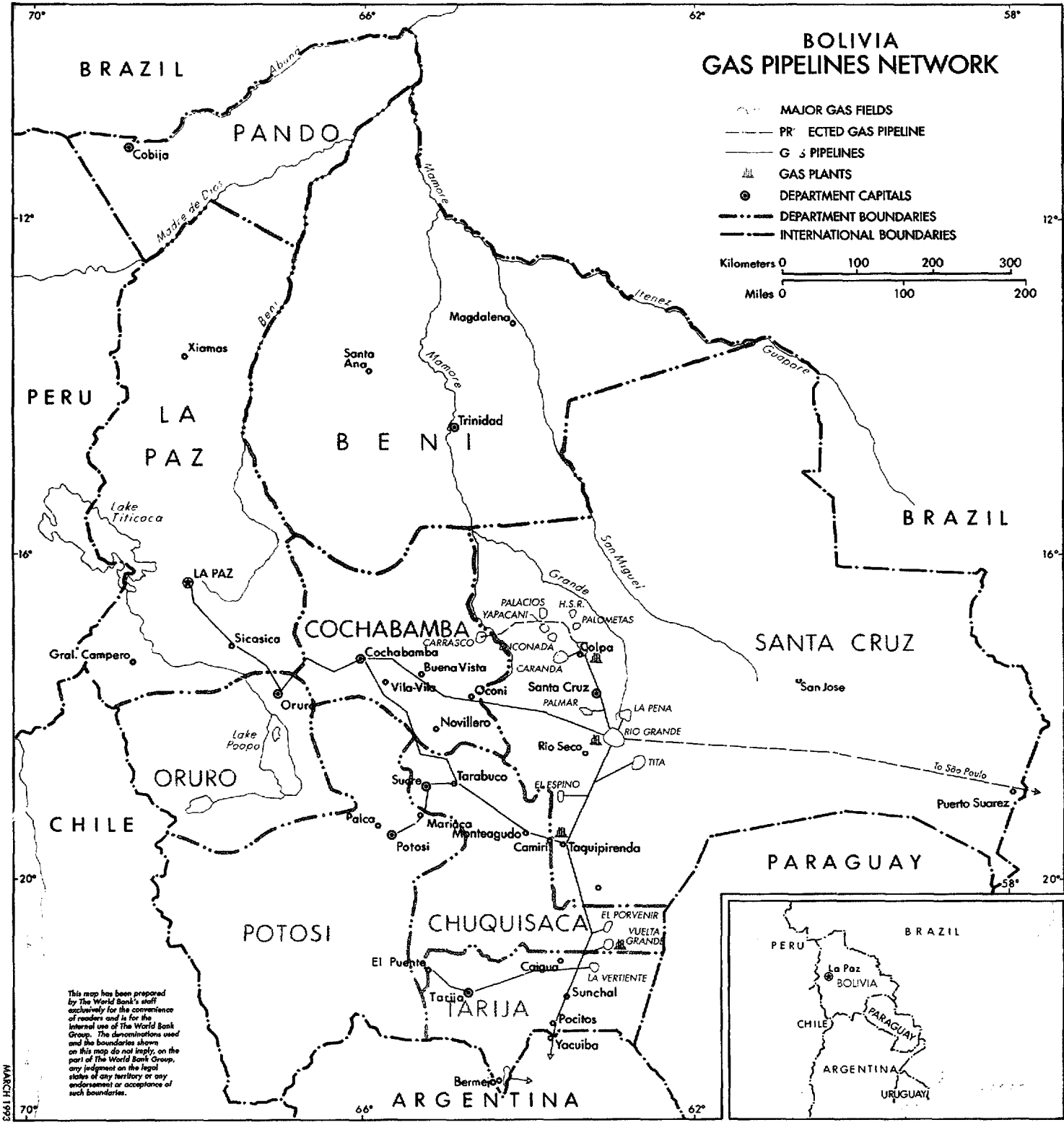
BOLIVIA
GAS PIPELINES NETWORK
MAJOR GAS FIELDS
PROJECTED GAS PIPELINE
GAS PIPELINES
GAS PLANTS
DEPARTMENT CAPITALS
DEPARTMENT BOUNDARIES
INTERNATIONAL BOUNDARIES
Kilometers 0 100 200 300
Miles 0 100 200
BRAZIL
PANDO
Cobija
Madre de Dios
Abuna
Beni
Mamore
Itenez
Guapore
Magdalena
Santa Ana
Xiamas
PERU
LA PAZ
BENI
Trinidad
Lake Titicaca
LA PAZ
BRAZIL
San Miguel
Grande
PALACIOS
YAPACANI
H.S.R.
PALOMETAS
COCHABAMBA
CARRASCO
INCONADA
Colpa
CARANDA
Sicasica
Gral. Campero
Cochabamba
Buena Vista
Vila-Vila
Oconi
Santa Cruz
PALMAR
LA PENA
RIO GRANDE
SANTA CRUZ
San Jose
Oruro
Lake Poopo
Novillero
Rio Seco
TITA
To São Paulo
Puerto Suarez
ORURO
Sucre
Tarabuco
EL ESPINO
CHILE
Palca
Mariaca
Potosi
Monteagudo
Camiri
Taquipirenda
PARAGUAY
POTOSI
CHUQUISACA
EL PORVENIR
VUELTA GRANDE
El Puente
Caigua
LA VERTIENTE
Tarija
TARIJA
Sunchal
Pocitos
Yacuiba
Bermejo
ARGENTINA
70°
66°
62°
58°
12°
16°
20°
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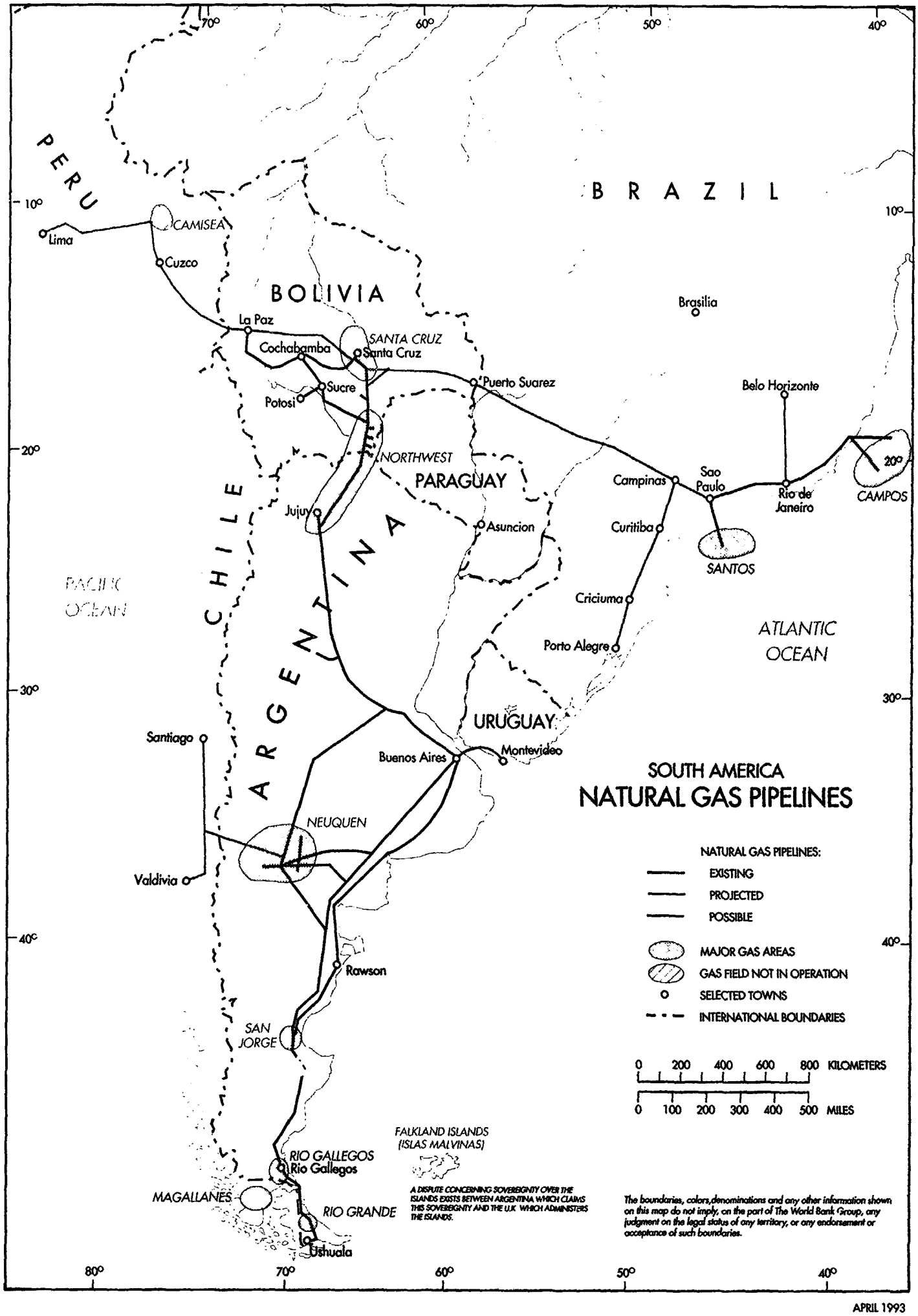
MARCH 1993
IBRD 22704
BRAZIL
PERU
La Paz
BOLIVIA
CHILE
PARAGUAY
ARGENTINA
URUGUAY


SOUTH AMERICA
NATURAL GAS PIPELINES
NATURAL GAS PIPELINES:
EXISTING
PROJECTED
POSSIBLE
MAJOR GAS AREAS
GAS FIELD NOT IN OPERATION
SELECTED TOWNS
INTERNATIONAL BOUNDARIES
0 200 400 600 800 KILOMETERS
0 100 200 300 400 500 MILES
PERU
BRAZIL
BOLIVIA
PARAGUAY
CHILE
ARGENTINA
URUGUAY
PACIFIC OCEAN
ATLANTIC OCEAN
CAMISEA
Lima
Cuzco
La Paz
Cochabamba
SANTA CRUZ
Santa Cruz
Sucre
Potosi
Puerto Suarez
Brasilia
Belo Horizonte
NORTHWEST
Jujuy
Asuncion
Campinas
Sao Paulo
Rio de Janeiro
CAMPOS
Curitiba
SANTOS
Criciuma
Porto Alegre
Santiago
Buenos Aires
Montevideo
NEUQUEN
Valdivia
Rawson
SAN JORGE
RIO GALLEGOS
Rio Gallegos
MAGALLANES
RIO GRANDE
Ushuala
FALKLAND ISLANDS (ISLAS MALVINAS)
A DISPUTE CONCERNING SOVEREIGNTY OVER THE ISLANDS EXISTS BETWEEN ARGENTINA WHICH CLAIMS THIS SOVEREIGNTY AND THE U.K. WHICH ADMINISTERS THE ISLANDS.
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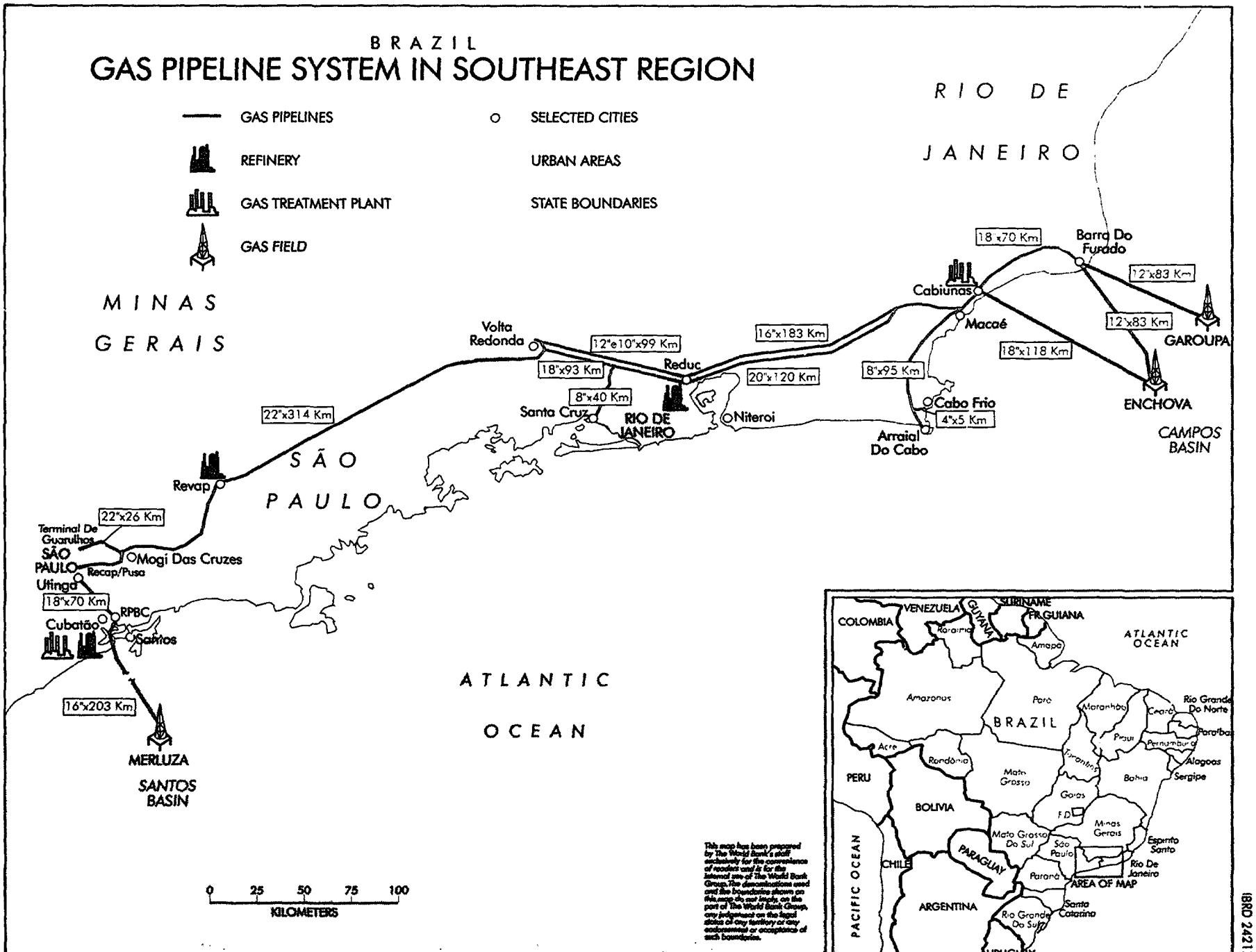
80° 70° 60° 50° 40°
10° 20° 30° 40°

BRAZIL

GAS PIPELINE SYSTEM IN SOUTHEAST REGION



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