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Natural Gas Pricing and Regulatory Study

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MEASURES

CFD	=	Cubic Feet per Day
MMCFD	=	Million CFD
CM	=	Cubic Meter
CMD	=	Cubic Meter per Day
MMCMD	=	Million CMD
CMY	=	Cubic Meter per Year
MMCMY	=	Million CMY
BCM	=	Billion Cubic Meters
BCF	=	Billion Cubic Feet
TCF	=	Trillion Cubic Feet
BTU	=	British Thermal Unit
MMBTU	=	Million BTU
TOE	=	Ton of Oil Equivalent
MMTOE	=	Million TOE
MMT	=	Million Tonnes
MMTPA	=	Million Tons per Annum
Kwh	=	Kilowatt hour
Twh	=	Terawatt hour
Kw	=	Kilowatt
Mw	=	Megawatt
Kcal	=	Kilocalorie
Kg	=	Kilogram
bbl	=	barrel

ABBREVIATIONS

GOB	Government of Brazil
YPFB	Yacimientos Petroliferos Fiscales Bolivia
MOF	Ministry of Finance
MME	Ministry of Mines and Energy
DNC	Departamento Nacional de Combustibles
CEG	State Gas Company of Rio de Janeiro
CPD	Sao Paulo Development Company
GDP	Gross Domestic Product
FUP	Frete de Uniformizacao de Precos
AIC	Average Incremental Cost
LRMC	Long Run Marginal Cost
SRMC	Short Run Marginal Cost

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FOREWORD

This report was written by Peter Law (Energy Specialist, World Bank). It is based on a World Bank gas sector mission carried out in July 1993, and it has been updated to take account of recent important events in the sector. Its purpose is to identify and make recommendations on the issues concerning gas sector regulation and fuels pricing in Brazil, which would impact on the viability of the proposed Bolivia - Brazil pipeline project in particular, and on gas development in general.

The report was issued to the Government of Brazil (GOB) in draft form in March 1994 when it was discussed between the Bank and the GOB. In view of the impending elections and the upcoming constitutional review, which was to have considered changes affecting the monopoly status of PETROBRAS, the report was not issued in Final Gray Cover. The monopoly issues were resolved with the constitutional Amendment No. 9 which was enacted on November 9, 1995, and which removes all Constitutional barriers to private sector participation in oil and gas activities in Brazil. In addition, the Concession Law for Public Services was approved by Congress in February 1995, which spells out that all concessions for public services must be awarded under a competitive bidding process. These two events have greatly improved the possibilities for private sector investments in Brazil's oil and gas sector. This report takes account of these events.

The members of the 1993 World Bank gas sector mission were Peter Law (Energy Specialist and Task Manager), Dominique Babelon (Senior Economist), Keta Ruiz (Economist) and consultants Patrick Cayrade and Peter Cameron. The report was reviewed by a peer group consisting of Chakib Khelil (Petroleum Advisor) and Raphael Moscote (Energy and Regulatory Advisor).

The mission is grateful for the effective cooperation of the staff of the Ministry of International Affairs, the Ministry of Finance, the Ministry of Energy and Mines, the Senate, PETROBRAS, the Gas Company of Rio de Janeiro (CEG), the Gas Company of Sao Paulo (COMGAS), Bahia Gas, State of Bahia, State of Sao Paulo, CESP, ELETROBRAS, ELETROPAULO, SHELL, BTB Group, ENRON, TECHNOPLAN, INFRAGAS.

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SUMMARY AND CONCLUSIONS

INTRODUCTION

1. In February 1993, PETROBRAS signed an agreement with YPFB for the importation of 8-16 MMCMD natural gas over a twenty year timeframe. This would require a new international import pipeline and distribution facilities within Brazil, and presents an opportunity for Brazil to increase the share of natural gas in the primary energy supply from 2% to 10%. This could have a number of desirable effects including the amelioration of atmospheric emissions though the displacement of less clean fuels in some of the major cities, the provision of gas supplies to the large ceramics industries which currently depend on expensive alternative fuels, and the opening of possibilities to construct gas-fired power plants to supplement Brazil's hydro-dominated system. However, the efficient development of the gas sector depends on the resolution of the following issues:

(i) Brazil's refinery structure does not allow a high overall degree of conversion and results in an exportable surplus of fuel oil. Investments are needed in refinery upgrading primarily to increase the yields of light ends, particularly diesel oil. This would reduce the yields of the heavier products which in turn affects the prospects for the market penetration of natural gas.

(ii) Gas use for large increments of power generation could lessen the risk of low market take-up in the early years of the expansion of Brazil's gas industry. There has been much uncertainty regarding the economic and financial viability of base load thermal power in South-South East Brazil, particularly in view of the requirement to operate in complementarity to hydropower.

(iii) Price distortions and subsidies on fuels which are in competition with natural gas have been prevalent over recent years. To encourage the economic development of the gas sector, it is essential that a program for price rationalization is established.

(iv) Gas sector development in Brazil needs a large influx of domestic and foreign capital from the private sector. The prospects for this will improve if gas is allowed to compete with alternative fuels without the possibility of arbitrary price interventions, if economic supplies of natural gas may be

assured, and if a satisfactory and transparent regulatory framework is established.

2. In view of these issues, the specific objectives of the study were to:

(i) Identify the price subsidies and economic distortions for natural gas and its competing fuels and propose priorities for price rationalization.

(ii) Identify an appropriate framework within which to price natural gas, taking account of the various approaches to the structure of tariffs.

(iii) Identify alternative legal and regulatory frameworks for the natural gas sector which may be feasible in view of the outcome of the constitutional review.

(iv) Propose alternatives, identifying their advantages and disadvantages, for regulatory bodies which may oversee the development of the gas sector.

Supply and Demand for Gas and Competing Fuels

Supply of Gas

3. Brazil's total volume of proven, probable and possible gas reserves amounts to about 230 BCM of which 154 BCM are proven. Assuming the GOB's efforts to open hyrocarbons exploration and development to foreign private participation (including joint ventures with PETROBRAS) are successful, a further 147 BCM could be added from new discoveries. About 258 BCM could be available for sale up to the year 2015, of which 146 BCM would be for the South-South East region (S-SE). Gas production from already producing fields in the S-SE is expected to remain at 8.5-9.0 MMCMD until 2000, and then decline to about 5.1 MMCMD by 2010. Natural gas imports from Bolivia would supplement domestic production, and together would correspond to a supply availability for the S-SE of 20 MMCMD in 2000, and 24 MMCMD in 2005. If past levels of exploration effort are maintained, Bolivia will build up sufficient reserves to match the 105 BCM needed to meet the supply contract with Brazil, noting that there is good potential for new discoveries in Bolivia with less than 20% of the country having been explored.

Supply of Competing Fuels

4. Currently, Brazil has an exportable surplus of about 2 MMCMY of fuel oil and deficits of 2 MMCMY for diesel oil and 2-3 MMCMY for LPG. Assuming the PETROBRAS refinery upgrading program is fully implemented, this will result by the year 2000 in increased production of gasoline, LPG, and low quality diesel oil, and a stabilization of fuel oil production at 14.5 MMCMY of which 1.2 MMCMY of low sulfur fuel oil will be in exportable excess. The refinery upgrading program suggests that the supply of LPG will be brought more or less into balance by the year 2000.

5. The extent to which the PETROBRAS refinery upgrading program will be implemented is rather uncertain, but it is necessary for PETROBRAS to pursue the program to completion to avoid a large exportable excess of fuel oil, since this would be difficult to displace with natural gas in a deregulated fuels price market. The Constitutional Amendment No. 9 removes the constitutional barriers to the establishment of new refineries by independent companies, and allows PETROBRAS to form joint ventures with independent companies to upgrade existing refineries. Providing the GOB is proactive in opening up the refinery sector, this will lead to a new impetus to refinery upgrading in Brazil, particularly for the conversion of low sulfur fuel oil and in the long run a reduction of the exportable excess. On the other hand, if the refinery upgrading program is not implemented, the importation of natural gas will exacerbate the fuel oil management problem.

Economic Value of Gas and Gas Demand

6. **The Value of Gas in End Use:** The economic demand for gas needs to take account of the competitivity of gas against competing fuels in its various end uses. This is expressed by the netback value or break-even price of natural gas. Gas netback values (at the consumer gate) are high for residential consumers (US$18/MMBTU) reflecting the high economic cost of electricity and LPG displaced. For use as a transportation fuel, the economic gas netback values are estimated to be within the range US$6-12/MMBTU depending on the type of vehicle. Gas has a lower value in industry (US$2.3-3.2/MMBTU) where it displaces fuel oil at export parity, and a higher value (US$3.3-4.2/MMBTU) where it displaces fuel oil at import parity. However, the economic netback values for some industrial uses are quite high in special process uses where high cost fuels such as LPG and charcoal are displaced. It is therefore evident that the economic value of gas in the various markets in S-SE Brazil is reflective of a variety of high and low value uses.

7. Where gas displaces high sulfur fuel oil (and other less clean fuels), the economic economic benefit of natural gas has to take account of the avoided costs of exhaust gas cleanup systems needed to meet environmental standards. In the power sector, the avoided costs of gas cleanup facilities are in the range 0.3 - 0.7 US$/MMBTU for gas combined cycle plants compared with oil or coal plants. These avoided costs differ by class of end user. In order to internalize the environmental benefits of natural gas in its relative price, a tax could be imposed to all hydrocarbon fuels depending on their propensity to pollute. This would penalize dirty fuels such as high sulfur fuel oil, and would promote the development of natural gas in an economically efficient way. Several countries levy an environmental tax on fuels, including Sweden and Norway which impose carbon dioxide and sulfur taxes on heavy fuel oil used by industry. This can evaluated against the effectiveness of the enforcement of the existing environmental standards in Brazil's cities, and the incentives for the consumer to invest in gas cleanup equipment.

8. **Gas Demand Forecasts:** Several gas demand studies have been prepared for regions expected to be supplied by the Bolivian gas pipeline. PETROBRAS' own 1991 forecasts showed an economic demand of 44 MMCMD by the year 2000. Subsequent forecasts included a more realistic evaluation of the impact of gas price on demand, and show that the realizable economic demand for gas by industry in the S-SE (within the service areas of the pipeline) will reach *at least* 20 MMCMD by 2000, which excludes additional gas demand generated by vigorous industrial growth, feedstock requirements and power generation. This indicates that gas consumption will be supply constrained, and suggests the need for Brazil to proactively promote domestic exploration and consider additional gas import contracts for the medium to long term.

The Pricing of Gas and Competing Fuels

Petroleum Fuels Subsidies and Pricing

9. The current petroleum fuels pricing system is shown in Table 1(overleaf), which incorporates four levels of subsidy:

(i) A subsidy representing the difference between cost of imported and domestic crude.

(ii) A cross subsidy allocated to each petroleum product.

(iii) A component (FUP) for uniformization of product prices over the country.

(iv) A formula linking gasoline and alcohol prices resulting in subsidized alcohol prices.

10. **The Ex-Refinery Cost (VMR):** The ex-refinery cost, or Valor Medio Realizacao (VMR) comprises the cost of crude oil and refining costs. The cost of crude oil included in the VMR is set at the cost of domestic crude, which generally (although not always) has a lower cost than imported crude, with the difference between the costs registered in the "Conta Petroleo" destined to compensate PETROBRAS.

11. **The Realization Price (PRi):** The Realization Price (PRi) corresponds to the price of each product at the refinery gate excluding taxes, and includes a cross subsidy between fuels. The Realization Price of each product is set so that the sum of the prices of each product, weighted by respective volumes sold, is equal to the VMR. Cross subsidies are applied from gasoline, diesel and jet fuel, to naphtha, fuel oil and LPG, and the pattern of PRi differs markedly from the pattern of international prices, expressed as CIF Santos.

Table 1: Petroleum Products Fuels Prices and Economic Costs-February 1996 (US$/bbl)

	Average Product	Gasoline	Diesel	Naphtha Petchem	Fuel Oil H.S.	Fuel Oil L.S.	LPG
Ex Refinery Cost(VMR)	18.2	18.2	18.2	18.2	18.2	18.2	18.2
Cross Subsidy		12.4	1.4	-5.4	-3.7	-0.4	-11.2
Realization Price(PRi)	***18.2***	***30.6***	***19.6***	***12.8***	***14.5***	***11.6***	***7.0***
Ex Refinery Price(Inc.Tax)	30.1	58.3	31.2	17.7	21.1	25.1	14.3
Consumer Price(Incl. Tax)	***45.3***	***83.2***	***54.7***	***17.7***	***23***	***26.8***	***31.6***
International Price (CIF Santos)		18.5**	24.7*	23.3*	13.0**	15.3**	22.1*

Source: PETROBRAS & World Bank Estimates
*Based on Import Parity, **Based on Export Parity,

12. **The Price Billed by Refinery:** This refers to the price at secondary distribution bases, and is obtained by adding to the realization price of each product (PRi), the various taxes, financing costs, and the Frete de Uniformizacao de Precos (FUP). The FUP has to cover the transportation costs of all petroleum products from the refineries to the secondary distribution bases, and is a cross subsidization mechanism for achieving geographical equalization of product prices at the secondary distribution level. The net result is that: (i) consumers close to refineries subsidize remote consumers, and ii) consumers of products which incorporate an FUP component in their price build-up subsidize consumers of products which do not. The FUP components are registered in the "Conta Derivados".

13. **The Ex-Retail Distribution Price and Consumer Price:** The price billed by the petroleum products retail distribution companies is obtained by adding the distribution margin , the ICMS tax, the various social contributions, and the financial costs to the price billed by refinery. The consumer price includes the sales margin and the IVVC. In 1991, a policy of partial price disequalization was launched involving freeing-up of prices fixed by distributors and the setting of maximum prices by city for consumers of gasoline, diesel and alcohol, with prices ex secondary distribution bases maintained uniform. It is essential to continue this process to ensure the prices paid by consumers reflect the transportation cost for the fuels.

14. **Alcohol Fuels Subsidies and Pricing:** Anhydrous and hydrated alcohol are used as fuels in Brazil. Anhydrous alcohol, which is eventually mixed with gasoline, is bought by PETROBRAS from producers and sold to distribution companies at gasoline price. Hydrated alcohol, which is used directly in engines, is bought by distribution companies from PETROBRAS or producers at 75% of gasoline price to ensure its competitivity. With this system, prices of alcohol fuels do not reflect the real purchase price from producers. The differences are compensated by an equalization fund (FUPA) which covers transport costs of alcohol over the whole country to ensure a uniform price in secondary distribution bases and the cost of formation and maintenance of alcohol stocks by PETROBRAS. The compensation of FUPA expenses is made to PETROBRAS and

the distribution companies through the Conta Alcohol, and results in two types of subsidies: (i) from consumers of anhydrous alcohol to consumers of hydrated alcohol, (ii) from consumers of anhydrous alcohol close to supply sources to other remote consumers.

15. The system of petroleum products and alcohol prices suffers the following drawbacks:

(i) Cross subsidies are measured against a uniform value of petroleum products (uniform VMR), ignoring the fact that the intrinsic value of these products ex refinery is reflected by international prices. This gives a distorted view of the real economic subsidies applied to petroleum products, and provides the refining sector with a distorted signal concerning the investments required to improve real product valorization and refinery profitability.

(ii) The direct subsidy corresponding to the difference between cost of imported and domestic crude oil (accounted for in "Conta Petroleo") has two consequences. It lowers the average price of refined products and maintains them below their economic prices, and because the Government has not been refunding the difference, also reduces PETROBRAS refining profitability and its capacity to invest.

16. **Recommendations for Petroleum Products Price Reform:** The highest priority is the *full deregulation of petroleum product prices which needs to be implemented as quickly as possible*. This will require the following actions for which Constitutional Amendment No. 9 has removed the constitutional barriers:

(i) Revise the reference scale for ex refinery prices, replacing the value of products realization prices by a set of ex-refinery prices in line with international prices (import or export parity border price based on US Gulf). This would lead to a true appreciation of petroleum product subsidies and their correction.

(ii) Eliminate the crude oil subsidy. This means an increase in the general level of petroleum product prices to bring them in line with economic prices. This will allow ex-refinery prices excluding tax of all petroleum products to be set at parity with their economic prices.

(iii) Eliminate the cross subsidies (including differential taxation distortions) applied to products in competition with natural gas. This means price adjustments which may be compensated by a direct temporary subsidy to consumers where appropriate for social reasons, as is already applied for consumers of LPG. The fuels taxation system should not unduly penalize any single fuel, including natural gas.

(iv) Free up the imports and exports of petroleum products allowing access by independent importers and exporters to the liquid fuels distribution infrastructure. This is necessary for the deregulation of petroleum product prices.

(v) Consider the application of a tax to all hydrocarbon fuels to reflect their propensity to pollute.

Natural Gas Pricing

17. The price of gas to consumers may be set at a level which reflects the cost of supply (*cost of service approach),* which is most appropriate for countries with a permanent excess supply of gas that cannot be exported, and gas prices can be set according to the Long Run Marginal Cost of supply with a depletion fee added to reflect the opportunity cost of using the resource today rather than saving it for the future and which represents the lower limit to prices. Alternatively, the price of gas can be set at a level which reflects the value of gas in end use (*market price approach)* which represents the upper limit. This approach is appropriate in countries where natural gas imports are needed to meet the demand, such as Brazil, because it encourages the most economically efficient use of natural gas and competing fuels, and is more suited to markets in their developmental phase in order to fully exploit the competitively of gas against alternative fuels.

18. **Existing Gas Pricing Structure:** The current system of natural gas pricing does not reflect the principles of efficient gas pricing. Bulk supply prices from PETROBRAS to the distribution companies are fixed by DNC through Portaria. Until now, the PETROBRAS gas supply contracts to the distribution companies did not specify a base price with price indexation formulae and revision clauses, nor equitable take or pay conditions. There remains a lack of a clear gas pricing policy in Brazil, notably for domestically produced gas in relation to Bolivian gas, and how to account for distance related components in the cost of supply. In delineating this issue, it is important to recognize three basic requirements: (i) the gas sales price at the various commercial interfaces should reflect of the netback values of gas in the market, (ii) where the true cost of gas supply to consumers exceeds the netback value of gas in end use, this represents an uneconomic supply option, and (iii) cross subsidies on gas transportation should be avoided whenever possible.

19. **Pricing of Domestic Gas Production:** Domestic gas will have to compete in the same market as Bolivian gas. When the prices of competing fuels are freed and assuming they will not be subject to arbitrary manipulation, the conditions for *interfuel competition* will be created and domestic gas producer prices can be allowed to find their own level in a competitive market, netted back from the value in the market. A share of the economic rent (excess profit for the producer) can be captured by Government through tax However, there is now an opportunity to develop *gas to gas competition*[1], which if

[1] *Gas to Gas Competition* - Where gas producers compete with each other and with gas importers in the same markets for natural gas.

proactively encouraged will be the major driving force to reduce gas production costs and lead to gains in sector efficiency in Brazil. Two conditions are necessary for gas to gas competition to develop, which are: (i) sufficient prospective areas need to be developed by a number of independent producers so that the dominance of PETROBRAS as a gas producer is reduced; and (ii) open access to the gas transmission pipelines is essential to create the mechanism for price competition between gas producers and between gas producers gas importers. These are discussed further below.

20. **Gas Transportation Tariffs:** The Bolivian pipeline project has the characteristics of a natural monopoly and therefore transportation tariffs, which are linked to fixed investments in infrastructure, are subject to price regulation. The purchase cost of Bolivian gas is linked in the supply contract to the international price of fuel oil, and the sale of gas, while not completely subject to free inter fuel competition today, does not necessarily require price regulation for non-captive consumers in the future. For these reasons the gas transport and gas commodity elements for Bolivian gas should be separated.

21. The pipeline transport tariffs should comprise a formula with two components. The *capacity charge* will cover the fixed costs involved in pipeline investment and operation, and reflects the long run marginal cost (LRMC). The *variable charge* is linked to the volume of gas actually purchased, and reflects short run marginal cost (SRMC). Transmission investment is a function of peak utilization where peak consumers bear all the capacity costs, with off-peak consumers exempted. The consumers which do not reserve a capacity on the system (interruptible consumers) should only be charged what is essentially a variable unit charge.

22. Transportation distance and therefore geographic location is a major component of transport cost. The GOB has agreed to provide gas to all the states along the Bolivian pipeline at a uniform city gate price. Projections suggest that those markets off the main trunkline in Sao Paulo and to Curitiba could absorb all the gas in the Bolivian contract, particularly if large scale gas-fired power generation are constructed in Sao Paulo. In this case, the economic cost of gas transport for Bolivian gas to the southern states is the *average* cost of transport in the main trunk line plus the *incremental* cost of the branch line to Porto Alegre. This approach would lead to an average economic cost for Bolivian gas (ex transmission) of about US$2.3/MMBTU along the main trunk line as far as Curitiba, including commodity and transport. When the cost of industrial distribution networks is added on, the final cost of gas to the consumer would be competitive with the economic netback value of gas in end use in key markets such as Sao Paulo, even against the lower value uses where high sulfur fuel is displaced[2]. It is noted that the environmental costs of burning fuel oil are not internalized in the price structure, and an environmental tax on sulfur content would improve the economic competitivity of natural gas, particularly against the high sulfur grades of fuel oil. For the states south of Curitiba, the true economic cost of Bolivian gas incurs an additional average transport cost of about

[2] Current prices for 1A and 3A HSFO are 3.1 and 2.9 US$/MMBTU respectively.

US$1/MMBTU to cover the marginal cost of the southern leg, resulting in an average ex-transmission economic gas cost of about US$3.4/MMBTU. Where Bolivian gas displaces high cost alternative fuels currently used in the special process industries in the southern states, the economic cost of gas supply is likely to be competitive with the economic netback value in end use. On the other hand, where gas is competing with fuel oil in these southern markets, the economic cost of Bolivian gas is likely make competition against fuel oil difficult.

23. The delivered cost of domestically produced gas is lower than Bolivian gas since the transportation distances from the source to the market are much lower. The economic cost of domestic gas production is not known with accuracy, but an indicative production cost in 1995 is estimated at US$1.34/MMBTU which includes a depletion allowance of US$0.34/MMBTU. Therefore, there is a greater margin for the delivered price of domestic gas to be competitive in the markets of the S-SE than Bolivian gas. However, the same fundamental pricing principle applies equally to domestic and Bolivian gas, that the price of gas at the commercial interfaces should be netted back from the value of gas in the market, and that if the cost of production plus transportation of domestic gas exceeds the netback value of gas at any point in the supply chain, then the supply option is uneconomic.

24. The process of geographical disequalization of petroleum fuels and electricity prices has already started, and the eventual goal should be to have gas transport tariffs bear a relation to transport distance to avoid uneconomic fuels purchase decisions. However, in the developmental phase, an initial step could be a system based on a degree of disequalization of transport tariffs using the concept of trunk line and branches, with a single regional transport tariffs for the main trunk line to Sao Paulo (or to Curitiba), and regional transport tariffs the southern and northern branch systems. Systems of distance-based tariffs are in operation in many progressive gas industries worldwide, and the key requirement is to have the transparent separation of the gas price into the components of gas commodity and gas transport, with the gas transport component bearing a relationship to transportation distance.

25. **Pricing of Gas to LDC's and Industrial Consumers:** The gas price from the transmission company to the LDC's and very large industrial consumers should comprise separate capacity and commodity elements. Subject to take or pay commitments, this allows large customers with the option to switch to alternative fuels to make correct fuel purchase decisions, and is required if open access gas transportation services are to be available for third parties.

26. In order to encourage economically efficient expansion of natural gas distribution and utilization activities, for the LDC's and very large industrial consumers it is appropriate for the seller and buyer to negotiate on gas price, taking account of the pattern of alternative fuels usage. Here, the gas price would incorporate a capacity charge and a variable charge. The capacity charge would cover the whole infrastructure required to deliver gas to the consumer, including the transmission fee, pressure reducing and

metering stations and distribution systems as appropriate according to the principles of peak load pricing. The variable charge would be separated into the variable operating costs and the gas commodity charge, and the commodity charge could be pegged to competing fuels through simple indexation. The exact indexation mechanism used would be left to negotiation between buyer and seller, with the gas final price reflecting the value of gas in end use.

27. The gas supply contracts under negotiation between PETROBRAS and the States for Bolivian gas are expected to reflect the sharing of take or pay obligations and price risks which are standard international practice with modern gas supply contracts, with the gas price linked to the international price of basket of fuel oils. While this is a step in the right direction, it is better that the gas price in the sales contracts be set to reflect the netback value of gas in the end use market less the costs of gas distribution, which is consistent with the principles of market based pricing. This might lead to some differences in gas price to the individual states.

28. **Pricing of Gas from LDC's to Residential and Commercial Consumers:** A tariffication system for residential and commercial consumers based on binomial tariffs involves a fixed charge destined to recover the fixed costs associated with the customer's use of the distribution system, and a variable charge proportional to the volume consumed, and presents advantages over the block formulae traditionally used by COMGAS and CEG. In 1994 COMGAS switched to a two-part tariff system, and it is recommended that the distribution companies in process of setting up to take Bolivian gas also adopt the two-part system.

29. **Pricing of Gas to Power Generation:** The price of gas has to reflect its true economic value onto the power generation system, considering future long term development of the system and the implications on the Long Run Marginal Cost (LRMC) of electricity produced. ELETROBRAS' latest planning exercise (1995), the Plano Decenal for 1995-2003, estimates the LRMC for the S-SE and Central West System as US$39/MWh. The rigorous economic evaluation of gas use in combined cycle plants, operating in *complementarity mode* to hydro power (with the gas-fired plant playing a role analogous to a reservoir) requires specific study using a system simulation model of hydro and thermal generation. If operated in complementarity mode, the gas price has also to take account of supply-load constraints imposed on the gas transmission system, and contracts for gas supply to power plants should include capacity charges calculated according to the impact of peak gas utilization on the pipeline infrastructure.

30. ELETROBRAS, in co-operation with the World Bank, has prepared an evaluation of the viability of using gas in thermal power plants in South -South East Brazil. The preliminary results indicate that large new increments of gas fired thermal generation would prove economic when working within the existing hydro system. As an initial step, ELETROBRAS has included 2,200 MW of new gas fired capacity in the S-SE by 2005 in the 1996 Plano Decenal. These results assume that the generator would be obliged to take volumes of gas from the pipeline company equivalent to base load operation, although

under favorable hydrological conditions the thermal power plants could be required to operate far from base load to avoid the spillage of water. In this case, the power producer will need to confirm a secondary market for natural gas to ensure all contracted gas can be sold under all circumstances. Implementation of these projects would be equivalent to a gas demand of perhaps 4 MMCMD by the year 2000, and will lead to a substantial lowering of the average cost of gas transportation if additional gas becomes available via Bolivia to supply the plants.

31. **Recommendations for Natural Gas Price Reform:** Improvements in the establishment of transaction prices between producer, transporter and distribution companies would include the following measures:

(i) Ensure the gas pricing framework is based on the system of market based pricing.

(ii) For domestic gas, the existing production price and transport price should be separated. PETROBRAS should establish separate business areas for gas production and transport with separate accounting;

(iii) If exploration and production can be proactively opened up to private sector and open access for gas importers and domestic producers is implemented, producer prices need not be regulated. Until this happens, the maximum producer price of domestic gas can be set at a level which is netted back from its value in the market, and linked in price to the international price of a basket of displaced fuels, with a share of the economic rent at the producer level captured by GOB through tax.

(iv) For bulk gas supply to distribution companies and very large consumers, separate the gas purchase price and transport price in supply contracts. The transport tariff should be based on a capacity charge proportional to participation in peak utilization of transport infrastructure, and a variable charge related to the volume of gas sold. The main component of the variable charge is the cost of the gas (the commodity) for which the price should take account of the fuels displaced in the market.

(v) Establish gas purchase contracts between gas producer, gas transport company and distribution companies or very large industrial consumers, which contain all the provisions for sharing the constraints between seller and buyer, including take or pay clauses, price indexation formulae and revision clauses.

(vi) Consider basing gas transport tariffs on the concept of trunk line and branches, with a single regional transport tariffs for the main trunk line, and an additional single regional transport tariff for each of the southern and northern systems.

(vii) Establish retail prices based on binomial formulae for residential, commercial and industrial customers of distribution companies.

Gas Sector Structure and Regulation

32. In 1994 the Brazilian gas sector faced a number of strategic options concerning the structural development of the gas industry, and which would depend on the outcome of the constitutional review. The World Bank analyzed these in terms of three options:

Option 1 - No Change: This option assumed *no change* in the Constitution with respect to retention of the PETROBRAS monopoly on import, exploration, production, transport and export of natural gas and competing fuels, with the State Distribution Companies retaining their monopolies on gas distribution.

Option 2 - Relinquishment of Monopolies on Gas: This option assumed that monopolies on gas for PETROBRAS and the State Distribution Companies would be relinquished, with retention of the monopolies on oil and petroleum products.

Option 3 - Relinquishment of All Monopolies on Oil and Gas: This assumed relinquishment of all monopolies on oil and gas, including import, export and inland transportation of natural gas, oil and petroleum products.

33. The characteristics of each option are described in the report. The Constitutional Amendment No. 9 (November 9, 1995) allows the Federal Government to contract state-owned and private companies for the activities related to the petroleum monopoly, including the research or exploration and prospecting or production of the oil reserves, natural gas and other fluid hydrocarbons; the refining of Brazilian and foreign petroleum; the importation and exportation of crude petroleum and basic petroleum derivatives, as well as transportation, by means of a conduit, of crude petroleum, its derivatives, and natural gas of any origin. The Amendment therefore coincides with ***Option 3*** above. Although the Amendment is vague on the issue of imports of natural gas, it is understood that its spirit is to permit natural gas imports by private and state entities. There is now an opportunity to prepare an industry structure which will encourage private sector investment and lead to the development of an efficient gas industry through the introduction of free *interfuel competition* and ultimately *gas to gas competition*. However, the GOB will need to take the following actions if Brazil is to benefit from this potential:

(i) Ex-refinery prices of petroleum products in Brazil to be deregulated as a priority (see above). This will create stable conditions for *interfuel competition* where natural gas will have to compete in the market with alternative fuels which follow international prices.

(ii) Ensure that independent gas producers and importers are allowed Open Access to the Bolivia - Brazil pipeline for the spare capacity over the 8-16 MMCMD under the existing contract, and to the existing PETROBRAS gas transmission infrastructure where spare capacity exists. For future regional gas transmission lines within Brazil, if the developer chooses to construct excess capacity in the pipeline, then this excess capacity should be open for access to third parties under contract carriage terms which ensure the economic viability of pipeline transport operations. These obligations to make spare capacity available to open access will need to be included in the Legislation and strongly enforced by the regulatory agency. This is essential for the development of *gas to gas competition* which will create the mechanism for price competition between domestic gas producers in Brazil, and between domestic gas producers in Brazil and gas importers. Open Access to gas transmission systems and private participation in upstream development will be a major driving force to control extraction costs and lead to increased supplies of domestic gas in Brazil, and will ultimately allow the development of gas to gas competition at the consumer level, by allowing *very* large consumers (such as power stations) and LDC's the option to negotiate directly with a variety of producers and importers for the best commercial terms. This environment will encourage investors in upstream and downstream development in Brazil.

(iii) The active promotion of good prospective acreages for international competition and reduction of the dominance of PETROBRAS in domestic gas production, is essential if meaningful gas to gas competition is to be introduced. These acreages may include new exploration blocks and also areas currently under exploration concession to PETROBRAS but which the company does not have the financial or human resources to develop. If only areas of high technical risk are made available, given the relatively high commercial costs and risks in Brazil, the investor's appetite for technical risk is greatly diminished. If gas to gas competition in domestic production is to be established the near term, the quickest way would be for PETROBRAS to divest itself of some of the existing gas production facilities in S-SE Brazil. In any event, the preparation of a model upstream concession agreement which contains all the necessary contractual, legal, financial and commercial policy details is needed, and any existing geological and seismic data for the allowed drilling acreages should be made available to potential investors.

34. At an early stage of the gas industry development, concession areas for distributors will have to be defined. In an undeveloped market, potential investors in distribution systems will take into consideration (a) whether gas consumers have a right to connect directly to the gas transmission network after the LDC's have already invested in networks to serve them; and (b) if gas consumers can buy gas (the commodity) directly from

producers after the LDC's have entered into take or pay contracts with PETROBRAS. In a situation characterized by limited competition with partial or total vertical integration, where there is an obligation to supply the smaller less profitable consumers, the investors will probably aim to protect themselves against the risks that the supplier will skim off the most profitable consumers through unfair discrimination in prices or supply conditions. Here, the investors may seek territorial exclusivity and resist the right of by-pass for a period sufficient to realize a return their investments. However, it is noted that PETROBRAS on the one hand has a vested interest to ensure that all gas supplied from the import pipeline to LDC's is absorbed in the market to maintain the financial stability of the gas import project. On the other hand, PETROBRAS is currently seeking to expand its distribution activities and could be expected to pursue opportunities to directly connect up to supply profitable consumers. The detailed regulations will need to be developed at an early stage to take account of these issues. Whichever way these regulations are formulated with respect to creating competitive tensions in gas distribution activities (such as the possibilitiy of bypass for very large consumers or the possibility to use distribution transportation services only), it is essential they include a mechanism which ensures that the distribution cost of service offered to all consumers is consistent with efficient distribution operations. They should also avoid to create a controlling interest by PETROBRAS in gas distribution systems as this would reinforce their already dominant position in the gas chain. PETROBRAS will remain the dominant supplier of natural gas to the LDC's for some time to come and gas to gas competition will be weak. However, as soon as the prices of petroleum products are freed, the non-captive consumers of the LDC's will benefit from free interfuel competition since they are able in most cases to switch to alternative fuels if they see a commercial benefit.

35. The re-negotiated agreement with YPFB gives PETROBRAS the option to purchase, in preference to third parties, volumes of gas up to 30 MMCMD of Bolivian gas. There is no good reason for PETROBRAS to retain this exclusive option and very large consumers and LDC's in Brazil should have the opportunity to purchase volumes over and above the 8-16 MMCMD contract quantities directly from producers in Bolivia, or PETROBRAS, or independent producers in Brazil.

36. **Gas Sector Regulation:** It is recommended to set up a regulatory system for gas comprising the following principal components

(i) A comprehensive Gas Act (or Hydrocarbon Law);

(ii) Subordinate legislation comprising rules and regulations on matters mentioned in the Gas Act;

(iii) A model license (or concession or authorization) to transport or distribute gas which contains specific conditions to be fulfilled by the licensee company or companies;

(iv) A code of practice which stipulates standards of safety, performance and service;

(v) A regulation providing for the funding of the regulatory agencies;

(vi) A regulation stipulating the responsibilities for granting concessions.

It is also recommended to:

(vii) Award distribution concessions through a system of open bidding;

(viii) Establish a system of open access for the gas transportation function, with mutual exclusivity of gas transportation and merchant functions for the Bolivia-Brazil pipeline.

37. The Gas Act for Brazil would include matters requiring the approval of Congress, while providing for delegation of authority in specific matters to the appropriate Ministry and regulatory agencies. A regulatory body to be created whose responsibilities would be specified in the Gas Act. The regulatory body would be independent from Government, and not subject to pressures to set prices as a tool to fight inflation, nor to privilege state-owned enterprises, nor to establish cross-subsidies to pursue social goals. Preferably, the regulatory body would comprise a Board headed by a president who would have to be approved by Congress. The members of the board should have fixed terms, without the possibly of removal from office unless found guilty of misconduct. The decisions of the board would be adopted through simple majority.

38. With respect to item (vii) above, the Concession Law for Public Services now requires that new gas distribution concessions be awarded under competitive bidding process.

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1. ENERGY SECTOR OVERVIEW

A. Introduction

1.1 In February 1993, PETROBRAS, Brazil's National oil and gas company, signed an agreement with its counterpart in Bolivia (*Yacimientos Petroliferos Fiscales Bolivianos* - YPFB) for the importation of substantial volumes of natural gas commencing in 1997. This will require the construction of a major import pipeline with natural gas transport and distribution facilities within Brazil, costing several billion US dollars. Implementation of the project presents an opportunity for Brazil to diversify its hydrocarbon fuel sources and increase the share of natural gas in its primary energy supply from 2% to about 10%. This could have a number of desirable effects which include the amelioration of atmospheric pollution though the displacement of less clean fuels in some of the major cities, the provision of gas supplies to the large ceramics industries which currently depend on expensive alternative fuels, the opening of possibilities to construct gas-fired combined cycle power plants to supplement the country's expensive hydro-dominated system, and the industrial stimulus that would be associated with such a project.

B. Organization of the Energy Sector

1.2 The Federal Government has played a pervasive role in the energy sector, owning the energy reserves and associated infrastructure and controlling investment. It has also dictated energy pricing policy and appointed senior management in the sector monopolies. The Federal Government offices charged with the responsibility of regulating the oil and gas sector are: (i) the Ministry of Mines and Energy (MME), and (ii) the Ministry of Finance (MOF). The MME, through the National Secretariat of Energy, has responsibilities which include the formulation and implementation of the national energy policy, and to guide the activities related to PETROBRAS. This mandate is carried out by the *Departamento Nacional de Combustiveis* (DNC) which is under the National Secretariat of Energy, and is the regulatory agency of the oil and gas sector. DNC authorizes allocation of supply and proposes price increases of oil products and bulk supplies of natural gas. The Ministry of Finance, through their Secretariat of Economic Policy, has the final say in price and tariff increases of public and administrated goods.

1.3 The Federal Government has, through the Constitution, the national monopoly for exploration, production, import, export and bulk transport of petroleum, petroleum products and natural gas. The monopoly was devolved to PETROBRAS in 1985 through the law which created the company, and PETROBRAS has been able to fully exercise its monopoly powers. In oil and gas operations, the only areas where other entities have had substantial involvement are at the retail distribution level. For distribution of petroleum products, private sector have about 65% market share with the remainder taken by the PETROBRAS subsidiary, BR-*Distribuidora*. Retail distribution

of LPG is all private sector. For natural gas distribution, the Constitution gave the monopoly to the individual States. There are two large established state owned gas distribution companies operating in Brazil, which are CEG in Rio de Janeiro and COMGAS in Sao Paulo.

1.4 On November 9 1995, the Constitutional Amendment No. 9 was enacted which confers powers on the Federal Government to contract state-owned and private companies for the activities related to the petroleum monopoly, and covers the research or exploration and prospecting or production of the oil reserves, including natural gas and other fluid hydrocarbons; the refining of Brazilian and foreign petroleum; the importation and exportation of crude petroleum and basic petroleum derivatives, as well as transportation, by means of a conduit, of crude petroleum, its derivatives, and natural gas of any origin. In addition, a General Concession Law for Public Services was approved by the National Congress on July 7, 1995. This requires that all concessions for public services (which include gas distribution) must be awarded under a competitive bidding process. These two events have improved the climate for private sector investment in Brazil's oil and gas sector.

1.5 In the power sector, ELETROBRAS, the Federal electric holding company, provides about half of the generation, most of the high voltage transmission and some distribution to large industrial consumers. It has four regional subsidiaries: CHESF for the Northeast region, ELECTRONORTE for the North, ELECTROSUL for South, and FURNAS for the SouthEast. There are some state controlled power generation companies in the large states, and almost all power distribution is made by state companies. Private sector participation has been limited to some electric distribution utilities. The National Secretariat of Energy under the MME has responsibility to oversee, supervise and control the activities related of the Federal Union in hydroelectric matters and the use of hydro resources as well as promulgating norms for power tariff setting.

1.6 A law was passed on July 7 1995 which, in conjunction with the General Concession Law noted above, delegates the Constitutional authority to provide services to private investors and provides for unbundling of the electricity industry by introducing the principle of Third Party Access. The new legislation also abolished the traditional rate of return based electricity pricing; under current legislation, prices are expected to be based on ad-hoc contractual arrangements resulting from the process of bidding for concessions. In addition, the GOB has recently announced its intention to sell at least its controlling shares in some of the major utilities, allowing the private sector to build new power plants and participate more intensively in distribution activities throughout the country.

C. Energy Resources and Consumption

Primary Energy

1.7 Brazil is endowed with substantial energy resources as shown in Table 1.1. Proven resources of fossil fuels are estimated at about 3,300 million tons of oil equivalent (MTOE) which comprise about 77% coal, 17% oil and 4% natural gas. In addition, there are large reserves of shale oils and gases which, although not properly evaluated, are believed to be of similar size to the proven reserves of oil and natural gas.

Table 1.1: Brazil-Proven Energy Resources

	Specific Unit	MTOE
Natural Gas	146 BCM	124
Oil	659 MMCM	575
Coal	10,157 MMT	2,566
Peat	129 MMT	40
Hydro (firm)	82.7 Gw y	210/y

Source: National Energy Balance-1994

1.8 Proven reserves of natural gas in were 146 BCM in 1994 and 154 BCM in 1995. The reserves offshore Rio de Janeiro are 63 BCM which is almost all associated gas, and account for almost 40% of the nation's total. About 5.5 BCM of non-associated gas are located offshore Sao Paulo. Bahia and the Amazonian basin together hold a further 40%. About 70% of proven gas reserves are associated with oil. Taken together, the proven, probable and possible categories could increase the natural gas reserve base to about 230 BCM. Proven reserves of oil increased from about 659 MMCM in 1994 to about 760 MMCM in 1995.

1.9 Domestic production and imports of primary energy are shown in Table 1.2, and the National Energy Balance is presented in Annex 1.1. These show that hydropower accounts for about one-third of primary energy. Petroleum also provides almost one third of primary energy with about half supplied from domestic oil and the rest from imported crude. The remaining supplies of primary energy were derived mainly from wood and sugar cane derivatives. Natural gas, when adjusted for reinjection and losses, contributes only 2% to the country's primary energy supplies.

Table 1.2: Primary Energy Supply and Consumption

	Unit	Domestic Production (unit/y)	Domestic Production (10 3 TOE)	Net Imports (unit/y)	Net Imports (10 3 TOE)
Natural Gas	BCM	8.8	7,508	-	
Petroleum	MMCM	38.7	33,803	32.0	27,918
Coal	MMT	6.9	1,980	11.4	8,370
Hydropower	Gwh	243	70,446	-	
Wood	MMT	78.8	24,110	-	
Cane Baggase	MMT	102.1	21,,357	-	
Other			3,105		
TOTAL			162,309		36,288

Source: National Energy Balance-1994

The Supply and Demand of Petroleum Products

1.10 The prospects for the development of the natural gas sector in Brazil are influenced by the availability of liquid hydrocarbon fuels which compete with gas. Table 1.3 shows the domestic production, consumption and surplus (or deficit) of the most important products.

1.11 Consumption of LPG has grown rapidly throughout the past decade, and since 1985 imports have roughly tripled to more than 2 MMCMY. Subsidized prices were the principal cause of high demand, particularly for residential consumers where LPG represents the major competitor to natural gas. Low prices for LPG relative to gasoline have encouraged its use as an automotive fuel and an illegal cross-border trade in bottled LPG. Over the last two years, LPG prices have increased close to international prices.

1.12 Domestic consumption of gasoline and alcohol are closely linked since gasoline is displaced by alcohol in the domestic automotive market. In 1980, Brazil's consumption of gasoline and alcohol were about 11.5 and 3.2 MMCMY respectively, with only a small exportable surplus of gasoline. In 1991, and with the expansion of the alcohol program, the consumption of these products reached 10.3 and 12.5 MMCMY respectively. Over this period, Brazil's gasoline export market switched from Africa and Latin America to the United States, which takes about 90% of total gasoline exports of about 3 MMCMY

1.13 Diesel oil is the major petroleum derivative consumed in Brazil and is the overriding factor which determines the level of domestic refining. Domestic consumption progressively increased from about 20 MMCMY in 1985 to about 26 MMCMY in 1995, and demand is expected to increase further. It has been necessary to progressively increase the level of imports to meet demand, and it is envisaged that large investments will be required to increase the yield of diesel from domestically refined crude.

1.14 The domestic consumption of fuel oil has risen from about 10 MMCMY in 1990 to about 12 MMCMY in 1995. In 1994 the difference between domestic production and

consumption of fuel oil was 1 MMCMY (in excess). However, increasing supplies from the domestic Marlim and Albacora fields, which contain about 30% fraction of heavy products and vacuum residues, would result in a larger net surplus of fuel oil. This will need to be exported or upgraded into lighter products through new refinery projects in Brazil.

Table 1.3: Petroleum Products Production and Consumption

	Domestic Production (MMCMY)	Domestic Consumption (MMCMY)	Surplus* (Deficit) (MMCMY)
Diesel Oil	25.5	27.5	(2.0)
LPG	7.8	10.0	(2.2)
Fuel Oil	11.7	10.7	1.0
Gasoline	15.0	11.7	3.3
Kerosene	3.0	2.7	0.3
Naphtha	5.4	8.0	(2.6)
Alcohol	12.1	12.9	(0.8)

Source: National Energy Balance-1994
*Actual Volumes of Imports or Exports May Differ due to Stock Changes

D. Gas Sector Issues

1.15 The efficient development of Brazil's natural gas sector, both through the further utilization of domestic gas resources and the importation of Bolivian gas, is dependent on the resolution of the following issues:

(i) Brazil's refinery structure does not allow a high overall degree of conversion and results in an exportable surplus of fuel oil. Investments are needed in refinery upgrading primarily to increase the yields of light ends, particularly diesel oil. This would reduce the yields of the heavier products which in turn affects the prospects for the market penetration of natural gas.

(ii) Gas use for large increments of power generation could lessen the risk of low market take-up in the early years of the expansion of Brazil's gas industry. There has been much uncertainty regarding the economic and financial viability of base load thermal power in South-South East Brazil, particularly in view of the requirement to operate in complementarity to hydropower.

(iii) Price distortions and subsidies on those fuels in competition with natural gas have been prevalent over recent years. To encourage economically viable development of the gas sector, it is essential that a program for price rationalization is established, and that a regulatory framework is put in place which clearly establishes the rules for the long term.

(iv) Gas sector development in Brazil will need a large influx of domestic and foreign private sector capital. The prospects for this will improve if gas is allowed to compete with alternative fuels without the possibility of arbitrary price interventions, if economic supplies of natural gas can be assured, and if a satisfactory and transparent regulatory framework is established.

1.16 In view of these issues, the specific objectives of the study were to:

(i) Identify the price subsidies and economic distortions for natural gas and its competing fuels and propose priorities for price rationalization.

(ii) Identify the most appropriate framework within which to price natural gas, taking account of the various approaches to the structure of tariffs.

(iii) Identify alternative legal and regulatory frameworks for the natural gas sector which may be feasible in view of the outcome of the constitutional review.

(iv) Propose alternatives, identifying their advantages and disadvantages, for regulatory bodies which may oversee the development of the gas sector.

2. NATURAL GAS SUPPLY AND DEMAND

A. Introduction

2.1 Since 1990 there have been several studies made concerning the prospects for the supply and demand for natural gas in Brazil. In 1992, the Infragas group, which represents industrial interests in Santa Catarina, Parana, and Rio Grande do Sul, commissioned a gas demand study restricted to the three States. In 1993 a study commissioned by *Sociedade Privada de Gas* (SPG) determined the potential demand for gas in the State of Sao Paulo, and a follow up study in 1995 examined the prospects for gas use in power generation in South-South East Brazil. Meanwhile, PETROBRAS assembled its own forecasts of gas demand in the South-South East, and which represent aggregates of data provided by the State Governments. These studies have helped to define the future gas market in Brazil for the industrial and power sectors. Although these studies strongly suggested there would be a large demand for gas in power generation, the issue remained unresolved. Recent studies prepared by ELETROBRAS and the World Bank have confirmed the economic demand for gas fired thermal generation in the South-South East.

2.2 This section summarizes the available data on domestic gas reserves, production prospects and demand, and includes benchmark estimates of the economic cost of gas supply and the value of gas in the various classes of end use, taking account of the likely availability of fuel oil from PETROBRAS refineries and its effect on the opportunity cost of gas.

B. Natural Gas Supply

Domestic Gas Reserves, Production and Supply

2.3 **Domestic Reserves:** The evolution of oil and gas reserves in Brazil is shown in Annex 2.1, Fig. 1. As of December 1995, proven reserves of natural gas were officially estimated by PETROBRAS at 154 BCM, and have about doubled over the last ten years. About half the proven gas reserves are located offshore, with about 60% being in the form of associated gas. However, it is noted that there has not been an independent audit of Brazil's gas reserves in recent years. The total volume of proven, probable and possible reserves now amounts to about 230 BCM, but expectations of new discoveries could add a further 147 BCM. After excluding flaring and gas used by PETROBRAS own use for re-injection and treatment, this would leave about 258 BCM available for sale between 1993 to 2015.

2.4 The geographical distribution of gas reserves is shown in Table 2.1. The South-South. East region, including the states of Rio de Janeiro, Sao Paulo and Parana, have the largest expectations in terms of probable reserves and new discoveries (95% being offshore).

2.5 **Domestic Production and Sales:** Natural gas production has increased from 8.3 MMCMD in 1993 to 21.8 MMCMD in 1995, 72% of which is associated gas (Annex 2.1, Fig 2). However, only about 40% of this volume is available for sale, of which 8% is used for petrochemicals, 2% for automotive use, 5% for residential use. About 66% is used as fuel and 15% as fertilizer feedstock. Of the total gas produced, about 18% is lost or flared, with the remainder used for reinjection and PETROBRAS' own consumption.

Table 2.1 Geographical Distribution of Gas Reserves -1993*
(BCM)

	Proven Reserves	Total Reserves	New Discoveries	Available for Sale to 2010
Amazonas	20	45	19.3	44.6
North East	57	76	34.2	68.6
South - S.East	60	94	93.6	145.6
TOTAL	137	215	147.2	258.7

Source: Provided by PETROBRAS during 1993 Gas Sector Mission
* Proven reserves in 1995 were 154 BCM, and total reserves are estimated at 230 BCM

2.6 PETROBRAS' own estimates of the gas volumes for sale from existing fields and new discoveries both nationally and by region, to the year 2010 are shown in Annex 2.1, Figs 3-8. These suggest that PETROBRAS could increase gas production by about three times the current level by 2001. This is providing sufficient financial resources would be available for exploration and exploitation of new discoveries, although the economic viability at achieving these levels of production are not known. It is noted that an independent audit of gas resources is not available.

2.7 **The Existing Gas Supply System:** There are five separate gas pipeline systems located along the Atlantic coast, and all operated by PETROBRAS:

2.8 *The Ceara System* comprises 56 km of onshore pipeline to transport about 0.2 MMCMD of gas in the Fortaleza area. The system has limited expansion possibilities with only 0.3 BCM of gas available for sale from existing fields and 0.4 BCM expected from new discoveries. *The Rio Grande do Norte System* comprises 654 km of onshore pipeline and transports gas from the offshore field of Ubarana in the state of Rio Grande to Recife. About 6.4 BCM of are available from the existing Ubarana and Agulha fields, and about 16.9 BCM are expected from new discoveries after 1998 from the field of Pescada (free gas). *The Bahia System* originates in the state of Alagoas, and delivers gas to Alagoas, Sergipe and Bahia and on to Salvador through 900 kms of onshore pipelines. The three states together would provide about 28 BCM of gas available for sales from existing fields, and 17 BCM are expected from new discoveries. Gas production from the three states amounts to about 8 MMCMD. *The Espirito Santo System* comprises 205 km of onshore pipeline from Sao Mateus to Victoria, transporting about 0.63 MMCMD from the field of Caçao. This field would provide 2.4 BCM of gas for sale, with an additional 1 BCM expected from new discoveries.

2.9 *The Rio de Janeiro - Sao Paulo System* connects the offshore gas reserves of Campos and Santos fields to Rio de Janeiro and Greater Sao Paulo through 870 km of onshore pipelines. The total gas production of Campos fields was about 8.7 MMCMD in 1995, of which 1.1 MMCMD was distributed by CEG in Rio de Janeiro and a further 2.5 MMCMD supplied to industrial consumers served direct by PETROBRAS. Gas available for sale from existing fields in Campos would be about 30 BCM with 13 BCM from expected new discoveries over the period 1993-2010. In the Santos basin, the Merluza field came on stream in 1993 to provide additional supplies to COMGAS, and during 1995 supplies distributed by COMGAS reached about 3 MMCMD from both Campos and Santos. The Merluza field would account for 17 BCM of available reserves, corresponding to a production plateau of 2.5 MMCMD. PETROBRAS forecast an additional 26 BCM to be available from new discoveries in the Santos basin.

2.10 The Southern areas of Parana and Santa Catarina area have not yet developed gas pipeline systems, despite high potential demand in the industrial sector. However, PETROBRAS forecasts indicate potential new discoveries amounting to 54 BCM in Bacia de Santos area, suggested by results obtained in offshore pilot production systems of Coral and Estrela de Mar. Although there are as yet no gas transmission systems in the Amazon region, several projects are currently under study, in particular gas transmission to markets of Manaus and Porto Velho by pipeline and as LNG. According to PETROBRAS, existing fields in the Amazon would provide a plateau production of 3 MMCMD until 2005, increasing to 5 MMCMD thereafter. Exploitation of new discoveries could boost production to 6-9 MMCMD, although it is unlikely that any future Amazon gas system would be interconnected with other regions.

Natural Gas Supply through Imports

2.11 ***Bolivia:*** The importation of natural gas from Bolivia has been proposed to commence from 1998/9. In the longer term, additional gas could be obtained from production from new discoveries in Brazil, additional imports from Argentina, or by LNG from Africa or Venezuela.

2.12 An independent reserves and delivery certification study of Bolivian reserves was carried out in 1995 by a reputable international consulting company. This targeted 33 of the largest fields in Bolivia which encompass about 95% of the known reserves. The results showed that, taking account of gas for Bolivia's own use, the economically deliverable reserves in the proven, probable and possible categories at the original contract price agreed between PETROBRAS and YPFB, would be sufficient to meet the supply contract with Brazil in full for at least 10 years with some shortfall thereafter.

2.13. There is good exploration potential for new discoveries in Bolivia with less than 20% of the country having been explored, and if Bolivia continues with the past level of exploration effort, they will be able to build up sufficient reserves to satisfy the contractual demand for Brazil for probably the whole 20 years. PETROBRAS is

confident of future discoveries in Bolivia and Argentina from their own exploration licenses which would ultimately reach the Brazilian market. In spite of this it is expected that: (i) with the exclusion of own use supplies for Bolivia, all proved plus probable reserves will need to be dedicated for Brazil and given priority over export to other countries, and (ii) YPFB's supply obligations to the project will have to be supported by dedicated reserves and these obligations will need to be assumed by the upcoming capitalized companies in Bolivia.

2.14 The preferred pipeline route from Bolivia is the NorthWest route which comprises a 3,110 km pipeline from Santa Cruz in Bolivia to Sao Paulo in Brazil, and continuing south to Porto Allegre. This would connect into the existing PETROBRAS transmission network which currently supplies gas from the Campos and Santos basins to markets in Rio de Janeiro and Sao Paulo. A northern spur recently constructed by PETROBRAS connects Minas Gerais to the gas supply network at Rio de Janeiro. The whole network will cover an area which encompasses 67% of Brazil's economic activity.

2.15 **Argentina:** Total proven reserves of natural gas in Argentina were about 520 BCM in 1994, with 125 BCM located in the North West region. These reserves are well located to supply Southern Brazil direct, or via Bolivia by reversing the flow in the existing Bolivia -Argentina pipeline. The situation in the short term is favorable to such operations, because natural gas reserves in North West Argentina would be better valorized through export, leaving other regions such as Neuquen to supply the internal market. In the short to medium term, the gas available for export could amount to about 8 MMCMD. Since the privatization of the petroleum sector, gas production in Argentina has increased on average by 5-6% per year, to 20% higher than earlier forecasted, due to greater competition between natural gas and fuel oil and which may ultimately effect the volumes of natural gas available for export to Brazil.

2.16 There are several possible routes for export of gas from Argentina to Brazil, which are: (i) gas export from Campos Duran to Bolivia (Santa Cruz de La Sierra) with flow reversal in the existing pipeline, and then on to Sao Paulo via the Northwest route; (ii) the so called Southern route, which would require the construction of a pipeline connecting the provinces of Misiones and Corrientes in Argentina to Rio Grande do Sul in Brazil, with extensions to Parana and Santa Catarina; and (iii) a third possible route would connect Bolivia to Brazil through Paraguay, requiring a 740 km of pipeline in Argentina, 310 km in Paraguay, 540 km in Brazil up to Curitiba, and 380 Km to join Sao Paulo. The option to import Argentinean gas through the interconnecting pipeline with Bolivia may be economically feasible for the medium term, thereby supplementing Bolivian supplies. The Southern route would only be considered for the longer term due to financial constraints.

2.17 **Other Sources:** LNG imports may become a feasible in medium to long term, and although the border price of LNG would be higher than that of pipeline gas from Bolivia and Argentina, there would be less capital investment required in pipelines. LNG

could be imported by Brazil from existing plants in Nigeria and Algeria, or future plants in Venezuela and South Argentina.

Economic Cost of Gas Supply

2.18 The economic cost of gas is based on the gas supply and demand of the South-South East region of Brazil supplied by the Bolivian gas pipeline project, and interconnecting the states of Mato Grosso Do Sul, Sao Paulo, Parana, Santa Catarina, Rio Grande Do Sul, Rio de Janeiro, and Minas Gerais. The economic cost may be calculated over a period of twenty years from 1995 to 2015, considering the four most likely supply sources, namely:

(i) Gas from existing fields, comprising associated gas from Campos fields, and free gas from the Merluza field in Santos basin;

(ii) Gas imported from Bolivia;

(iii) Gas from new discoveries in Brazil; and

(iv) Complementary volumes through additional pipeline supplies from Argentina or as imported LNG.

2.19 The final economic cost of gas will depend on the relative share and cost of each source in the supply mix. The first two sources are practically fixed in terms of expected volume and cost. Gas from new discoveries in Brazil is subject to some uncertainty, but the volume assumptions used by PETROBRAS have been retained. Complementary volumes of gas (the last source), are considered as the backstop fuel, which is the substitute gas which would replace the firm sources of domestic and imported gas when these sources become depleted. The expected cost of this complementary gas is a basic component for calculation of the Depletion Cost.

2.20 The economic cost of gas at wellhead is the sum of two components. These are the Average Incremental Cost (AIC) of gas production which reflects the Long Run Marginal Cost (LRMC), and the Depletion Cost of domestic production.

2.21 **The Average Incremental Cost:** The AIC of domestic gas production in Brazil is not known with a good accuracy. For associated gas, there is no specific accounting in PETROBRAS to allocate the costs incurred in joint production of oil and gas. A review of some past PETROBRAS studies indicates an average wellhead cost of US$ 0.75/MMBTU for associated gas from Campos field. For free gas, development of Merluza field is the sole reference, and a review of available data indicates that the development of Merluza under a risk contract by Pecten-Shell has resulted in untypically high cost, estimated at US$1.3-1.5/MMBTU.

2.22 **The Depletion Cost:** The Depletion Cost is considered as an additional cost which reflects the fact that gas is an exhaustible resource. If gas is used today, at some future date it will become depleted and will have to be replaced by some other resource (such as fuel oil, coal, SNG, or more practically new gas discoveries and LNG import). This alternative resource, or backstop fuel will usually be more expensive. The Depletion Cost is calculated using the "Hotteling rule" and the concept of backstop fuel taking account of the expected depletion profile of domestic gas. According to expected balance between economic demand and supply in the South-South East, domestic gas resources would be depleted by 2010. It would be inappropriate to consider the larger part of the backstop fuel as fuel oil, since fuel oil is unsuitable as a replacement for gas in many applications, and environmental constraints will become more stringent. Instead, it is reasonable to assume that additional gas imports would be sought. However, the precise mix of the replacement fuel at the depletion date, when both domestic gas and import from Bolivia are exhausted is open to debate. However, for this study it has been assumed that the replacement fuel would be pipeline gas imported from Argentina and imported LNG. The Depletion Cost is calculated on the following basis :

(i) The Depletion Cost is applied only to domestic gas (free and associated) and not to gas imported from Bolivia.

(ii) The replacement fuel at depletion date is assumed to be a mix of 50% Argentinean pipeline gas and 50% LNG.

(iii) Argentinean gas has a reference price estimated at around US$1.65/MMBTU at Brazilian border in 1995. Assuming this increases by about 1%/yr. until the depletion date results in a price of US$1.98/MMBTU in 2010.

(iv) LNG imported from Nigeria, Algeria, Venezuela or South Argentina has a reference price regasified on the Brazilian coast of US$3.30/MMBTU in 1995. This would increase by about 1%/yr. until the depletion date, giving US$3.95/MMBTU in 2010. These increases assume that the international transaction price of gas, indexed on a mix of low sulfur fuel oil and gas oil, will roughly follow the price of crude oil.

2.23 At the depletion date (2010), replacement of domestic gas by a 50:50 mix of Argentinean pipeline gas and LNG would result in an average border price of the replacement fuel of US$2.96/MMBTU. If the economic production cost of domestic gas is about US$1.0/MMBTU, this corresponds to an additional cost of US$1.88/MMBTU for the consumer in 2010. This additional cost, when drawn back to 1995 with a discount rate of 12%, is equal to US$0.34/MMBTU. This represents the Depletion Cost to be added to the production cost in 1995, and results in an economic cost of domestic gas of US$1.34/MMBTU in 1995. The Hotteling rule stipulates that the depletion cost rises over time from the initial period (1995) to the depletion date (2010) with an annual growth rate equal to the discount rate (12%). The total average economic cost of gas

supply in 1995 is thus US$1.32/MMBTU, which represents the weighted average cost of Bolivian gas (US$1.30/MMBTU, assuming US$0.9 and US$0.4/MMBTU wellhead and transport cost to the border) and domestic gas (US$ 1.34/MMBTU). The depletion cost component increases over time with a discount rate of 12%, so that at depletion date in 2010, the economic cost of domestic gas is just equal to the price of imported gas and LNG (US$2.96/MMBTU).

2.24 **Economic Cost Profile:** The economic cost profile defined above is thus the weighted sum of three components: (i) the AIC of gas production; (ii) the depletion cost and; (iii) the cost of Bolivian gas. This economic cost profile can be also expressed as a levelised cost over the period 1995 to 2015 (using the discount rate of 12%), which includes the AIC for domestic gas (US$1.00/MMBTU), the average depletion cost for domestic gas (US$1.00/MMBTU), and the average cost for Bolivian gas (US$1.40/MMBTU). This gives an average economic cost of US$1.62/MMBTU. These estimates of the economic cost are approximate and can only be used as a general guide, and are illustrated in Annex 2.2 (Fig. 1) and summarized in Table 2.2 below:

Table 2.2: Profile of Economic Cost of Gas (US$/MMBTU)

	1995	2000	2010	Levelised
AIC Domestic Gas	1.00	1.00	1.00	1.00
Depletion Cost	0.34	0.61	1.88	1.00
Econ. Cost Domestic Gas	1.34	1.61	2.88	2.00
Bolivian Gas (border)	1.30	1.36	1.51	1.40
TOTAL Economic Cost	1.32	1.46	1.98	1.62

Source: World Bank Estimates

C. Natural Gas Demand

2.25 The natural gas demand studies carried out since 1990 identified a "potential market" based on energy consumption in uses open to gas substitution, and an "economic market" assuming gas penetration levels in the various sectors. However, these studies did not take account of the impact of the PETROBRAS refinery upgrading program on the future availability of domestically produced fuel oil, and did not confirm the future demand for gas in power generation.

Demand for Gas and Availability of Competing Fuels

2.26 The future gas demand must take account of the availability and price of petroleum products which will compete with natural gas. In the transport sector, gasoline and diesel oil may be replaced by alcohol and compressed natural gas (CNG). In the residential sector, natural gas competes with LPG and electricity. In the industrial sector, the most critical product in competition with natural gas is fuel oil, which is used in industrial boilers and furnaces. However, increasing environmental constraints will

make the use of high sulfur residual fuel oil increasingly more unacceptable in light and medium sized industries, where it is expensive to install exhaust gas cleanup facilities. Fuel oil may also be used in thermal power plants equipped with exhaust gas cleanup facilities, but it also has to compete with natural gas used in high efficiency combined cycle plants which also minimize environmental damage.

2.27 PETROBRAS' estimates suggest that more than half of the total industrial market for gas could be through displaced fuel oil, which means that the feasibility of the natural gas development program is linked to the solution found for residual fuel oil management in Brazil's oil refineries. The main problem faced by the oil refiners is the "bottom of the barrel" management, where the issue is to find the best solution to utilize or transform excess residual fuel oil. Although the international price of fuel oil has proved difficult to predict over the last few years, it can in general be said that fuel oil export is a poor business.

2.28 **The Refinery Upgrading Program:** The refining sector in Brazil involves a total useful capacity of about 58 MMTY (1.5 million bbl/day), spread over ten main refineries as shown in Annex 2.3 (Table 1). PETROBRAS controls 98% of the total capacity, with the remainder in private hands. These refineries are of low to medium complexity. As shown in Annex 2.3 (Table 2), ten refineries are equipped with catalytic cracking units, representing approximately 26% of the distillation capacity, with only two refineries operating delayed coking units (RPBC and REGAP). This structure results in the products yield pattern shown in Table 2.3, which indicates a high yield of fuel oil.

Table 2.3 Refinery Product Mix

Product	LPG	Gasoline	Naphtha	Kerosene	Diesel	Fuel Oil	Other
(%)	5.3	15.8	9.0	4.5	35.1	19.6	8.4

Source: Provided by PETROBRAS during 1993 Gas Sector Mission

2.29 On average, the refineries are processing a 60:40 mix of domestic and imported crude oil (medium and heavy crudes). The two refineries which are operated to adjust the products supply and demand balance are REVAP, which processes about 70% domestic crude, and REPLAN, which is the most flexible refinery. It is noted that fuel oil produced from domestic crudes has a low sulfur content (about 1wt%). The processing of Marlim crude oil will confirm the trend to low sulfur fuel oil production. Marlim crude is heavy (23 API) with a 60% yield of atmospheric residue and 35% vacuum gas oil used as catalytic cracking feedstock. Production from this field started in 1994, and is expected to reach 6.2 MMCMY in 1996 and 16.5 MMCMY in 2000.

2.30 The program of refinery upgrading to the year 2000 is shown in Annex 2.3, Table 3. This involves revamping and installation of additional catalytic cracking capacity totaling 4 MMTY in the three largest refineries which will process Marlim crude. This will result in increased production of gasoline, LPG, and the low quality diesel oil

component. Additional coking units will allow 3.35 MMTY of heavy residue to be processed. The net result of the program will be to stabilize the production of fuel oil at 14 - 15 MMTY by the year 2000. Additional hydrotreating capacity of 6.3 MMTY will be used mainly to improve diesel oil quality. It is not known if PETROBRAS has the financial resources to fully implement the upgrading program, but the opening up of the refining sector to private investors through the Constitutional Amendment No. 9 has improved the prospects for the implementation of these and other refinery upgrading projects in Brazil.

2.31 **Supply-Demand Projections for Petroleum Products:** Forecasts of petroleum products demand in Brazil are difficult to assess due to uncertainty surrounding future developments of alternative fuels, the continuity of alcohol program, and the extent of natural gas penetration. The PETROBRAS assumptions for the supply and demand of fuel oil are shown in Table 2.4. These take account of the absorption of Bolivian and domestic gas in the market, and show that the effect of the refinery structure adjustment program is only to stabilize the volume of fuel oil produced at about 14.5 MMCMY. This is because the increasing share of heavy crude oils leaves an excess of fuel oil to be exported. However the lower sulfur content of domestic crude would be reflected a low sulfur content of exportable fuel oil in excess by 2000, which opens more profitable opportunities for the fuel oil export business.

Table 2.4 Brazil's Fuel Oil Supply-Demand Balance to 2000 (MMCMY)

Fuel Oil (MMCMY)	1997	2000
Demand	14.32	13.34
Production	14.31	14.54
Import	1.21	-
Export	1.20	1.20

Source: PETROBRAS- 1996

2.32. If the exportable excess of fuel oil can be reduced to being nearly in balance, then this should not present too much of a problem for natural gas penetration, especially if the fuel oil production is predominantly low in sulfur. On the other hand, if the refinery upgrading program is not implemented, the importation of natural gas will exacerbate the fuel oil management problem.

2.33 The PETROBRAS assumptions for LPG supply and demand are shown in Table 2.5, which indicates LPG imports progressively reducing to come into balance by the year 2000.

Table 2.5 LPG Supply-Demand Balance to 2000

LPG(MMCMY)	1994	1997	2000
Demand	9.63	11.35	12.54
Production	6.51	9.60	12.42
Importation	3.12	1.75	0.12

Source: PETROBRAS- 1996

The Value of Gas in End Use

2.34 A prerequisite to the evaluation of competitivity and demand for natural gas is the estimation of the economic and financial value of gas relative to competing fuels in the various end uses, expressed by its netback value or break-even price. Values obtained are a direct function of the economic costs of fuels in competition with gas. In a deregulated fuels price market, the fuels prices will more or less reflect their economic costs. Where gas is in competition with fuel oil, the economic cost of fuel oil is set at export parity if in exportable excess, or at import parity when in deficit.

2.35 Each specific use of natural gas has an associated economic netback value. For illustration, a ranking of the economic netback values of gas in several common uses (at the consumer gate) is shown in Table 2.6. These values are based on the indicative values for economic costs of alternative fuels, and should be taken as a general guide to the economic value of gas in various end uses. Estimates of economic costs of some of the key competing fuels in Brazil in 1995 are shown in Annex 3.4 (Table 2). These show the economic costs for HSFO of US$3.2/MMBTU (imp. parity) and US$2.2/MMBTU (exp.parity), and for LSFO of US$3.7/MMBTU (imp parity) and US$2.6/MMBTU (exp.parity). The 1996 prices of Fuel Oil in Brazil are about US$3.2/MMBTU and US$3.9/MMBTU for HSFO (1A) and LSFO (1B) respectively, which are close to economic prices based on export parity.

2.36 **Residential Sector:** Gas use for cooking and water heating is competitive with electricity and LPG in economic terms due to the high economic cost of these fuels, with economic netback values above US$18/MMBTU. The competitivity is maintained even though gas distribution costs are high, and gas will retain its advantage in the long term due to the high international price of LPG and the high cost of the power generation expansion plan.

2.37 **CNG as Motor Fuel:** This represents a high value use for gas. The netback value of gas is high when it replaces gasoline in taxis at US$6.7/MMBTU. When used as a replacement for alcohol in taxis, the gas netback value is about US$12.5/MMBTU. Replacement of diesel oil in city buses is about US$5.2/MMBTU due to the lower economic cost of diesel oil, but the netback value obtained for dedicated bus engines is about US$5.9/MMBTU. The expected increase in environmental constraints will clearly improve the attractiveness of CNG.

2.38 **The Industrial Sector:** Gas use is highly competitive with diesel oil and LPG where used in thermal operations due to the high economic cost of those fuels. This is also the case where gas replaces wood and charcoal which also have high economic costs of about US$5-6/MMBTU. Gas replacement for fuel oil is more critical because of its lower economic cost. The utilization of gas rather than fuel oil in boilers and furnaces leads to premium factors of 5% to 15% in existing plants with benchmark netback values estimated at US$2.3-3.2/MMBTU where it displaces fuel oil at export parity, and US$3.3-4.2/MMBTU where it displaces fuel oil at import parity. Premium factors are higher in special processes, such as controlled atmosphere furnaces. It is noted that these netback values do not include an environmental premium, which increases the economic netback value of gas where it displaces fuel oil.

Table 2.6 Benchmark Estimates of Netback Value of Gas at Consumer Gate for Typical Uses (US$/MMBTU)

End Use	Economic Netback
Residential[1]	18
CNG (buses)[2]	6
CNG (taxis)	12
Industry (FO)[3]	2.3-3.2
Industry (FO)[4]	3.3-4.2
Cogeneration	3.4 - 4.7
Cement (FO)[5]	2.9-3.2

Source: World Bank Estimates

Footnotes: --- 1 LPG for cooking, Elec. for Water Heating; 2 With CNG dedicated engines; 3 Econ. cost HSFO US$2.2/MMBTU at export parity and LSFO US$2.6/MMBTU; 4 Econ. cost HSFO US$3.2/MMBTU at import parity and LSFO US$3.6/MMBTU; based on HSFO 1A-3A at import parity.

2.39 **Cogeneration:** The economic value of gas in cogeneration systems is a direct function of the cost of electricity and the alternative fuel, usually considered to be fuel oil. Within an environment of electricity prices above US cents 5/Kwh and fuel oil priced at import parity, cogeneration systems based on gas turbines become attractive, with gas netback values of US$3.4-4.7/MMBTU.

2.40 **Cement Manufacture:** Fuel oil accounts for about 50% of the fuel used in Sao Paulo's existing cement plants followed by coal at 42%, and the competition is therefore between fuel oil, coal and natural gas. When in competition with coal for new plants using either the wet or dry process, the gas netback values become quite high (US$3.4-3.8/MMBTU) as soon as the economic price of coal price reaches US$50/ton. The conversion of existing coal plants to gas only becomes attractive when the economic costs of coal are above US$50/ton. When in competition with fuel oil for new plants, the netback value of gas is very close to the price of fuel oil and gas can be economically viable when fuel oil is priced at import parity. However, gas would become more

competitive with fuel oil if the environmental premium on sulfur is internalized in the relative price of fuel oil and natural gas.

Natural Gas Demand Forecasts

2.41 The demand studies carried out to date have focused on the regions expected to be supplied by the Bolivian gas pipeline project, in particular Sao Paulo, Rio de Janeiro and the Southern States of Parana, Santa Catarina, Rio Grande Do Sul, and Minas Gerais.

2.42 These studies all show a consistently large future industrial demand for natural gas in comparison with the likely available supplies. The PETROBRAS industrial gas demand forecasts the South-South East are summarized in Table 2.7. These were based on 1988 market survey data using macroeconomic growth projections with exclusion of low value markets and consumers located far from the Bolivian pipeline route. They show the economic demand for gas increasing to about 44 MMCMD by the year 2000, and to 63 MMCMD by 2005, and exclude several uses including power generation, cement manufacture and some steel production.

Table 2.7 Economic Demand for Natural Gas in Industry for S-South East (MMCMD)

	1996	2000	2005
Mato Grosso de Sul	0.46	3.02	2.96
Minas Gerais	1.15	8.00	10.35
Rio de Janeiro	5.00	7.5	18.00
Sao Paulo	7.50	17.71	20.52
Parana	1.25	2.76	3.85
Santa Catarina	1.70	2.83	3.15
Rio Grande do Sul	1.00	2.53	4.00
TOTAL - MMCMD	18.06	44.35	62.83

Source: PETROBRAS

2.43 During the 1993 gas sector mission, the Bank prepared revised estimates of gas demand for this study, assuming a 3-4% growth in GDP over the period 1995 - 2010, and assuming access to supply for about 60-70% of the industrial consumers in each region according to the proposed route of the Bolivian pipeline. The demand estimates were made considering economic benefit of the replacement of competing fuels by natural gas based on their economic costs. The final penetration rates were estimated for the various industries according to replacement factors for each product substituted, which take account of the practicality of substitution in various end uses. These forecasts for the South-South East showed an economic gas demand of 34 MMCMD in 2000, increasing to 47 MMCMD by 2005, which included 1000 MW of combined cycle power generation for 2000 - 2005. This corresponds to a total cumulated economic demand of 366 BCM over the period 1995-2015, with domestic sources able to supply only 145.5 BCM (51.9

BCM from existing reserves and 93.6 BCM from new discoveries). The pattern of fuels substitution indicated that displacement of fuel oil is the most important, representing about 48% of the total. Displacement of wood represents a high economic value for gas, and would come in second position as fuel displaced at about 17% of the total, in particular in the States of Parana, Santa Catarina, and Mato Grosso Do Sul.

2.44 More recent gas demand validation studies were carried out by SPG/Technoplan, and also by PETROBRAS' private sector partners in the Bolivian pipeline project. These studies have benefited from a detailed program of visits and estimation of conversion costs for specific large industries (particularly in Sao Paulo), the costs of industrial network expansions, and the current economic costs of gas and competing fuels. When based on import price parity of competing fuels, it is concluded with a high degree of confidence that the realizable economic demand for gas by the industrial sector in South-South East Brazil will reach *at least* 20 MMCMD by 2000. This does not include an upside potential generated by vigorous industrial growth, nor for gas used as feedstock, nor for gas used in power generation. This suggests that gas consumption will be supply constrained since the total gas available for sale from already producing domestic fields and Bolivian imports will be 8-9 MMCMD in 1996, rising to 20 MMCMD in 2000 and 24 MMCMD in 2005. Supply constraints could become acute if large gas fired power projects are implemented and domestic production in the South-South East is not increased. The current negotiations between the States and PETROBRAS are based on a quota allocation of Bolivian gas between the states, and do not represent economic demand forecasts.

2.45 With respect to power generation, recent studies carried out by ELETROBRAS in co-operation with the World Bank have confirmed the economic viability if large increments of new gas fired power generation capacity in the South-South East of Brazil. The preliminary results indicate that the inclusion of gas fired thermal generation of several thousand MW by 2015 would be justified in economic terms for gas prices compatible with Bolivian supplies and costs for hydro plants at 30% below current ELETROBRAS estimates. Moreover, due to delays in the implementation of the current expansion plans, thermal generation is the only option which could be implemented to avoid higher than normal risk of deficit. As an initial step, ELETROBRAS has included in the 906 MW of new combined cycle capacity in Sao Paulo/Rio de Janeiro in 1998/9, a further 906 MW in Sao Paulo/Rio de Janeiro in 2004/5 and an additional 418 MW spread over various locations in the S-SE by 2005. This suggests a demand for gas of about 4 MMCMD in power generation assuming base load combined cycle operation.

2.46 The pattern of gas utilization in Brazil is shown in Annex 2.4 (Fig.1). This shows that, of the 8.6 MMCMD available for sale in 1995, 66% was consumed by industry, 15% as fertilizer feedstock, 8% as petrochemical feedstock and 5% for residential use. There are large differences in the various forecasts with respect to the future pattern of economic demand, reflecting the fact that actual gas penetration in individual sectors will depend on the pricing policy adopted for competing fuels. This applies to the future cogeneration market, which will be mainly controlled by electricity price, and to the

development of CNG as vehicle fuel which will be linked to the price of diesel oil and to some extent gasoline and alcohol.

2.47 The PETROBRAS forecasts indicate that about 70% of gas supplied to the industrial sector will displace fuel oil, with the remainder displacing higher cost fuels including LPG and wood. They also indicate that the chemicals sector would represent the largest consumer with about 20% of total industrial consumption, particularly in Sao Paulo and Rio de Janeiro. The ceramics industry, which is largely located in Santa Catarina and represents one of the highest value uses for gas, would consume a further 12%. The food and beverage industry is dispersed in all regions and involves small and medium size plants, and would represent about 11% of total industrial gas consumption.

D. Conclusions

(i) When based on import price parity of competing fuels, the realizable economic demand for gas by the industrial sector in South-South East Brazil (within the service areas of the pipeline) will reach *at least* 20 MMCMD by 2000. Additional gas demand generated by vigorous industrial growth, feedstock requirements and power generation suggests that gas consumption will be supply constrained since the total gas available for sale from domestic sources and Bolivian imports will be 20 MMCMD in 2000 and rising to 24 MMCMD in 2005. This indicates the need to proactively promote domestic exploration activity and to consider additional gas import contracts for the medium to long term.

(ii) The benchmark level for the economic cost of domestic gas production is estimated at US$1.34/MMBTU in 1995 and increasing to US$1.61/MMBTU in 2000, which includes a depletion allowance of 0.34 to 0.61 US$/MMBTU. The total average cost of gas from domestic production and Bolivian imports is US$1.85/MMBTU, increasing from US$1.37/MMBTU in 1995 to US$1.98 /MMBTU in 2010.

3. THE PRICING OF GAS AND COMPETING FUELS

A. Introduction

3.1 Energy prices in Brazil are subject to a tightly-controlled system of regulation. Prices are proposed by the main federal agency, DNC (*Departamento Nacional de Combustiveis*), which is part of MME (*Ministerio de Minas e Energia*), and approved by the former DAP in light of Government anti inflationary policy and other macro economic considerations. The Constitution is still not clear on the subject of final responsibility of energy price setting, with two conflicting laws. Law 1178 of March 1991, gives responsibility to the Ministry of Finance, and the decree 507 of April 1992 gives responsibility to DNC.

3.2 The pricing policy shows distortions in the form of direct and cross subsidies. Since 1993, a determined effort has been made by the Government to increase consumer prices of fuel oil, LPG, electricity, and natural gas. During 1993, the price of HSFO was increased from US$2.40/MMBTU to US$3.16/MMBTU and has since remained at about this level through to 1996. There were similar increases in the price of LSFO, which is currently about US$3.9/MMBTU. Since 1993, the price of LPG delivered to residential consumers has increased from US$6.0/MMBTU to the current level of about US$10/MMBTU, with low income households with a low electricity consumption threshold receiving a direct subsidy on LPG. The Price of LPG supplied in bulk is about US$7/MMBTU. For electricity, the average price to the consumer has increased substantially since 1993 and is currently about US$60/MWh. Current prices for natural gas and competing fuels are shown in Annex 3.1.

B. Natural Gas Pricing

The Existing Pricing Structure

3.3 The current structure of natural gas pricing is often simplistic and does not correspond to an efficient model. Bulk supply prices from PETROBRAS to the distribution companies have been fixed by DNC according to Portaria with frequent revisions. Through 1994 to 1996, these prices have remained at about their current levels of US$2.5/MMBTU for COMGAS and GEG, and US$1.5/MMBTU for petrochemical use. Until now, the gas supply contracts from PETROBRAS to the distribution companies did not specify certain requirements which are normal in gas supply contracts, including base price, indexation formulae and price revision clauses. Although the contracts stipulate take or pay conditions for the distribution company, PETROBRAS is not subject to penalties for failure to supply, but has only the obligation to make up the shortfall through the delivery of an equivalent quantity of petroleum products. This is not an incentive to promote gas market. The DNC's control of the prices of the major competing fuels indirectly imposes a cap on natural gas prices.

3.4 The approval of retail prices to consumers has been the responsibility of each State, but since the commencement of the Plano Real in 1994, the retail prices have been approved at the Federal level. Historically, CEG and COMGAS have established gas distribution tariffs using classical block tariff formulae. During 1994, COMGAS moved to a system of two-part tariffs, including a fixed and a variable component.

General Principles of Gas Pricing

3.5 The principles for setting tariffs must take account of the structure of the gas sector, particularly the degree of vertical integration and the possibility to introduce competition into the different segments of the industry. Experience indicates that it is beneficial to have clear interfaces between the three basic functions of (i) exploration and production, (ii) gas transportation and (iii) gas distribution. As a consequence, tariffs or contractual arrangements need to be defined at each commercial interface, as well as gas sale to end consumers. The scheme is illustrated in Annex 3.2 (Fig.1) which defines the border price of imported gas and production cost of domestic gas, a transport tariff, bulk supply tariffs to the local distribution companies (LDC's) and large volume industrial users, and retail tariffs from LDC's to final consumers. Prices at each interface are built up to cover the costs of each activity, and the price to end users may be set at a level which reflects the cost of supply (cost plus approach), or at a higher level that reflects the value in use of the gas (market based approach). With such a system, regulation is made necessary by two basic requirements, (i) the need to maintain and encourage competition, and (ii) the need to regulate prices for natural monopolies where no competition is feasible such as gas transport.

3.6 The *cost of service* approach sets the average tariff to cover all the costs of the gas industry, by the addition of the gas price (at the wellhead and import point) plus the cost of transport, storage, and distribution. This approach is most appropriate for countries with a permanent excess supply of gas that cannot be exported, and gas prices can be set according to the Long Run Marginal Cost of supply, and possibly with a depletion fee added to reflect the opportunity cost of using the resource today rather than saving it for the future.

3.7 The *market price* approach reflects the different commercial values of gas to different consumers according to the value of the fuels replaced by natural gas. Here the price of gas to each consumer group is linked to the price of competing fuels by equalizing the benefit to the consumer of using gas or the competing fuels. This must take into account the cost of switching existing consumers to natural gas as well as the relative thermal efficiencies of the gas and non-gas appliances, and results is a parameter known as the *netback value* of gas, which represents the true market value of gas to the consumer. The gap between the total cost of service and the market value can lead to a surplus. The sharing of the surplus along the gas supply chain and how it is taxed by Government needs to be consistent with the Government's objectives concerning the need to attract investments for upstream exploration and development, and the construction of new gas transmission and distribution systems. This is a key issue for

Brazil. The market price system is most appropriate in countries where natural gas imports are needed to meet the demand, such as Brazil, because it encourages the most economically efficient use of natural gas and competing fuels. This approach is more suited to markets in their developmental phase in order to fully exploit the competitivity of gas against alternative fuels.

3.8 It is important to distinguish between the concepts of homogeneous and differential pricing. Homogeneous pricing requires a single price to all consumers irrespective of which fuels are in competition with gas. Differential pricing requires different prices charged to consumers on the basis of the price of the fuel replaced, and has several advantages. Firstly, a single price which would be too low could lead to the development of non economic uses of gas. Secondly, a gas price charged for a particular application below its break-even price may reduce the incentive to make energy savings and lead to wasteful use of gas. This conservation aspect is particularly important when the gas resource is in limited supply. Thirdly, a differential pricing system is more flexible to ensure an appropriate sharing of economic rent between the consumers and the gas seller. For each gas application the seller is able to adjust the price (slightly below break-even to maintain an incentive for using gas) in order to maximize its share of the economic rent. This is particularly important for the mobilization of financial resources required for development phase of the gas industry. The arguments in favor of a differential pricing system are particularly strong in the case of Brazil, where a prerequisite to the success of the gas development program is the substitution of fuel oil in the industrial sector.

Pricing of Gas Imports

3.9 Although this report does not deal specifically with the gas supply agreement with Bolivia, there are some general provisions which would give to the contract the required flexibility to the benefit of both sides. Make up and carry forward provisions are essential for providing flexibility concerning the volumes of gas delivered, and allow the buyer's take or pay obligations to be averaged out over the life of the contract. The take or pay amount may be defined as a basic percentage (70% to 100%) of Annual Contract Quantity *less* under deliveries by sellers *less* quantities of gas the Buyer was unable to accept for reasons of Force Majeure *less* accumulated Carry-Forward. If the buyer takes less than the contract amount in any year, the difference is carried forward in a Make up Bank, allowing the buyer in later years to take gas free of charge up to the amount in the Make Up Bank.

3.10 Information in the public domain suggests the price escalation formula in the agreement with Bolivia is designed to allow the price of gas to automatically reflect changes in energy markets, and that the indicators selected are the international prices of a basket of fuel oils which are: HSFO (Italy), LSFO (US Gulf), and LSFO (NW Europe).

3.11 In gas supply contracts, the seller may wish to include a general inflation term as a protection from falling oil prices. There is also the possibility to introduce "top stop" or "bottom stop" formulae. For example , in a "bottom stop" formulation, the price of gas would be the greater of P1g and P2g, with:

$$P2g = Po \times PI / PIo \qquad \text{with } PI = \text{general inflation index}$$

3.12 This formulation (simplified) would protect from a sharp increase in fuel oil prices. A combination of "top-stop" and "bottom-stop" formulas may also be used to provide a more sophisticated protection against large price variations.

Pricing of Domestic Gas

3.13. **Pricing of Domestic Gas Production:** Domestic gas will eventually have to compete in the same market as Bolivian gas. The Constitutional Amendment No.9 has removed the constitutional barriers to independent companies exploring for and producing gas in Brazil. If the dominance of PETROBRAS in domestic gas production can be reduced by a proactive campaign to make available good prospective acreages to international competition, and open access for gas transportation is implemented for producers and importers, then this will create the conditions for gas to gas competition, and the producer price of gas can be left to find its own level in a competitive market. A share of the economic rent generated (excess profit for the producer) can be captured by Government through tax.

3.14 The delivered cost of domestic gas is lower than the cost of Bolivian gas since the transportation distances from the source to the market are much lower. The economic cost of domestic gas production is difficult to estimate, but an indicative production cost in 1995 is estimated at US$1.34/MMBTU, which includes a depletion allowance of US$0.34/MMBTU. Therefore, there is a greater margin for the delivered price of domestic gas to be competitive in the lower value markets than Bolivian gas. However, the same fundamental pricing principle applies equally to domestic gas and Bolivian gas, which is that the price of gas at the various commercial interfaces should reflect the value of gas in the market, and that if the cost of production plus transportation of domestic gas exceeds the netback value, then the supply option is uneconomic.

Gas Transportation Tariffs

3.15 The Bolivian gas pipeline project has the characteristics of a natural monopoly for gas transport and therefore transportation tariffs, which are linked to fixed investments in infrastructure, should be subject to price regulation. However, the purchase of cost of Bolivian gas is linked to the international price of fuel oil, and the sale of gas, while not completely subject to free interfuel competition today, does not necessarily require such price regulation in the future. For this reason the gas transport and gas commodity elements should be separated. This principle has major advantages, particularly for large customers with the option to switch to alternative fuels who need to know what they pay

at the margin for gas and for transport separately, in order to make correct fuels purchase decisions which would benefit themselves and promote the efficient operation of the whole gas supply system. Separation of the two components makes recalculation of the final consumer tariffs easier, secures a better transparency in terms of identification of exact origin of price changes, and leads to improved economic efficiency.

3.16 The pipeline transport tariff should comprise a formula with two components, a capacity and a variable charge as represented in Annex 3.2 (Fig.2). The *capacity charge* covers the fixed costs involved in pipeline investment and operation, and reflects long run marginal cost (LRMC). It includes depreciation, return on capital (net fixed assets), income and social taxes, and part of the operating costs. The fixed costs need to be divided by the total capacity of the system to obtain the capacity charge component of the tariff, expressed in US$/MMBTU of capacity. The *variable charge* is linked to the volume of gas actually purchased, and reflects short run marginal cost (SRMC). This includes fuel consumption of compressors, system losses and part of the operating costs. The variable costs are divided by the actual throughput of gas to give the variable charge or volume unit charge component of the transport tariff, expressed in US$/MMBTU of annual throughput.

3.17 Transmission investment is a function of peak utilization, and a major problem is the management of peak utilization of various consumer classes. Therefore the transport tariffs should reflect the principles of peak load pricing, where peak consumers bear all the capacity costs, with off-peak consumers exempted. This means that fixed capacity costs will be allocated among peak consumers (or classes of consumers) according to their proportional use of the system at the peak period. The measure of this proportion of peak utilization may be based on the gas supply contractual "nominations" given by consumers. Even if the consumer does not use the transport service exactly according to its nomination, the right to this nomination remains, and forecloses use of the system for other customers. The interruptible consumers on the other hand, should only be charged with the variable unit charge. However, in order to maintain the incentive of the transport company to provide an interruptible service, it is advisable to include a contribution to fixed costs in the interruptible tariff, (incentive payment or additional volumetric charge). It is thus important that these rights be correctly priced in order to avoid under utilization of the system.

3.18 Transportation distance and therefore geographic location is a major component of transport cost. The GOB has agreed to provide gas to all the states along the Bolivia pipeline at a uniform city gate price. Of the 16 MMCMD supply from Bolivia, 3.6 MMCMD is allocated for markets south of Curitiba, in Santa Catarina and Rio Grande do Sul. Projections suggest that the markets off the main trunkline in Sao Paulo and to Curitiba could absorb all the Bolivian gas if large scale gas-fired power generation are constructed in Sao Paulo, and this would result in an the average transportation cost of about US$1.2/MMBTU. Inclusion of the southern branch line to Porto Alegre results in a further increase to about US$1.6/MMBTU. Although the inclusion of the southern branch lines increases the average transportation cost, its inclusion will lead to a reduced

risk of low market take-up in the early years of the project unless large new increments of gas fired power generation are confirmed in Sao Paulo in the near future.

3.19. If all the Bolivian gas can be absorbed along the main trunkline, there is economic justification for the southern states to bear the full *average* cost of transport in the main trunk line plus the full *incremental* cost of the branch line to Porto Alegre (akin to distanced-based tariffs). This approach leads to an average economic cost for Bolivian gas (ex transmission) of about US$2.3/MMBTU along the main trunk line as far as Curitiba (US$1.0/MMBTU commodity plus US$1.3/MMBTU transport), which co-incidentally is close to the price of domestic gas currently sold by PETROBRAS to COMGAS. When the cost of industrial distribution networks is added on, the final cost of gas to the consumer should be competitive against alternative fuels in key markets such as Sao Paulo, where fuel oil predominates and current prices are US$3.1/MMBTU (1A-HSFO), US$2.9/MMBTU (3A-HSFO), and US$3.8/MMBTU (1B-LSFO). These prices reflect import parity values and are marginally higher than the international prices. If priced at export parity, the economic price of HSFO would be about US$2.2/MMBTU which would make gas uncompetitive although it is noted that the environmental costs of HSFO are not internalized in the current fuel oil price structure.

3.20 However, the true economic cost of Bolivian gas to the states south of Curitiba would need to bear an additional average transport cost of about US$1.1/MMBTU to cover the marginal cost of the southern leg, resulting in an average ex-transmission economic cost of gas of US$3.4/MMBTU (US$1/MMBTU commodity and US$2.4/MMBTU for transport). When gas distribution costs are added on and gas displaces high cost alternative fuels for the ceramics industries located in the southern states, the economic cost of gas supply is likely to be competitive with the netback value of gas in end use. However, the displacement of fuel oils by gas would be difficult.

3.21 The process of geographical disequalization of petroleum fuels has already started, and the eventual goal should be to have gas transport tariffs bear a relation to transport distance to avoid uneconomic fuels purchase decisions. In practical terms and with the arrival of Bolivian gas, Brazil will begin to benefit from a limited number of geographically disperse sources of gas which would tend towards low disparity among transport tariffs even with a distance based system. The eventual acquisition of other sources of gas, such as from Argentina through a southern pipeline or LNG, would make the implementation of a full distance-based tariff system quite easy. However, in the developmental phase, an initial step could be a system based on a degree of disequalization of transport tariffs based on the concept of trunk line and branches, with a single regional transport tariffs for the main trunk line to Sao Paulo (or Curitiba), and a single regional transport tariffs for each of the southern and northern branch systems. Systems of distance-based tariffs are in operation in many progressive gas industries worldwide, and the key requirement is to have the transparent separation of the gas price into the components of gas commodity and gas transport.

3.22 The delivered cost of domestic gas is lower than the cost of Bolivian gas since the transportation distances from the source to the market are much lower. The economic cost of future domestic gas production is difficult to estimate, but an indicative production cost in 1995 is about US$1.34/MMBTU, which includes a depletion allowance of US$0.34/MMBTU. Therefore, there is a greater margin for the delivered price of domestic gas to be competitive in the lower value markets than Bolivian gas. However, the same fundamental pricing principle applies equally to domestic gas and Bolivian gas, which is that the price of gas at the commercial interfaces should reflect (or be netted back from) the value of gas in the market, and that if the cost of production plus transportation of domestic gas exceeds the economic netback value, then the supply option is uneconomic.

Pricing of Gas to LDC's and Industrial Consumers

3.23 As noted above, the gas transport and gas commodity elements should be separate and transparent although LDC's and large industrial consumers would pay a combined ex-transmission price for delivered gas. This allows large customers with the option to switch to alternative fuels to make correct fuels purchase decisions to the benefit themselves and the efficient operation of the whole gas supply system. Separation of the two components makes for better transparency in terms of identification of exact origin of price changes and makes recalculation of tariffs easier. It is recommended that the full costs of gas commodity, which are effectively set by the terms of the Bolivian contract, are passed on to the LDC's and large industrial consumers. This permits accurate price signals of on the cost of gas to flow through to these consumers and allows the transport company to act solely as a transported. The gas purchase contracts should contain all the provisions for sharing the constraints between seller and buyer, including contract duration, gas volumes, take or pay clauses, base price and indexation formulae, and price revision clauses.

3.24 In the industrial sector, gas is in competition with a variety of fuels. In heavy industry, fuel oil is the main competitor, LPG and diesel oil in light and medium industry, and electricity for specific uses. The value of gas may be defined as the maximum price the industrial consumer is willing to pay, taking into account the benefits of efficiency, capital and operating costs, and environmental advantages of natural gas. This is represented by the concept of break-even price or netback value. In order to encourage vigorous and economically efficient expansion of natural gas distribution and utilization activities, for the industrial consumers it is appropriate to allow the seller and buyer to negotiate freely on gas price taking account of the pattern of alternative fuels usage. Here, a formula could be used containing a capacity charge and a variable charge. The capacity charge would cover the whole infrastructure required to deliver gas to the consumer, including the transmission system and regional transmission lines, pressure reducing and metering stations and distribution systems as appropriate according to the principles of peak load pricing. The variable charge would reflect the variable operating costs and the gas commodity charge, and the commodity charge could be pegged to competing fuels through simple indexation.

3.25 This system would reflect the different commercial values of gas to different users according to the value of competitive fuels to be replaced, and would ensure both maximum economic benefit is derived from the gas resource and sub-optimal gas application is discouraged. Germany has adopted this system where it works well and gas selling companies subscribe to contracts which include price indexation formulas reflecting the type and price of competing fuels, with the objective of securing the permanence of gas sale. However, a permanent tracking of the gas value in all markets in line with price fluctuations of competing fuels is required. In the industrial sector, reference can be made to the main competitors of gas, such as fuel oil and diesel oil, so that prices of these products could be used as main variables in indexation formulas. Market value tariffication allows maximum benefit to be captured by the gas selling company, but present the following drawbacks:

(i) Necessity of a permanent adjustment to fluctuations of competing fuel prices and to technological developments able to modify the terms of the competition.
(ii) Inequality among consumers in that some consumers located in the same area and consuming the same volume may be charged different prices.
(iii) Complexity and high cost of administration, because the price adaptation to each case requires a major commercial effort, particularly in the case of dispersed markets.

Pricing of Gas from LDC's to Residential and Commercial Consumers

3.26 Three main types of tariff structure are generally considered for residential and commercial consumers:

(i) Tariffs with minimum payment, where the customer pays a unit price for each energy unit consumed, but is obliged to pay a minimum agreed amount for a given period of time.

(ii) Block tariffs, where the customer pays for the first energy units consumed during the period at a given price, the following units at a different price (generally lower), and so on for successive "blocks" of consumption.

(iii) Binomial tariffs, where the billing involves a fixed charge destined to recover the fixed costs associated with the customer's use of the distribution system, and a variable charge proportional to the volume consumed during the period.

3.27 The binomial formula presents major advantages. On the cost side, the fixed charge component aims at reflecting the real costs generated by a customer by the simple fact of its existence. These include such factors as the capital cost of a meter, and those associated with meter reading and billing. On the revenue side, the distribution company is secured a revenue independent of consumption. For each class of consumer, the number of binomial tariffs must be determined.

3.28 In the *Residential Sector*, the typical uses are for cooking and water heating, where gas competes mainly with LPG and electricity, and these two fuels may compete indistinctly and in combination with gas. Since neither of these fuels competes solely with gas for a specific use, a single binomial tariff for the residential market is recommended. LPG is sold on the basis of a unit cost, and the electricity tariff does not include a fixed charge but only discount levels as a function of consumption (block tariff). Within the context of real energy prices (following economic costs), electricity cost is far higher than LPG. This means that the competitive reference in binomial formula will be LPG rather than electricity, since using electricity as a reference would lead to loss of gas displacement by LPG.

3.29 In the *Commercial Sector*, gas competes with LPG and to a lesser extent electricity for cooking. For furnaces, the main competitor is electricity, followed by LPG. For water heating, the main competitor is electricity, and to a lesser extent LPG. For boilers, diesel oil is preferentially used followed by LPG. For this situation, three types of binomes are appropriate. A first set of two commercial binomes for competing with cooking and water heating use (C1) and (C2) referenced on the price of LPG, and a third binome for large commercial customers using boilers(C3) where diesel oil is the competitor and therefore referenced on diesel oil.

3.30 The methodology of determining a gas tariffs at retail level and the principles of long term planning are illustrated in Annex 3.2 (Figs. 3 and 4). An overview of gas price systems in six European countries is presented in Annex 3.3, including an explanation of tariffication parameters and a detailed analysis of pricing formulas. It appears that various solutions have been adopted to deal with both Government rules and competitiveness requirements. Despite the unavoidable reference to the two basic approaches explained above, the examples of European countries show that there is no real common structure, and very different formulas have been chosen from one country to another.

Pricing of Gas to Power Generation

3.31 The price of gas has to reflect its true economic value onto the power generation system, considering future long term development of the system and the implications on the Long Run Marginal Cost (LRMC) of electricity produced. ELETROBRAS' latest planning exercise and the Plano Decenal for 1996-2005, estimates the LRMC of power generation for the SSE-Central West System as US$39/MWh when calculated using an economic discount rate of 10% (It is noted that the LRMC increases to US$60/MWh using a discount rate of 15%). The economic viability of burning gas in combined cycle plants can be gauged by calculating the maximum price of gas to the power plant to produce electricity in line with the LRMC. For a combined cycle plant operating at base load, the price of gas to the power plant is estimated around US$3-3.5/MMBTU for a generation cost of US$39/MWh. This indicates that combined cycle plants could be economically competitive in line with the LRMC, since the cost of Bolivian Gas is

expected less than this ex transmission. It is noted that the economic viability of gas fired plants could be further enhanced, since they can be located close to the center of demand and thereby offset the cost of transmission, which for the S-SE is estimated at around US$10/MWh.

3.32 However, this result can only be used for broad screening purposes, and the rigorous economic evaluation of gas use in combined cycle plants, operating in *complementarity mode* to hydro power (with the gas-fired plant playing a role analogous to a reservoir) requires specific study using a system simulation model of hydro and thermal generation. ELETROBRAS, in co-operation with the World Bank, is preparing a detailed evaluation of the viability of using gas in thermal plants. The study is based on the definition of the least cost expansion plan and the planning models being used are those currently used by ELETROBRAS for defining the Planos: a long term linear programming optimization model, DESELP, and a more detailed medium term simulation model, the MODDHT module of the OLADE/BID expansion planning model. The economic feasibility of gas fueled thermal generation in the system will be tested through solutions provided for these models, and the solutions will be tested under several assumptions for robustness. The least cost simulations will take account of the proposed electrical transmission interconnection between the N/NE and the S/SE/MW systems.

3.33 The preliminary results of this work suggest that inclusion of gas fired thermal generation in the System up to about 5,000 MW up to the year 2015 appears justified in economic terms for gas prices of US$2.7/MMBTU, discount rates of 10-15%, and costs for hydro plants at 30% below current ELETROBRAS estimates. This assumes an unconstrained gas supply. Moreover, due to delays in the implementation of the current expansion plans, thermal generation is the only option which could be implemented to avoid higher than normal risk of deficit. As an initial step, ELETROBRAS has included in the 906 MW of new combined cycle capacity in Sao Paulo/Rio de Janeiro in 1998/9, a further 906 MW in Sao Paulo/Rio de Janeiro in 2004/5 and an additional 418 MW spread over various locations in the S-SE by 2005. These results assume that the generator would be obliged to take volumes of gas from the pipeline company equivalent to base load operation, although under favorable hydrological conditions the thermal power plants could be required to operate far from base load to avoid the spillage of water. However, there is always the possibility that under favorable hydrological conditions, the thermal power plants would be required to operate under reduced load to avoid the spillage of water. In this case, the power producer may seek an alternative market for natural gas to ensure all contracted gas can be sold under all circumstances to avoid spillage of water. Implementation the power projects included in the new Plano Decenal would be equivalent to a gas demand for power generation of up to about 4 MMCMD. Contracts for gas supply from the transmission system to power plants and the secondary market will to reflect the commodity and capacity charges to take account of the impact of the reserved capacity of the transmission pipeline.

3.34 If the development of thermal generation capacity is regarded as economically desirable in the South- South East, gas may be in competition with fuel oil, particularly if

produced in excess by PETROBRAS refineries. For conventional Fuel Oil fired power stations running at base load, the netback value of fuel oil plant with flue gas desulfurization is around US$2.0/MMBTU when measured against an LRMC of 39US$/MWh. This indicates that the value of fuel oil for power generation is very low at this level of LRMC, but could absorb volumes of high sulfur fuel oil when priced in line with export parity.

Taxation and Distribution of Economic Rent

3.35 Economic rent in is defined as the return in excess of the minimum necessary to cover all the costs incurred in a given activity including an appropriate remuneration of capital. It is essentially of permanent nature and is distinguished from temporary excess profits generated from competitive innovation processes. Economic rents arise in certain monopolistic situations, and are common in the major natural gas related activities of production, transmission and distribution. Rents may also be created by gas pricing policy, for example if gas price is set at a higher level to limit the demand in line with a supply shortage situation (price rationing rent).

3.36 Economic rents, when they exist, can be shared between the various participants of the system which are the Enterprise, the Consumers, and the Government. For each participant, it is possible to allow either the realization of the rents through excess profit or suppress them through regulation. In the case of an Enterprise (production, transport or distribution) the economic rent may be left which would allow the Enterprise to earn excess profit or invest in infrastructure. In the case of consumers, the economic rent may allow them to benefit from lower prices, and for the Government economic rents at all stages of the gas chain may be captured through tax.

3.37 Considering the future development of gas sector in Brazil, particularly during the initial phase, the existence of economic rents is limited by the constraints three principal points represented by the cost of gas supply imposed by the Bolivian, the cost of domestic production in Brazil, and consumer prices which are dominated to an extent by competition with low price fuel oil.

3.38 If at the production level the price of domestic gas is set to reflect the value of gas in the market (less transmission and distribution costs), then the price will be higher than real full cost of production which would generate an economic rent. In this case the government should ensure a direct appropriation of this production rent at the exploration and production stage. However, in view of the current efforts by the government to open up the upstream to international competition, it will be particularly important to appropriate the maximum rent possible without affecting the incentives to explore, develop and produce gas. A wide range of options are available for this purpose, including (i) creation of joint ventures between companies and the State, allowing risk sharing without appropriation of the whole rent by the Government; (ii) appropriation of rent by taxation on gas revenues; and (iii) appropriation of rent by taxation on gas profits more in line with the basic nature of the rent to capture.

3.39 At the transmission level, the potential rent accruing from a natural monopoly may be controlled through regulation using a mechanism of "rate of return" control. This has the advantage of ensuring the appropriate financial viability of the activity, but obviously limits the incentive to reduce costs and may lead to non economically justified investments in order to expand assets and generate extra profits. In addition, there is less incentive for the pipeline company to keep the pipeline running full than with regulation through a "price cap "mechanism

3.40 At the distribution level, the companies face critical issues to ensure gas penetration on the basis of "take or pay" contracts in a market dominated by low price fuels. Both COMGAS and CEG have a tradition of manufactured gas production and marketing, and each are facing marketing and financial difficulties over a transition period of several years. They have to manage with the operational and cost burden of Town Gas plants, and to take on heavy investments in network conversion and extension. They are pulled between two opposing trends, which are either to increase gas selling price in order to improve their financial situation, or decrease gas selling price to capture additional consumers.

3.41 After the prices of competing fuels have been rationalized as described above, and cross subsidies have been removed, gas selling prices to captive consumers will have to be regulated, in order to simulate competitive pressures. This may be achieved through a "cost of service" regulation based on a minimum rate of return, or by "price caps" imposed on selling prices. These price caps could include a reference to the price of competing fuel, a built in adjustment for progressive efficiency improvement, and a "cost pass through " allowance to reflect changes in gas input price.

3.42 Improvements in the establishment of transaction prices between producer and distribution companies would include several measures:

(i) Ensure the gas pricing framework is based on the system of market based pricing.

(ii) For domestic gas, the existing production price and transport price should be separated. PETROBRAS to develop separate business areas for gas production and transport with separate accounting;

(iii) If exploration and production can be proactively opened up to private sector and open access for gas importers and domestic producers is implemented, producer prices need not be regulated. Until this happens, the maximum producer price of domestic gas netted back from its value in the market, with a share of the economic rent at the producer level captured by GOB through tax.

(iv) For bulk gas supply to distribution companies and very large consumers, separate the gas purchase price and transport price in supply contracts. The transport tariff should be based on a capacity charge proportional to participation in peak utilization of transport infrastructure, and a variable charge related to the volume of gas sold. The main component of the variable charge is the cost of the gas (the commodity) for which the price should take account of the fuels displaced in the market.

(v) Establish gas purchase contracts between gas producer, gas transport company and distribution companies or very large industrial consumers, which contain all the provisions for sharing the constraints between seller and buyer, including contract duration, gas volumes, take or pay clauses, price indexation formulae and revision clauses.

(vi) Consider basing gas transport tariffs on the concept of trunk line and branches, with a single regional transport tariffs for the main trunk line, and an additional single regional transport tariff for each of the southern and northern branch systems.

(vii) Establish retail prices based on binomial formulae for residential, commercial and industrial customers of distribution companies, including a demand charge (covering fixed transport and distribution costs), and a volumetric charge covering unit gas cost and the variable part of transport and distribution.

D. Petroleum Products and Refinery Pricing

The Structure of Petroleum Products Prices

3.43 **Current Structure of Prices:** The prices of petroleum products in Brazil are fixed by decree from the Ministry of Finance on the basis of specific legislation, and taking account of proposals made by the DNC, the DAP and the *Secretaria do Desenvolvimento Regional* (SDC). A breakdown of the current petroleum products pricing structure and estimates of the economic costs of these fuels in the state of Sao Paulo are presented in Annex 3.4, Tables 1 and 2 respectively. The general framework of petroleum product prices is shown in Table 3.1:

Table 3.1 Framework of Petroleum Product Prices

Simplified Structure	Management of Subsidies
Crude Oil Cost - Domestic Crude Oil Subsidy - Import Refining Cost Cross Subsidy	Conta Petroleo Automatically Balanced
= Realization Price - PRi[1]	
+ Transport Equalization Funds[2]	Conta Derivados,FUP& Conta Alcool(FUPA)
= Price Billed by Refinery at Sec. Distribut'n Bases	
+ Distribution Margin	
= Price Billed by Distributor + Sales Margin	
= Consumer Price (Exc.Taxes)	

1 "Precio de Realizacion" for each product, and "Precio Medio de Realizacion" for the whole expenses
2 "Frete de Uniformizaçao de Preços"

3.44 This pricing structure also incorporates financing costs and various taxes, both at refining and at distribution level, including: Finsocial, PIS, and PASEP as social contributions; ICMS as a State tax; IVVC as a Municipal tax applied only at consumer price level. This general framework incorporates four levels of subsidies:

(i) A major subsidy at the level of crude oil cost, as the difference between cost of imported and domestic crude oil.
(ii) A cross subsidy allocated to each product destined to lower the price of "sensitive" products: LPG, fuel oil, naphtha.
(iii) An equalization component (FUP) for partial geographical uniformization of consumer prices over the country.
(iv) A fixed formula which links the prices of gasoline an alcohol (hydrated) in secondary distribution bases and leads to subsidize alcohol prices.

3.45 **The Realization Price (PRi).** The levels of petroleum product prices within this structure, and a comparison with their economic costs of supply are shown in Table 3.2. It may be seen that the PRi corresponds to the gross price of each product at refinery gate, excluding all contributions and taxes. The concept behind the PRi is that the refinery must, through the sale of products destined for the domestic market, generate an average receipt able to cover the average cost of production and processing of a barrel of crude oil, including a capital recovery component necessary to secure the profitability of refining activity.

Table 3.2 Petroleum Products Fuels Prices and Economic Costs-February 1996 (US$/bbl)

	Average Product	Gasoline	Diesel	LPG	F.O.1A	F.O.1B	Jet Fuel	P'Chem Naphtha
Production Structure (%)		19.4	37.7	4.8	11.5	0.2	17.7	8.7
Ex Refinery Cost(VMS)	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2
Cross Subsidy		12.3	1.3	-11.4	-3.7	-0.8	3.3	-5.4
Ex Refinery Price(Pi)	*18.2*	*30.6*	*19.6*	*7*	*14.5*	*17.6*	*21.6*	*12.8*
Ex Refinery Price(Incl.Tax)	30.1	58.3	31.2	14.3	21.1	25.1	34.1	17.7
Price Billed by Refinery(Incl. FUP)*	34.7	65.7	40.6	14.3	21.1	25.1	33.7	17.7
Ex. Retail Distribution Price	38.7	70.5	43.6	28	22.9	26.9	37.3	17.7
Consumer Price(Incl.Tax)	45.3	83.2	54.7	31.6	23	26.9	37.4	17.7
International Price (cif Santos)		*18.5***	*24.7*	*22.1*	*13.0***	*15.3***	-	*23.3*
International Price (Sao Paulo)***		31.6	38.5	34.6	28.4	28.4	13.7	36.5
Consumer Price(Excl Tax)	33.4	55.5	43.1	24.3	16.4	19.3	24.9	12.8

Source: PETROBRAS & World Bank Estimates.
* Billed by refinery at PETROBRAS secondary distribution bases
* *Export Parity - Otherwise Import Parity, *** At Consumer Gate.

3.46 The average receipt of refining or *Valor Medio de Realizaçao* (VMR), has to cover average crude oil and refining costs, broken down into four groups according to decree 1599/77, which are:

Group I	Cost of crude oil and other raw material
Group II	Cost of refinery manpower
Group III	Crude oils transport and other refining costs
Group IV	Capital costs including depreciation and remuneration

3.47 However the cost of crude oil calculated in Group I corresponds to domestic crude, which generally has a lower cost than imported crude. The difference between the cost adopted in Group I and the cost of imported oil is accounted for in a special fund, the "Conta Petroleo" destined to compensate PETROBRAS. The consequence of this system is that: (i) The general level of petroleum product prices is lowered by a subsidy equal to the difference between domestic and imported crude (ii) since the "Conta Petroleo" is never reimbursed, PETROBRAS accounts show a chronic deficit, corresponding to a debt to PETROBRAS by the Government, which hinders the capacity of PETROBRAS to invest in exploration, production and refining, and (iii) lack of transparency in PETROBRAS refining efficiency since this makes it difficult to compare its refining and oil production costs with international standards and the true cost of refined products with their international prices.

3.48 Furthermore the realization price of each product (PRi) is fixed so that the weighted average by respective volumes sold is equal to the (VMR), with each PRi including a cross subsidy, positive or negative. The level of subsidy on each product is given in Table 3.3. This is calculated as the difference between PRi and VMR multiplied by the volume of product over the year, and does not exactly reflect the real distortion against the value of petroleum products as expressed by international prices.

Table 3.3 Pattern of Cross Subsidy

Product	Subsidy
Gasoline	+70.3%
Diesel Oil	+25.7%
Paraffins & Kerosene	+4%
Naphtha	-11.9%
Fuel Oil	-32.6%
LPG	-38.5%
Jet Fuel & Residues	-13.4%

Source: World Bank Estimates 1993 Gas Sector Mission

3.49 **The Price Billed by Refinery and Geographical Equalization.** The price billed by refinery actually refers to the price at secondary distribution bases, and is obtained by adding to the realization price of each product (PRi), the various taxes, financing costs, and a component known as the *Frete de Uniformizacao de Precos* (FUP). The FUP covers the transportation costs of all petroleum products from the refineries to the secondary distribution bases. There is an FUP component included in the price of only some products (such as gasoline and diesel) but not in others (such as fuel oil and naphtha), and it is a mechanism for achieving the geographical equalization of product prices at the secondary distribution level through a cross subsidization of these costs among products. The policy of price equalization over the country has been applied as early as 1938 with the creation of the CNP (which later became DNP). From 1978, this policy was applied to gasoline, diesel oil, jet fuel, kerosene and LPG and was extended to alcohol fuels. However, since 1991, a policy of partial disequalization was launched involving freeing-up of prices fixed by distributors and the setting of maximum prices by city for consumers of gasoline, diesel and alcohol (with prices ex secondary distribution bases maintained uniform).

3.50 According to this system, each product price includes an equalization component designed to cover:

(i) The cost of products transfer between PETROBRAS refineries and terminals and cost of transport to primary distribution points, after equalization of prices billed to distribution companies (excluding taxes).

(ii) The cost of products transfer between primary and secondary distribution bases.

(iii) The differences between prices applied by PETROBRAS to imported products and real CIF costs of these products.

3.51 The compensation of these funds is administered through DNC, through indemnisation to PETROBRAS and distribution companies, using the funds generated by FUP components. These funds are registered into the "Conta Derivados", similar to the "Conta Petroleo". FUP components are applied to gasoline, diesel oil, lubes, and LPG, which means that automotive fuels are bearing the most part of the equalization process. In June 1993, FUP components amounted to US$6.5/bbl for gasoline, US$7.83/bbl for diesel oil, and US$2.74/bbl for LPG. Initially the objectives and justification of price equalization were socio economic objectives linked mainly to regional development and improved distribution of economic activity. The consequences of this cross subsidy process are:

(i) Consumers of automotive fuels close to supply sources pay for transport costs of consumers which are remote from these sources.

(ii) all automotive consumers pay for transport costs of products which do not include a FUP component.

(iii) All automotive consumers pay for difference in import cost of products which do not include a FUP component.

3.52 **The Price Billed by Distributor and Consumer Price.** The price billed by the distribution companies is obtained by adding the distribution margin, the ICMS tax, the various social contributions, and the financial costs to the ex refinery price. Distribution margins are in the range US$1.75/bbl (diesel oil) to US$2.62/bbl (jet fuel) and US$8.56/bbl for LPG. The consumer price includes the sales margin (about US$5/bbl for diesel oil and gasoline) and the IVVC tax, which is about 3%.

3.53 **Alcohol Fuel Prices.** Two types of alcohol fuels are used in Brazil. Firstly there is anhydrous alcohol, which is mixed with gasoline. PETROBRAS buys anhydrous alcohol from producers and sells it to distribution companies at gasoline price. Secondly there is hydrated alcohol which is used directly in engines, with a price adjusted to ensure competitivity with gasoline (75% of gasoline price since Jan. 1989). Following the partial disequalization program of November 1991, this ratio is applied to the price billed ex distribution bases and not to the consumer price. Hydrated alcohol is purchased by distribution companies either from producers or PETROBRAS, at the same price.

3.54 The structure of alcohol prices is shown in Annex 3.4, Table 3. With this system, prices of alcohol fuels are not connected to the real purchase price from producers. The differences are compensated by an equalization component called FUPA component in

the price structure (FUPA fund was created in December 1984 following the model of FUP). FUPA components are destined to cover:

(i) Transport costs of alcohol over the whole country to ensure a uniform price in secondary distribution bases.

(ii) Cost of formation and maintenance of alcohol stocks by PETROBRAS.

3.55 The FUPA component is positive for anhydrous alcohol because gasoline price is higher than the cost of buying alcohol, transporting and mixing it with gasoline. In contrast, the FUPA component is negative for hydrated alcohol because its price, which is fixed at 75% of gasoline price, is not sufficient to cover purchase and transport cost. Since the market of the second type is predominant, the final balance of FUPA is negative. The compensation of FUPA components is made by DNC to PETROBRAS and the distribution companies, within a fund called "Conta Alcohol". This mechanism leads to two types of subsidies:

(i) From consumers of anhydrous alcohol to consumers of hydrated alcohol.

(ii) From consumers of anhydrous alcohol close to supply sources to other remote consumers.

(iii) Furthermore, it is stipulated (Resoluçao CNP-18/84) that in case of insufficiency of FUPA, excess costs could be compensated by FUP components, which correspond to a possible subsidy from gasoline consumers (positive FUP component) to hydrated alcohol consumers.

It is noted that above mechanism has been the basis of development for the alcohol program in Brazil, known as "Proàlcool".

The Consolidation of Subsidy Funds

3.56 The compensation mechanism for the different types of subsidies leads to a number of operations between PETROBRAS, the distribution companies and DNC, which are registered in the following three Accounts:

Conta Derivados for the FUP
Conta Alcool for the FUPA
Conta Petroleo for difference between the cost of imported and domestic crude oil.

3.57 Practically, the FUP and FUPA components contained in product prices (gasoline, diesel oil, LPG, jet fuel) generate resources to compensate PETROBRAS and distribution companies, through transfers made by DNC. These resources are recovered by PETROBRAS. Companies are obliged to submit monthly statements to DNC concerning their costs incurred for transporting petroleum products, and which are reimbursed by

DNC with the funds coming from PETROBRAS. The remaining part of the funds allows PETROBRAS to cover its own transport costs and the final balance , positive or negative, is cumulated for the next month.

3.58 These three accounts show each month a series of receipts and expenses as presented in Annex 3.4 (Table 4). These show clearly the weight of each component of receipts and expenses and the utilization of FUP components as a resource for the "Conta Alcool". At the time of the gas sector mission in 1993, the monthly average balance of the three accounts was:

Conta Derivados	positive balance of US$14.4m
Conta Alcohol	negative balance of US$20m
Conta Petroleo	negative balance of US$71.3m
Total	negative balance of US$76.9m

3.59 The evolution over the last ten years of the three accounts is shown in Annex 3.4, (Fig. 1), with levels of subsidies on individual petroleum products shown in Annex 3.4 (Fig. 2). This illustrates a critical issue faced by Brazilian Government, which is that the total cumulated deficit by 1993 was US$3.3 billion, which includes 2.55 billion from the "Conta Petroleo" and 0.73 billion from the "Conta Alcohol" (measured according to official accounting). The cumulated deficit would be still higher (US$5.6 billion) if the opportunity cost of capital for PETROBRAS was taken at international rate.

3.60 The transfer of subsidies between consumers of different petroleum products is summarized in Table 3.4, based on data obtained in 1993. This shows that total cross subsidies including FUP and FUPA amounted to about US$180 million/month (generated mainly by gasoline and diesel oil), and a direct subsidy from the difference of domestic and import crude oil cost of about US$42 million/month. The major beneficiaries were LPG and alcohol consumers who each absorbed about 26% of transfer funds. The geographical equalization of prices corresponded to 23.5% of transfers. It is noted that the total subsidies paid by consumers differs from the total received by consumers by US$2.1 million. This is because the real expenses of the companies and PETROBRAS are recorded at the end of each month and may be different from the initial forecast.

Table 3.4 Petroleum Product Consumer Subsidy Transfers

	CROSS SUBSIDIES (mUS$/month)			
	From Precio Realiz'n	From FUP & FUPA	Product Subsidy	% Total Subsidy
Paid by Users of:				
- Gasoline	65.6	28.5	94.1	53.4
- Diesel Oil	7.0	65.6	72.6	41.2
- Lube Oils	-	9.6	9.6	5.4
- TOTAL	72.6	103.7	176.3	100
Received by Users of:				
- LPG	- 32.5	- 15.2	- 47.7	26.7
- Fuel Oil	- 17.9	-	- 17.9	10.1
- Naphtha	- 15.7	- 2.2	- 17.9	10.1
- Jet Fuel	- 6.5		- 6.5	3.6
- Alcohol	-	- 46.3	- 46.3	26.0
- Remote Consumers	-	- 42.0	- 42.0	23.5
- TOTAL	- 72.6	- 105.8	- 178.4	100

Source: PETROBRAS and World Bank Estimates - 1993 Gas Sector Mission

Proposed Modifications to the Existing Pricing System.

3.61 ***System deficiencies*** The current system of petroleum products and alcohol prices is clearly far from an economically efficient system, although most of its mechanisms were established to meet macroeconomic and social objectives such as:

Protection of low income consumers (subsidy to LPG)
Improvement of industry competitivity (subsidy to fuel oil)
Promotion of regional development (price equalization)
Improvement of oil self sufficiency (subsidy to alcohol)

The system presents two major drawbacks:

(i) Cross subsidies are measured against a uniform value of petroleum products (uniform VMR), ignoring the fact that intrinsic value of these products ex refinery is clearly indicated by international price structures. This has two negative effects. Firstly it gives a distorted idea of real economic subsidies applied to petroleum products and may lead to wrong decisions in tariff adjustments. It also provides to the refining sector a distorted signal concerning the investments required to improve real product valorization and refinery profitability.

(ii) The direct subsidy corresponding to the difference between cost of imported and domestic crude oil (accounted for in Conta Petroleo) has two consequences. It lowers the average price of refined products and maintains them under their economic price (considered as efficient price).

It also reduces PETROBRAS refining profitability and its capacity to invest (Conta Petroleo represents about US$700m/yr.).

3.62 **Proposed Modifications.** Evolution of the system towards improved economic efficiency has already started and can be progressed within several steps:

(i) Pursue the process of price disequalization.

(ii) Change the reference for applying cross subsidies, by substituting to the uniform VMR a set of differentiated VRi for each refined product. The VRi should be calculated to meet two conditions. Firstly, the VRi should reflect the international structure of petroleum products (US Gulf Coast for example). Secondly, the weighted sum of VRi by volumes of products refined should be equal to the VMR and thus cover refinery expenses.

(iii) Suppress negative subsidies on liquid fuels (subsidies vis-à-vis economic prices as calculated in step (ii)), this having a direct impact on natural gas penetration. Positive subsidy to gasoline may be maintained due to its link with the management of the alcohol program, and the macroeconomic implications of tackling this program.

(iv) Suppress the direct subsidy to crude oil cost, which will have the unavoidable consequence of raising all petroleum product prices. At this stage, and in order to limit price increases, the refinery margins may be reduced, and some low complexity refineries not adapted to the market could be closed. This would correspond to an overall improvement of the efficiency of the refinery sector, by focusing on more profitable complex refineries, and importing low cost products.

(v) Apply the full liberation of all petroleum product prices which would automatically shift towards their economic prices, but this would be possible only within a modified institutional context allowing free imports of petroleum products

Recommendations for Petroleum Products Pricing Reform

3.63 The main objective of the energy pricing reform is to progressively bring the prices of energy products into line with their economic costs, that is to say in line with international prices for petroleum products and natural gas, so that optimum penetration of natural gas in a competitive energy market may be encouraged. This means elimination of all kinds of subsidies, including cross subsidies applied to petroleum products and alcohol, and of direct subsidies applied to crude oil imports. For natural gas to be able to compete efficiently in the market, it will be necessary to eliminate the price distortions on competing fuels and move to full deregulation as quickly as possible. The highest priority is the *full deregulation of petroleum product prices which needs to be*

implemented as quickly as possible. This will require the following actions for which Constitutional Amendment No. 9 has removed the constitutional barriers:

(i) Revise the reference scale for ex refinery prices, replacing the value of products realization prices by a set of ex-refinery prices in line with international prices (import or export parity border price based on US Gulf). This would lead to a true appreciation of petroleum product subsidies and their correction.

(ii) Eliminate the crude oil subsidy. This means an increase in the general level of petroleum product prices to bring them in line with economic prices. This will allow ex-refinery prices excluding tax of all petroleum products to be set at parity with their economic prices.

(iii) Eliminate the cross subsidies (including differential taxation distortions) applied to products in competition with natural gas. This means price adjustments which may be compensated by a direct temporary subsidy to consumers where appropriate for social reasons, as is already applied for consumers of LPG. The fuels taxation system should not unduly penalize any single fuel, including natural gas.

(iv) Free up the imports and exports of petroleum products allowing access by independent importers and exporters to the liquid fuels distribution infrastructure. This is necessary for the deregulation of petroleum product prices.

(v) In order to fully internalize the environmental benefits of natural gas in its relative price, consider the application of a pollution tax to all hydrocarbon fuels depending on their propensity to pollute. This would penalize low quality fuels such as high sulfur fuel oil, in line with more stringent environmental regulation, and would promote the development of natural gas in an economically efficient way. The practicability of this approach should be evaluated against the effectiveness of the existing system of warnings and penalties for industries which fail to meet the existing air quality and emissions standards, and the impact on the incentives for consumers to fit gas cleanup equipment.

3.64 It is noted that several countries impose a tax which penalizes the burning of dirty fuels. For example, Sweden imposes a carbon dioxide tax on heavy fuel oil used by industry. There is also a Sulfur tax on fuel oil with higher than 0.1% S, which is 27 Swedish Kroner (about US$4) per cubic meter for every 0.1% increase in Sulfur content. Fuel oil with higher than 1% Sulfur is not allowed on the Swedish market.

4. ENERGY SECTOR INSTITUTIONS AND REGULATION

A. Introduction

4.1 The gas sector in Brazil has been traditionally subordinated to the oil sector. Until recently, little attention was paid to the organizational requirements which would encourage the efficient development of natural gas. This is rapidly changing with the prospects for the importation of Bolivian gas. A large section of industry is now eager to secure a share of the imported gas, and this has pushed the various participants in the gas sector to play a more active role in its future development. Funding the gas sector development will depend on access to domestic and foreign capital, and a condition for such investment is a legal and regulatory framework for the gas industry which offers the prospect of stability, acceptable risk and reasonable rewards.

B. Institutional Arrangements and Responsibilities

4.2 The natural gas sector is dominated by PETROBRAS, and by the various government departments which supervise its activities. The states have the monopoly of gas distribution, which is exercised through various State gas distribution companies, with each company regulated by the State Secretariat of Energy. In the past, private sector participation was allowed in exploration of oil and gas through risk contracts, but since the 1989 Constitution, new risk contracts have not been allowed. However, the Constitutional Amendment No. 9 which was enacted on November 9, 1995, removed all constitutional barriers to private sector participation in oil and gas activities in Brazil. In addition, the Concession Law for Public Services was approved by Congress in February 1995, which spells out that all concessions for public services must be awarded under a competitive bidding process. These two events have greatly improved the possibilities for private sector investments in Brazil's oil and gas sector

4.3 The Federal Government offices charged with the responsibility of regulating the gas sector are: (i) the Ministry of Mines and Energy (MME), and (ii) the Ministry of Finance (MOF). Presidential Decree 507 of April 23 1992 established the functions of the MME. Through the National Secretariat of Energy, the MME has responsibilities which include the formulation and implementation of the national energy policy, and to guide and surveil the activities related to PETROBRAS. This mandate is carried out by the *Departamento Nacional de Combustiveis* (DNC) which is under the National Secretariat of Energy, and is the regulatory agency of the oil and gas sector. The DNC authorizes allocation of supply and proposes price increases of oil products. In fact the MOF, through their Secretariat of Economic Policy, is in charge of prices and tariffs of public and administrated goods.

4.4 Technical norms and safety standards are set at the national level through the *Associacao Brasileira de Normas Tecnicas* (ABNT). This institution follows procedures through announcements, publication of new standards and approval through its various

committees. There has been no government participation nor rigorous monitoring and enforcement of these standards for the gas industry by an independent agency.

4.5 The two largest gas distribution companies in Brazil are COMGAS (Sao Paulo) and CEG (Rio de Janeiro). Both were originally established as private sector companies to distribute manufactured gas, and are currently converting their networks to distribute domestic natural gas. The other industrial natural gas distribution companies along the north east coast are small in comparison, with BR Distribudora and GASPART each having about 40% of the capital in these companies. The distributing companies have formed the *Associacao Brasileira das Empresas de Gas* (ABEGAS) to prompt the Federal Government and PETROBRAS to solve the problems the distributors face in the areas of pricing and gas supply.

4.6 Although the State Secretariats of Energy approve gas price increases to final consumers, their effectiveness in regulating gas distribution has been small. This is because: (i) the State owns the distribution companies and has a close relationship with their administration; and (ii) the Federal Government controls the bulk supply price of gas from PETROBRAS to the distributors as well as final price of competing fuels. In 1995 the Secretary of Energy of Sao Paulo prepared a detailed proposal for an independent state regulatory commission which will approve gas and electricity tariffs (*The Comissao de Servicos Publicos de Energia* - CSPE). This will be submitted to the State legislative assembly for approval by during 1996.

4.7 There are associations of industrial users, including the *Associacao Brasileira de Grandes Consumidores Industriais de Energia* (ABRACE) and they make their concerns about pricing known to the government. Small residential consumers however have no association of this kind.

4.8 In July 1991, the Commission of Natural gas was created by Presidential Decree. The commission was presided over by the National Secretariat of Energy, and comprised several government departments of the sector, PETROBRAS, ELETROBRAS, ABEGAS and the National Confederation of Industry. They completed their study in March 1992, arriving at the following conclusions: (i) domestic production is too small to supply domestic demand, (ii) there is a need for an investment to enlarge the national gas reserves and secure gas imports, (iii) the activities in the sector should not be subsidized, (iv) a revision of existing pricing policy of energy sources is needed to eliminate subsidies and distortions, and (v) distribution of natural gas belongs the individual states of the union, while production, transport and import is the Federal Union's interest.

4.9 It is noted that the *Departamento Nacional de Aguas e Energia Eletrica* (DNAEE), which is part of the MME, used to define the levels and structure of the power tariffs but through Law 8631 (enacted on March 4, 1993), this power was reduced to the approval of tariff requests proposed by the utilities.

C. Current Gas Sector Regulation

4.10 The legal basis for the development of the natural gas sector is the Constitution of 1988, Article 177, which confers the monopoly to the Federal Government for: (i) exploration and exploitation of deposits of petroleum, natural gas and other fluid hydrocarbons (which are the property of the Federal Union under Article 20); (ii) refining of domestic and imported petroleum; and (iii) import and export of the products and basic derivatives resulting from the activities listed in (i) and (ii); and (iv) maritime transportation of crude oil of domestic origin and of petroleum derivatives domestically produced, as well as transport, via pipelines, of crude oil, its derivatives and of natural gas of any origin.

4.11 Until the enactment of the Constitutional Amendment No. 9 (see below), Article 177 essentially ratified the monopoly granted to PETROBRAS in an earlier special law. Under Law No. 2004 of October 3, 1953, which required that the Federal Union monopoly on petroleum activities were to be exercised through PETROBRAS (Article 2).

4.12 The separation of powers between Federal and State authorities is dealt with in the Constitution. Article 20.IX established that mineral resources, inclusive of those underground, are the property of the Federal Union. Participation of the States, the Federal District, Municipalities and Administration Organs of the Federal Union in the results of exploration of oil and natural gas in their territories or a financial compensation for this exploration were given through Article 20 paragraph 1. Article 22 confers exclusive powers to the Federal Government to legislate on mineral resources. The Constitution also asserts the common competence of the Federal Union, the States and the Federal District to legislate on tax matters (Article 24.I). However, Article 25 paragraph 2 states that the local services of gas distribution are within the States' competence, which may carry them directly or by means of concession to a state company. The new concession law now allows private companies to be awarded concessions for gas distribution by the state governments.

4.13 Under Article 176, a requirement was introduced that only Brazilians or Brazilian companies with national capital may carry out exploration for hydrocarbon resources under an authorization or concession arrangement. Article 171 of the Constitution defined the concept of a "Brazilian Company with National Capital" as one whose actual control is permanently exercisable, directly or indirectly, by individuals domiciled and residing in the country and legal entities of internal public law. "Actual control" is to mean the ownership of the majority of the voting capital and the legal and *de facto* exercise of the deciding power to manage its activities. This provision reflects the tone of economic nationalism which does not give an encouraging signal to foreign investors.

4.14 As mentioned above federal regulation is carried out through the MME and the MOF. Presidential Decree No. 507 of April 23, 1992 establishes the functions and responsibilities of the MME. According to this decree the National Secretariat of

Energy, which is under the MME listed in Annex 4.1. As part of the National Secretariat of Energy is the *Departamento Nacional de Combustiveis* (DNC), which is in charge, among others, of the functions (established through Presidential Decree 507) also listed in Annex 4.1

4.15 The Constitutional Amendment No. 9 was enacted on November 9, 1995. Through revisions to Article 177, this confers on the Federal Government powers to contract state-owned and private companies for the activities related to the petroleum monopoly, covering the research or exploration and prospecting or production of the oil reserves, including natural gas and other fluid hydrocarbons; the refining of Brazilian and foreign petroleum; the importation and exportation of crude petroleum and basic petroleum derivatives, as well as transportation, by means of a conduit, of crude petroleum, its derivatives, and natural gas of any origin. Although the amendment is vague on the issue of imports of natural gas, it is understood that its spirit is to permit natural gas imports by private and state entities. In addition, the Concession Law for Public Services was approved by Congress in February 1995, which spells out that all concessions for public services (including natural gas distribution) must be awarded under a competitive bidding process.

D. International Trends in Gas Sector Regulation

4.16 Decisions concerning the form of regulation best suited to bring about private investment in major gas sector development in Brazil can benefit from an examination of the experience of other countries in regulating their gas markets. For reference, the institutional and regulatory structures of the major gas industries in Europe and the USA are presented in Annex 4.2. However, it is important to note that Brazil's gas sector is at an early and critical stage of development, and the lessons drawn from the regulatory experiences of the more mature gas industries of Europe, North and South America must recognize this. In pursuing regulatory reform, the primary objective of the more mature industries has been to increase economic efficiency, whereas in countries with less developed industries the attraction of foreign capital is viewed as a high priority objective.

4.17. During the past decade, there has been a clear worldwide trend towards lighter regulation associated with "unbundling" of services and the separation of control of the vertical stages of the gas chain (production, transmission and distribution). This trend has emerged out of a realization that; (i) competition, where it can be introduced, is a better promoter of efficiency and rapid development than regulation, and that only the natural monopoly stages where there is no competition should be regulated, and (ii) regulators have found it very difficult if not impossible to regulate the activities of integrated gas concerns which, despite obligations such as the provision of open access, always tend to favor their own upstream or downstream activities through manipulation of their transmission and distribution activities, thus limiting the chances of their competitors. Furthermore, regulators are hindered by their own dependence on these integrated gas concerns for the provision of information which is critical to fair regulation. In many

countries, competition has been enhanced at the gas production and distribution stages. At the producer stage, independent gas producers are able to compete for clients by being allowed to freely negotiate supply contracts directly with large users or distribution companies - not only are regulators not intervening in the setting of producer prices, but they ensure that the producers have access to the necessary transmission infrastructure. Conversely, at the consumer stage, large clients are free to negotiate directly with producers of their choice and, if advantageous to themselves, to by-pass local distribution companies and connect directly to the transmission network. Because the transmission network is essentially a natural monopoly, regulators have found that the easiest and most effective way to allow the full impact of competition is to establish independent transmission companies which are not controlled by upstream or downstream interests. These companies charge a fee (approved by the regulators) which permits a fair return on their investment. Since the transportation of high gas volumes is their primary concern, they are impartial to all parties. An essential element in this structure is the separation of the gas transport and gas commodity business, with the transmission company acting as a transporter only, and not involved in the purchasing or selling of gas.

4.18 In North America, the emphasis has been on liberalization as a way of deregulating markets which were heavily regulated. In Europe, where state ownership and state participation have played a fundamental role in the growth of the natural gas industry, irrespective of whether the industry is primarily in state or private hands, the emphasis has been a more cautious one on loosening state responsibility for financing the energy sector. In France for example, the government commissioned a study from the Ministry of Industry in 1993 to investigate how to put more competition in the field of gas and electricity where technically possible. With respect to gas, the report argues that GdF should retain control over the provision of gas and this should be recognized by the priority award of import licenses. It supports the idea that large purchasers should be able to negotiate imports directly with international suppliers, and recommends that unbundling should be introduced to the extent of separating the integrated company's accounts, but not its management. In the UK, Competition law was invoked to review the structure of the privatized gas industry, and recommended greater competition in supply of gas to small consumers and separation of trading and transport functions. However, there has also been a growing appreciation of the benefits to be gained from greater efficiency in providing service to consumers. Experience has been gained not only in terms of enhancing competition by regulatory means but also in developing measures to ensure that the standards of service and quality of gas supplied are monitored.

4.19 The Federal character of Brazil's constitution will clearly play a major role in determining the form of regulatory framework chosen for its gas sector. Thus regulation will have to be implemented at two levels - Federal and State. It will also need to take account of the possibilities for abuse of monopoly power at the high pressure transmission level, and the guarantee of standards of service, fair pricing and quality of supply at the low pressure distribution level. There is thus a compelling argument for the

establishment of different regulators at the Federal and State levels, distinguished by scope of jurisdiction and functions.

E. The Scope for Gas Regulation in Brazil

4.20. In 1994 the Brazilian gas sector faced a number of strategic options concerning the structural development of the gas industry, and which would depend on the outcome of the then impending constitutional review. The World Bank draft report analyzed these options, and these are retained below since they provide an analytical focus particularly with respect to the benefits of open access in improving the competitive environment within the sector, and the features of a regulatory system which would be most suitable for in view of the outcome of the 1995 constitutional review.

4.21 It is essential to recognize that any regulation of Brazil's gas sector should be only the very minimum necessary to ensure: (i) the protection of captive consumers, (ii) that the market for natural gas and competing fuels works in a fair and competitive way, (iii) the prevention of the abuse of monopoly power at the natural monopoly stages, and (iv) the sector becomes attractive for domestic and foreign private sector investors.

4.22 The strategic options were presented in the form of three variants, as represented in Table 4.1. Option 1 presupposed no major changes with retention of the existing PETROBRAS monopoly on oil and gas and the State monopolies on gas distribution. Option 2 has three sub-options, representing erosion of the PETROBRAS monopoly on gas and elimination of the State monopolies on gas distribution. Option 3 presupposed elimination of all monopolies on gas and oil. Collectively, these options provide a framework in which to analyze the scope of regulatory reform in the gas sector.

Table 4.1 Options for the Industry Structure

Option 1 Retention of PETROBRAS and State Distribution Monopolies

	Imports	Production	Transmission	Distribution
PETROBRAS	X	X	X	
States:				
- COMGAS				X
- CEG				X
Other States				XX····

Option 2a No PETROBRAS Monopoly for Gas Imports and Transmission or State Monopolies for Distribution

	Imports	Production	Transmission	Distribution
PETROBRAS	X	X	X	
Others	XX···		XX····	
COMGAS				X
CEG				X
Other States				XX····
Private Concessions				XX···

Option 2b No PETROBRAS Monopoly for Gas Imports & Production or State Monopolies for Distribution

	Imports	Production	Transmission	Distribution
PETROBRAS	X	X	X	
Others	XX····	XX····		
COMGAS				X
CEG				X
Other States				XX····
Private Concessions				XX····

Option 2c No PETROBRAS Monopoly for Gas Imports, Production, Transmission or State Monopolies for Distribution

	Imports	Production	Transmission	Distribution
PETROBRAS	X	X	X	
Others	XX····	XX····	XX····	
COMGAS				X
CEG				X
Other States				XX····
Private Concessions				XX····

Option 3 No Monopolies on Either Gas or Oil

	Imports	Production	Transmission	Distribution
PETROBRAS	X	X	X	
Others	XX···	XX····	XX····	
COMGAS				X
CEG				X
Other States				XX····
Private Concessions				XX····

X: Represents the number of agents in each function.

4.23 For all of the options a common set of core regulations would be required, mainly relating to issues such as safety and standards of operation. Each option would require a varying degree of additional regulation depending on the characteristics of the option. The advantages, disadvantages, and degree of regulation required for each option, together with the scope of core regulation, are detailed in Annex 4.3. The major points are outlined below:

4.24 **Option 1 - No Change:** This scenario assumed retention of the PETROBRAS monopoly on import, exploration, production, transport and export of natural gas and competing fuels, with the states retaining their monopolies on distribution, and presented the most formidable obstacles to gas sector development. It offered the least attractive environment to both foreign and private investors because of the lack of certainty of fair market competition between gas and competing oil products, and because the Government could continue to intervene in price-setting at all stages. This also offered the risk of fuels prices being arbitrarily manipulated by the Government for macroeconomic or social reasons. With this option, a strong regulator would be required to prevent anti-competitive practices in the preferential allocation of gas supplies to favored consumers (since open access would not be allowed, with PETROBRAS retaining full ownership of the gas up to the point of ex-transmission), and unfair pricing practices to favor the interests of the competing oil sector if this optimizes overall returns to the oil and gas monopolist. At the distribution level, there would be the possibility of cross subsidization between captive and non-captive consumers. These drawbacks would create a high risk environment for potential investors.

4.25 This option would require the establishment of a legal framework and regulators for petroleum products and natural gas sectors, with gas regulation needed at both the Federal and State levels. The aim would be to establish regulators which are both strong and independent enough to counter the concentrated economic power of the monopolist and to watch for abuses of economic power as noted above. The gas regulators would be required to oversee the setting of gas prices at every level, including the domestic producer price, the transmission tariffs for imported and domestic gas, and the

distribution tariffs. In common with this and the other options considered below, the Federal regulator would decide on the procedure to set quality and service standards at the transmission level and to enforce their compliance. At the distribution level, this responsibility, as well as enforcing norms and standards at local level, would rest with the State regulators. A mechanism would be needed to process consumer complaints and permit consumer participation in the regulatory bodies. The petroleum regulator would need to ensure that the setting of ex-refinery product prices is reflective of international levels, and that the oil market is not manipulated to artificially favor neither gas nor oil.

4.26 Within the constraints of this scenario, a number of recommendations were made which would improve the competitive environment and transparency within the sector. These included the separation of the PETROBRAS oil and gas businesses through separate accounting, and separation of the PETROBRAS gas transport and merchant functions for transparency of pricing. Also the sole gas supplier (PETROBRAS) to be excluded from retaining any interest in distribution entities. According to the then current design (diameter) of the proposed Bolivia pipeline and the constraints imposed by the Constitution, the pipeline capacity would be fully booked by the PETROBRAS contract and open access in the conventional sense would not be applicable. To gain many of the benefits of a conventional system of open access, it was recommended that PETROBRAS should have the *obligation in law* and under the surveillance of the gas regulator, to transport gas directly contracted between buyers in Brazil and producers or sellers in Bolivia or Argentina through the levy of a pipeline transport charge, for unbooked capacities over the 8-16 MMCMD in the Bolivian supply contract. This would provide an opportunity for large gas consumers in Brazil to negotiate long term contracts directly with gas producers. This in turn would encourage gas development in both Brazil and Bolivia, and provide a driving force to keep the pipeline full. The absorption within the Brazilian market of the 16 MMCMD already agreed with Bolivia need not in any way be threatened, since this gas is relatively low cost by international standards and should be attractive to buyers if a rational fuels pricing policy is adopted. On the contrary, the first 8-16 MMCMD of firm sales contracts could be dedicated to the supply contract with Bolivia, with the spare capacity in the build-up years and thereafter available to other parties thereby offering the prospect of improving the financial viability of the whole pipeline project.

4.27 **Option 2: Relinquishment of PETROBRAS and State Monopolies on Gas:** This option assumed that gas monopolies at both State and Federal levels could be relinquished to varying degrees. These could be reflected in three sub-options with advantages and disadvantages as represented in Annex 4.3. Option 2a assumed that the PETROBRAS and State monopolies on gas imports, transport and distribution would be relinquished. Option 2b assumed the PETROBRAS and State monopolies on gas imports, production and distribution would be relinquished. Option 2c envisaged complete absence of the monopoly on gas production, imports, transmission and distribution. However all three sub-options assumed that the monopoly on petroleum products would be retained.

4.28 It was recognized that these sub-options had considerable advantages over Option 1. These included much less likelihood of the manipulation of oil to gas competition, the possibility to introduce of some gas to gas competition, and more incentives for the efficient development of domestic gas resources. Because of the lower levels of monopoly control, a lighter form of regulation would be required. Regulation of ex-refinery prices of oil products and prices for captive gas consumers would still be required, but prices to the very large gas consumers could be left to free negotiation. The primary role of the regulator would be to hear consumer complaints backed with the authority to enforce actions against the producers, transporters or distributors of gas should they find evidence of unfair discrimination against consumers.

4.29 Under this scenario new entrants engaged in importing, producing, transporting, distributing and trading in gas would be a possibility to varying degrees. Potential investors in transmission and distribution would look for substantial risk mitigation measures to safeguard their investments. To a large extent, this could be possible through (i) entering into long term contracts for the transport and distribution of gas with credible entities, and (ii) retention of operational control (as distinct from majority ownership) of their investments. They would also look for assured markets for natural gas, as free as possible from gas to gas and interfuel competition. Open access of the pipeline would become a possibility and could meet a reluctance of major potential private sector investors in the pipeline to lose control of capacity allocation, especially if these investors would also have ambitions to enter the downstream gas business. Potential investors in the distribution business could also express concerns that open access of the gas transmission systems may allow competitors access to the larger, more profitable consumers and would be likely to look for guarantees of minimum reserved pipeline capacity for extended periods.

4.30. At an early stage of the gas industry development, concession areas for distributors will have to be defined. In an undeveloped market, potential investors in distribution systems will take into consideration (a) whether gas consumers have a right to connect directly to the gas transmission network after the LDC's have already invested in networks to serve them; and (b) if gas consumers can buy gas (the commodity) directly from producers after the LDC's have entered into take or pay contracts with PETROBRAS. In a situation characterized by limited competition with partial or total vertical integration, where there is an obligation to supply the smaller less profitable consumers, the investors will probably aim to protect themselves against the risks that the supplier will skim off the most profitable consumers through unfair discrimination in prices or supply conditions. Here, the investors may seek territorial exclusivity and resist the right of by-pass for a period sufficient to realize a return their investments. In delineating this issue, it is noted that PETROBRAS on the one hand has a vested interest to ensure that all gas supplied from the import pipeline to LDC's is absorbed in the market to maintain the financial stability of the gas import project. On the other hand, PETROBRAS is currently seeking to expand its distribution activities and could be expected to pursue opportunities to directly connect up to supply profitable consumers. Whichever distribution regulations are adopted with respect to the competitive tensions in

gas distribution activities, they should include a mechanism which will ensure that the distribution cost of service offered to all consumers is consistent with efficient distribution operations, and avoid to create a controlling interest by PETROBRAS in gas distribution systems as this would reinforce their already dominant position in the gas chain. PETROBRAS will remain the dominant supplier of natural gas to the LDC's for some time to come and gas to gas competition will be weak. However, as soon as the prices of petroleum products are freed, the non-captive consumers of the LDC's will benefit from free interfuel competition since they are able in most cases to switch to alternative fuels if they see a commercial benefit. There are several approaches to regulating the activities of the distribution entities. One approach is to regulate their activities through a rate of return regulation while the distribution companies are becoming established, and thereafter encourage improvements of efficiency through a price cap form of regulation. The price cap approach offers the best incentive for the distribution company to increase efficiency of operations. These price caps could include a reference to the price of competing fuel, with a built in adjustment for progressive efficiency improvement, and a "cost pass through" allowance to reflect changes in gas input price. In order to avoid uncertainty, the precise definition of large industrial consumers in terms of load and supply pressure, and the issue of bypass, should be worked out and clearly defined during the detailed design of the regulatory system.

4.31 Without open access to the transmission systems, the conditions are put in place for the development of a highly integrated and non-transparent gas industry. Because of the emergent nature of the industry and the need to attract private sector capital, participation by particular investors in more than one link in the gas chain may be necessary, but every effort should be made to ensure that the transmitter neither controls the upstream nor the downstream stages. One approach is to preclude a majority investor in the transmission function from becoming the majority investor in other functions, such as gas distribution.

4.32 **Option 3: Relinquishment of All Monopolies on Gas and Oil:** This was considered the easiest system to regulate since the conditions are put in place for the development of a high degree of interfuel and gas to gas competition with prices set by the market. Although a gas regulator would still be required, his duties would lighter and focused on resolution of contract disputes, enforcement of concession contracts, overseeing transport tariffs and gas prices for captive consumers, control of abuse of monopoly power, and safety and standards of service for the gas industry.

4.33. There is now an opportunity to prepare an industry structure which will encourage private sector investment and lead to the development of an efficient gas industry through the exploitation of *interfuel competition* and ultimately *gas to gas competition*. However, the GOB will need to take the following actions if Brazil is to benefit from this potential:

(i) Ex-refinery prices of petroleum products in Brazil to be fully deregulated at the earliest opportunity (see above). This will create stable conditions

for *interfuel competition* where natural gas will have to compete in the market with alternative fuels which follow international prices.

(ii) Ensure that independent gas producers and importers are allowed Open Access to the Bolivia - Brazil pipeline (without possibility to undermine the 16 MMCMD under the existing contract - see below) and to the existing PETROBRAS gas transmission infrastructure where spare capacity exists. For future regional gas transmission lines within Brazil, if the developer chooses to construct excess capacity in the pipeline, then this excess capacity should be open for use by third parties under contract carriage terms which ensures the economic viability of pipeline transport operations. These obligations to make open access available will need to be included in the legislation and strongly enforced by the regulatory agency. This is essential for the development of *gas to gas competition* which will create the mechanism for price competition between domestic gas producers in Brazil, and between domestic gas producers in Brazil and gas importers. Open Access to gas transmission systems and private participation in upstream development will be a major driving force to control extraction costs and lead to increased supplies of domestic gas in Brazil. Open Access will also allow the development of gas to gas competition at the consumer level, by allowing *very* large consumers (such as power stations) and the LDC's the option to negotiate directly with a variety of producers and importers for the best commercial terms. This environment will encourage investors in upstream and downstream development in Brazil.

(iii) The active promotion of good prospective acreages for international competition and reduction of the dominance of PETROBRAS in domestic gas production is essential if gas to gas competition is to develop. These acreages may include new exploration blocks and also areas currently under exploration concession to PETROBRAS but which the company does not have the financial or human resources to develop. If only areas of high technical risk are made available, given the relatively high commercial costs and risks in Brazil, the investor's appetite for technical risk is greatly diminished. If domestic gas to gas competition is to be established the near term, the quickest way would be for PETROBRAS to divest itself of some of the existing gas production facilities in the South-South East. In any event, the preparation of a model upstream concession agreement which contains all the necessary contractual, legal, financial and commercial policy details is needed, and any existing geological and seismic data for the allowed drilling acreages should be made available to potential investors.

4.34. In order to allow new distribution companies to become established, the arguments outlined in Par. 4.30 apply. The re-negotiated agreement with YPFB gives

PETROBRAS the option to purchase, in preference to third parties, volumes of gas up to 30 MMCMD of Bolivian gas. There is no good reason for PETROBRAS to retain this exclusive option and very large consumers and LDC's in Brazil should have the opportunity to purchase volumes over and above the 8-16 MMCMD contract quantities directly from producers in Bolivia, PETROBRAS or independent producers in Brazil.

F. Regulatory Bodies

4.35 Whichever mix of companies proceeds with the construction and operation of the pipeline from Bolivia, the consortium will be subject to a single license and will have a dominant position in the market. The Federal Regulatory agency will have as one of its tasks the regulation of this corporate entity, monitoring its performance of the duties laid down in the license. At the state level, however, it is most likely that single companies will have the monopoly rights to distribute over discrete geographic areas. By means of a concession license, duties could be imposed by the state regulator on the distributor, such as an obligation to supply gas and requirements with respect to charges.

4.36 The Federal regulatory authority for Brazil can be either a government department or an independent agency. The experience of France, Spain and Italy shows that regulation or supervision can be carried by a government department or unit within a Ministry. In France such a role also involves the Ministry of Finance. However, the Federal structure of Brazil limits the relevance of the highly centralized gas regime such as the French one. In each of the above cases however, the relationship has been between a State company and a government department and in each case there has been a lack of transparency.

4.37 There is therefore a strong case to be made for the creation of an independent regulatory agency as has been attempted in Britain, Canada and Argentina. In Brazil's case, with a Federal structure and different interests with respect to the gas industry among the states, the structure would have to be one of federal and state regulatory bodies. With respect to its size, a small regulatory body is less likely to act as a bureaucratic brake on the emergence of a gas market than a large one might.

4.38 Preferably, the regulatory authority would comprise a Board headed by a president who would have to be approved by Congress. The members of the board should have fixed terms, without the possibly of removal from office unless found guilty of misconduct. The members of the board should be appointed at staggered intervals for a term of five to seven years by the Ministry responsible for the gas sector, the Ministry of Mines and Energy, and paid from a fund comprising levies on the gas industry. The president of the board should have the right to appoint the staff of the regulatory agency and when necessary to hire outside experts which would also be financed by the gas industry. Some independence from government is necessary to its credibility but this can be built into the procedures of appointment and tenure.

4.39 In designing a regulatory body, the emphasis would be on simplicity in its decision-making and not on a complex legal structure. The commission model has not worked well in this sense in the United States, leading to a cumbersome framework in which a great deal of litigation is normal. Part of the reason for this is the broad mandate of the US body.

G. Structure of the Laws and Regulations

The Regulatory Framework

4.40 The regulatory framework for gas would comprise the following principal components:

(i) A comprehensive Gas Act (or Hydrocarbon Law);

(ii) Subordinate legislation comprising rules and regulations on specific matters as mentioned in the Gas Act;

(iii) A model license (or concession or authorization) to transport or distribute gas which contains specific conditions to be fulfilled by the licensee company or companies;

(iv) A code of practice which stipulates standards of safety, performance and service;

(v) A regulation providing for the creation, funding, and functions of the regulatory agencies.

(vi) Responsibilities for granting concessions

4.41 The Gas Act should include such matters which would require the approval of the Congress, while providing for delegation of authority in specific matters to the appropriate Minister and regulatory agencies. It should contain the kind of provisions which are likely to have a degree of permanence once put in place. While the total structure should provide a balance between certainty and flexibility, the Act is the element which is most necessary to the provision of the former. It should not include matters which are likely to require modification in the light of experience or changing circumstances, but should include mechanisms by which these can be brought about. An example of this is the provision found in the British license to supply gas (called an authorization) which states that such licenses may be modified by agreement between the regulator and the licensee. This has proved a workable method of up-dating the provisions to reflect experience gained.

The Enactment of Legislation

4.42 A law (Gas Act) on the gas industry is required to provide a framework for the industry and to give a clear signal to potential investors and the public of the importance of the emerging gas industry to Brazil's energy sector. The law should be designed to interact with subordinate instruments such as regulations, codes of standards and most importantly the licenses to supply gas, which the law itself provides for. The law should give potential entrants into the market a clear message that a new industry is being encouraged, but that abuses of monopoly power will not be permitted.

4.43 The Gas Act should follow the example of similar laws around the world and a suggested framework is shown in Annex 4.4. It should contain the following provisions:

(i) A declaration that the gas sector is a matter of public interest to the State of Brazil which has authority under the Constitution to ensure that the supply of gas to consumers is reliable and carried out according to the appropriate standards of safety. This is not a mandate for state intervention. It can be drafted in such a way as to provide a message to investors and consumers. To potential investors it indicates that as a last resort the Federal Government will act to guarantee the development of the gas supply network from its current state to a fully functioning system. For such an important industry with an international dimension, it is impossible for the State not to take a significant interest and better to have some way of channeling it by law in directions which are market supportive than vice versa. To consumers the declaration gives a clear signal that gas is a dangerous substance when mishandled, and that consumers will tend to develop a high degree of independence upon their local supplier. In both cases this will require some supervision by the State. In Brazil's case, this means that some decisions will have to be taken with respect to the allocation of authority in these matters between the Federal and State levels in a manner compatible with the Constitution.

4.44 An example of the kind of text which could be adopted is the following: "It is declared that the supply of gas as well as the activities of production, transport and distribution relating thereto are a matter of public interest. In accordance with the Constitution, the State of Brazil reserves to itself the right to make provision for the supply of gas, including the activities of production, distribution and sale, either directly or indirectly, through the grant of licenses".

(ii) A prohibition on unauthorized supply, ensuring that no company may establish a gas business without being first scrutinized for its technical and financial capacity to do so;

(iii) Designation of the competence of the appropriate authorities, such as the Ministry of Industry and Energy and the Ministry of Environment.

Prospective licensees need to know to whom they should approach for award of a license and what the scope of authority of various Ministries is.

(iv) A procedure for award of licenses to supply gas, involving the imposition of obligations on licensed companies to provide a reliable supply of gas, to avoid undue discrimination and to conduct their operations in accordance with the public interest.

(v) A regulatory agency is to be established at Federal level and similar bodies at State level with a measure of consumers' protection to be provided by a gas consumers' council; the competence of these bodies to be set out, and its powers should include the power to give directions to the licensed companies; publication of its decisions with reasons given for them and the possibility of appeal against its decisions set out; as a last resort, the regulatory agency should have the power to resolve disputes between the suppliers and their customers.

(vi) Rights of the licensee to obtain access to land and the procedure governing this, designed to protect the rights of landowners and also to promote fast-track decision-making in an area which can cause expensive delays for investors;

(vii) Tariff principles to be outlined in the law but detail to be avoided;

(viii) Provisions to be included which will require the suppliers of gas to adopt the highest service and safety standards and to ensure that the quality of gas supplied is high;

(ix) Relationship between the Gas Act and competition law. In many countries this interaction is crucial to the working of the regime as a whole (Germany and the UK, for example); in the event of unfair competition or anti-competitive practices, the federal regulatory authority would have the right to intervene. However, experience shows that where a competition agency exists, such a body is capable of taking a wider view of competition and may be better able to play a supervisory role in matters which are complex and highly sensitive politically. At least, there should be some co-ordination requirement in the Gas Act;

(x) Enforcement powers granting authority to implement the Act to the regulatory agency in consultation with the Ministry.

(xi) Transitional provisions if required, including the requirement to review the possibilities for open access and mutual exclusivity of the gas transport and trading functions.

Regulations, Standards and Codes of Practice

4.45 On the basis of the framework of the Gas Act, regulations, standards and codes of practice would have to be developed. These would cover the entire spectrum of the gas industry relating to the transmission and distribution of gas, measurement, storage, operation and maintenance, appliances, equipment and installations for the industrial/commercial and domestic sectors. Many of these matters could be dealt with in a single broad gas supply regulation as in Spain. Such a regulation could be developed by the regulators, the existing standards organization and the Ministry.

4.46 Some matters could be best imposed by regulation but others not. To impose standards of service, for example, by means of a formal regulation may remove from the company the initiative to constantly improve the provision of services. Such initiative should be encouraged. However, there should also be powers available to the regulator to seek a regulation through the Minister to impose standards of service on the utility if he thinks it necessary.

4.47 The standards of service has emerged as an important subject in European energy regulation. By this is meant the provision of gas supplies, calculation of gas supplied, recovery of gas charges, prevention of gas escapes and so on. The British experience suggests that the regulator should be given a duty to promote the efficient use of gas and the powers to enable standards of performance to be set governing the promotion by the utility of the efficient use of gas. Some standards may even be designated as key standards such as those covering the restoration of supply in the event of an interruption. Such standards need not necessarily be framed broadly; they can be defined in such a way as to be quantifiable, capable of being monitored and may represent a significant element of cost. In this respect the experience of the British Office of Gas supply is useful. The regulatory body should also have the power to require information on these matters and the right to publish such information for consumers. Such an approach has been adopted in the UK gas and electricity sectors with respect to the regulators' powers to set standards of performance. French experience on this matter is a little different in terms of approach. The same concerns figure largely in the *Contrat d'Objectifs* between the State and Gaz de France for 1991-1993.

4.48 Some activities are best approached via a Code of Practice, developed largely by the gas industry itself. For example, the UK has codes on Energy Efficiency and also on the installation of gas appliances which includes certification of individual fitters of gas appliances.

Gas Licenses

4.49 Under the Gas Act there should be a requirement that the transmission and distribution companies will each require a license to carry on a gas supply business. This is normal practice in countries as different as Belgium, the Netherlands, Germany, Spain, and - combined in a single license - the UK. Among the specific conditions which will be

included are the following: Distribution licenses would require a full description of any obligation placed on the utility concerning the required levels of investments, lengths of networks, consumer connections, and so on; levels of customer service to be achieved, with respect to connection applications, meter reading and billing performance, arrangements for dealing with customers with special needs such as the disabled; meter provisions; methods of calculating charges to be levied on customers for connection to the system and a stated policy on cross-subsidization. Both transmission and distribution licenses would include control of gas quality by determining specifications and accepted tolerance margins; requirements for standards and safety including provisions that are mandatory for flow of information between licensees and regulators; the regulators' right to monitor safety practices; responsibilities to ensure security of supply and requirements to submit accounts and other information which the regulators may need.

H. Recommendations

4.50 It is recommend to set up a regulatory system for gas comprising the following principal components:

(i) A comprehensive gas Gas Act (or Hydrocarbon Law);

(ii) Subordinate legislation comprising rules and regulations on specific matters as mentioned in the Gas Act;

(iii) A model license (or concession or authorization) to transport or distribute gas which contains specific conditions to be fulfilled by the licensee company or companies;

(iv) A code of practice which stipulates standards of safety, performance and service;

(v) A regulation providing for the funding of the regulatory agencies.

(vi) Responsibilities for granting concessions.

A basic law (Gas Act) on the gas industry is required to provide a framework for the industry and to give a clear signal of the importance of the emerging gas industry to Brazil's energy sector.

It is also recommended to:

(i) Separate of the PETROBRAS gas production, transport and merchant functions through separate accounting for transparency of pricing

(ii) Award distribution concessions through a system of open bidding;

(iii) Ensure that independent gas producers and importers are allowed Open Access to the Bolivia - Brazil pipeline (without possibility to undermine the 16 MMCMD under the existing contract - see below), and to the existing PETROBRAS gas transmission infrastructure where spare capacity exists. For future regional gas transmission lines within Brazil, if the developer chooses to construct excess capacity in the pipeline, then this excess capacity should be open for access to third parties under contract carriage terms which ensures the economic viability of pipeline transport operations. These obligations to make spare capacity available to open access will need to be included in the Legislation.

(iv) Currently, PETROBRAS has 51% equity in the Bolivia Brazil pipeline project and controls the existing gas transmission lines in Brazil. Under the current circumstances, PETROBRAS retains the control of imported Bolivian gas and could remain the dominant domestic producer for some time to come. In this case PETROBRAS or its subsidiaries should be excluded from gaining majority control of any gas distribution company.

4.51 With respect to the form of regulation for the transmission and distribution entities:

(i) In order to provide incentive for the transmission company to operate the Bolivia pipeline as full as possible and to reduce costs, consider the control transport tariff by a price cap regulation;

(ii) There are several approaches regulating the distribution entities, and the best approach would need to be worked out during the detailed design of the regulatory framework. One such approach could be to regulate their activities through a rate of return during the period while markets are being developed. Then, after the market development phase, use a price capping formula to provide the companies incentives for cost reduction, while leaving them the required flexibility in their marketing policy.

ANNEXES

CONSOLIDATED ENERGY BALANCE YEAR 1994 UNITY: 10^{-3} toe

ACCOUNT	PETRO-LEUM	NATUR. GAS	STEAM COAL	METAL. COAL	URAN. U3O8	HYDRA-ULIC	FIRE-WOOD	S.CANE PRODUC.	OTHER PRIMAR.	TOTAL PRIMAR.	DIESEL OIL	FUEL OIL	GASO-LINE	LPG	NAPH-THA	KERO-SENE	GAS	COAL COKE	URAN. C/UO2	ELECT-RICITY	CHAR-COAL	ALCO-HOL	OTHER OIL P.	N.ENER. OIL P.	BITU-MEN	TOTAL SECOND.	TOTAL
PRODUCTION	33803	7508	1947	33	0	70446	24110	21357	3105	162309	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	162309
IMPORTS	27910	0	0	8370	0	0	0	0	0	36280	2761	2729	23	1875	2507	341	0	1001	0	9181	4	936	35	71	0	21464	57752
CHANGES IN STOCKS	3171	0	-9	-114	0	0	0	0	0	3048	-204	-530	-205	-542	-534	35	0	-46	0	0	0	-335	-16	110	0	-2267	781
TOTAL SUPPLY	64892	7508	1938	8289	0	70446	24110	21357	3105	201645	2557	2199	-182	1333	1973	376	0	955	0	9181	4	601	19	181	0	19197	220842
EXPORTS AND BUNKERS	0	0	0	0	0	0	0	0	0	0	-907	-3087	-2314	0	0	-649	0	0	0	0	-7	-145	0	-162	0	-7271	-7271
NON-UTILIZED	0	-1044	0	0	0	0	0	0	0	-1044	0	0	0	0	0	0	-9	0	0	0	0	0	-120	0	0	-129	-1173
RE-INJECTION	0	-1467	0	0	0	0	0	0	0	-1467	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1467
GROSS DOMESTIC SUPPLY	64892	4997	1938	8289	0	70446	24110	21357	3105	199134	1650	-888	-2496	1333	1973	-273	-9	955	0	9181	-3	456	-101	19	0	11797	210931
TOTAL TRANSFORMATION	-64892	-1298	-1082	-8029	0	-70446	-10597	-7062	-898	-164304	21638	11022	11547	4673	3952	2430	1500	5626	0	75598	5349	6273	3775	3040	260	156683	-7621
PETROLEUM REFINERIES	-64892	0	0	0	0	0	0	0	-428	-65320	22213	11858	11324	3922	5338	2430	0	0	0	0	0	0	3124	3040	0	63209	-2071
NATURAL GAS PLANTS	0	-830	0	0	0	0	0	0	256	-574	0	0	0	559	0	0	0	0	0	0	0	0	0	0	0	559	-15
GASIFICATION PLANTS	0	-133	0	0	0	0	0	0	0	-133	0	0	0	0	-77	0	201	0	0	0	0	0	0	0	0	124	-9
COKING PLANTS	0	0	0	-8029	0	0	0	0	0	-8029	0	0	0	0	0	0	1464	5626	0	0	0	0	0	0	289	7379	-650
NUCLEAR CYCLE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PUBL. UTIL. POWER PLANTS	0	-8	-1041	0	0	-69369	0	0	0	-70418	-541	-425	0	0	0	0	0	0	0	71222	0	0	0	0	0	70256	-162
SELFS PROD. POWER PLANTS	0	-131	-41	0	0	-1077	-176	-469	-860	-2754	-93	-411	0	0	0	0	-165	0	0	4376	0	0	-182	0	-29	3496	742
CHARCOAL PLANTS	0	0	0	0	0	0	-10421	0	0	-10421	0	0	0	0	0	0	0	0	0	0	5349	0	0	0	0	5349	-5072
DISTILLERIES	0	0	0	0	0	0	0	-6593	-38	-6631	0	0	0	0	0	0	0	0	0	0	0	6273	0	0	0	6273	-358
OTHER TRANSFORMATIONS	0	-196	0	0	0	0	0	0	172	-24	59	0	223	192	-1309	0	0	0	0	0	0	0	833	0	0	-2	-26
LOSSES IN DISTRIB./STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-29	-34	0	-12131	-210	0	0	0	0	-12404	-12404
FINAL CONSUMPTION	0	3699	856	260	0	0	13513	14295	2207	34830	23288	10134	9051	6006	5925	2157	1462	6547	0	72648	5136	6729	3674	3059	260	156076	190906
FINAL NON-ENERGY CONSUMPTI	0	959	0	0	0	0	0	0	0	959	0	0	0	0	5925	0	0	0	0	0	0	470	211	3059	42	9707	10666
FINAL ENERGY CONSUMPTION	0	2740	856	260	0	0	13513	14295	2207	33871	23288	10134	9051	6006	0	2157	1462	6547	0	72648	5136	6259	3463	0	218	146369	180240
ENERGY SECTOR	0	919	0	0	0	0	0	7393	0	8312	348	1360	0	19	0	23	388	0	0	2342	0	0	2061	0	0	6541	14853
RESIDENTIAL	0	26	0	0	0	0	6658	0	0	6684	0	0	0	5471	0	75	110	0	0	16227	502	0	0	0	0	22385	29069
COMMERCIAL	0	11	0	0	0	0	90	0	0	101	68	289	0	126	0	2	40	0	0	8375	57	0	1	0	0	8958	9059
PUBLIC	0	7	0	0	0	0	1	0	0	8	180	369	0	42	0	8	6	0	0	6224	3	0	17	0	0	6849	6857
AGRICULTURE	0	0	0	0	0	0	1824	0	0	1824	3909	61	0	1	0	0	0	0	0	2379	6	0	0	0	0	6356	8180
TRANSPORTATION - TOTAL	0	39	0	0	0	0	0	0	0	39	18318	922	9051	0	0	1991	0	0	0	341	0	6259	0	0	0	36882	36921
HIGHWAYS	0	39	0	0	0	0	0	0	0	39	17379	0	9002	0	0	0	0	0	0	0	0	6259	0	0	0	32640	32679
RAILROADS	0	0	0	0	0	0	0	0	0	0	561	0	0	0	0	0	0	0	0	341	0	0	0	0	0	902	902
AIR TRANSPORTATION	0	0	0	0	0	0	0	0	0	0	0	0	49	0	0	1991	0	0	0	0	0	0	0	0	0	2040	2040
WATERWAYS	0	0	0	0	0	0	0	0	0	0	378	922	0	0	0	0	0	0	0	0	0	0	0	0	0	1300	1300
INDUSTRIAL - TOTAL	0	1738	856	260	0	0	4940	6902	2207	16903	465	7133	0	347	0	58	918	6547	0	36760	4568	0	1384	0	218	58398	75301
CEMENT	0	5	392	0	0	0	1	0	41	439	15	1079	0	0	0	0	0	0	0	886	203	0	4	0	4	2191	2630
PIG-IRON AND STEEL	0	380	9	260	0	0	0	0	0	649	39	369	0	50	0	10	902	6206	0	4198	3748	0	0	0	214	15736	16385
FERRO-ALLOYS	0	0	0	0	0	0	12	0	0	12	0	0	0	0	0	0	7	38	0	1920	445	0	0	0	0	2410	2422
MINING/PELLETIZATION	0	80	0	0	0	0	0	0	0	80	142	616	0	1	0	2	0	110	0	1769	3	0	2	0	0	2645	2725
NON-FERROUS/OTHER META	0	121	0	0	0	0	39	0	0	160	0	425	0	20	0	0	1	193	0	8733	123	0	454	0	0	9949	10109
CHEMICAL	0	439	122	0	0	0	179	50	0	790	64	1331	0	17	0	23	0	0	0	4435	29	0	891	0	0	6790	7580
FOODS AND BEVERAGES	0	154	88	0	0	0	1778	6813	0	8833	30	846	0	26	0	9	5	0	0	3521	0	0	0	0	0	4437	13270
TEXTILES	0	78	3	0	0	0	103	0	0	184	2	377	0	3	0	1	0	0	0	1991	1	0	0	0	0	2375	2559
PAPER AND PULP	0	90	115	0	0	0	789	31	2121	3146	20	685	0	8	0	2	0	0	0	2974	0	0	25	0	0	3714	6860
CERAMIC	0	101	73	0	0	0	1474	0	45	1693	7	894	0	129	0	2	0	0	0	545	5	0	0	0	0	1182	2875
OTHER	0	290	54	0	0	0	565	8	0	917	146	911	0	93	0	9	3	0	0	5788	11	0	8	0	0	6969	7886
UNIDENTIFIED CONSUMPTION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ADJUSTMENTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ANNEX I.1
Page 1 of 1

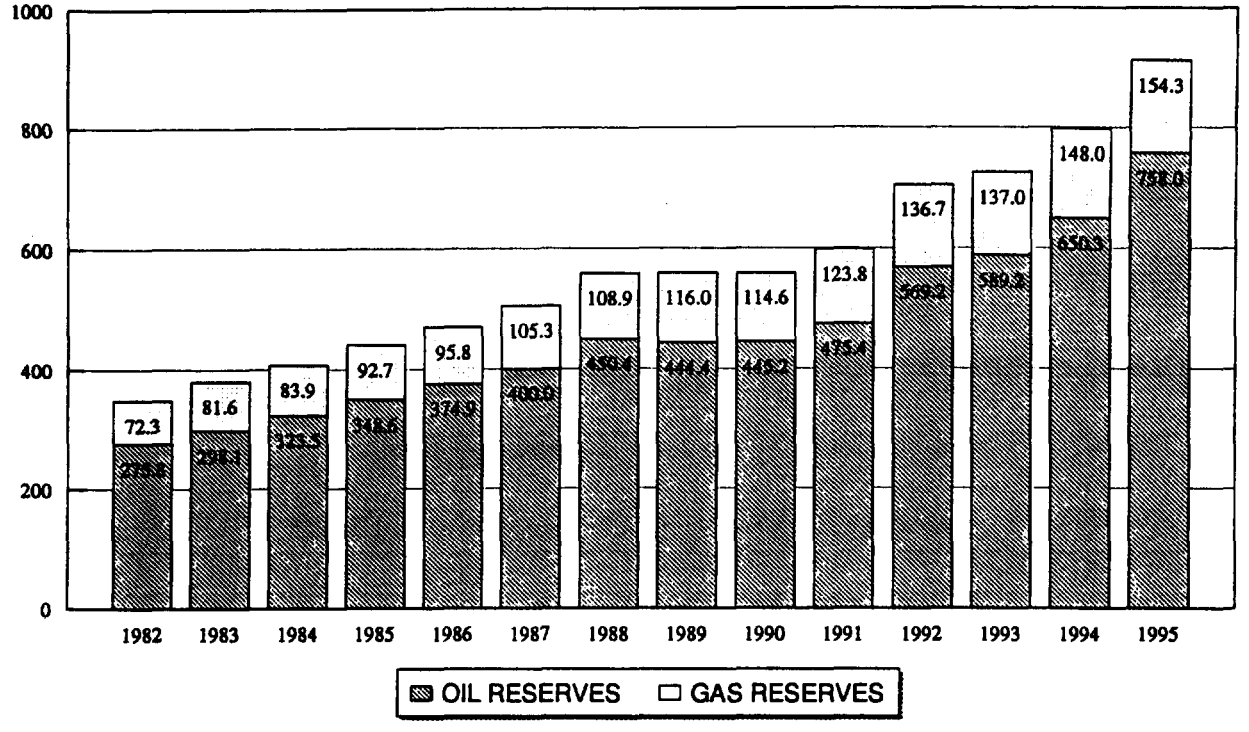
ANNEX 2.1

NATURAL GAS RESERVES AND PRODUCTION PROSPECTS

Fig. 1

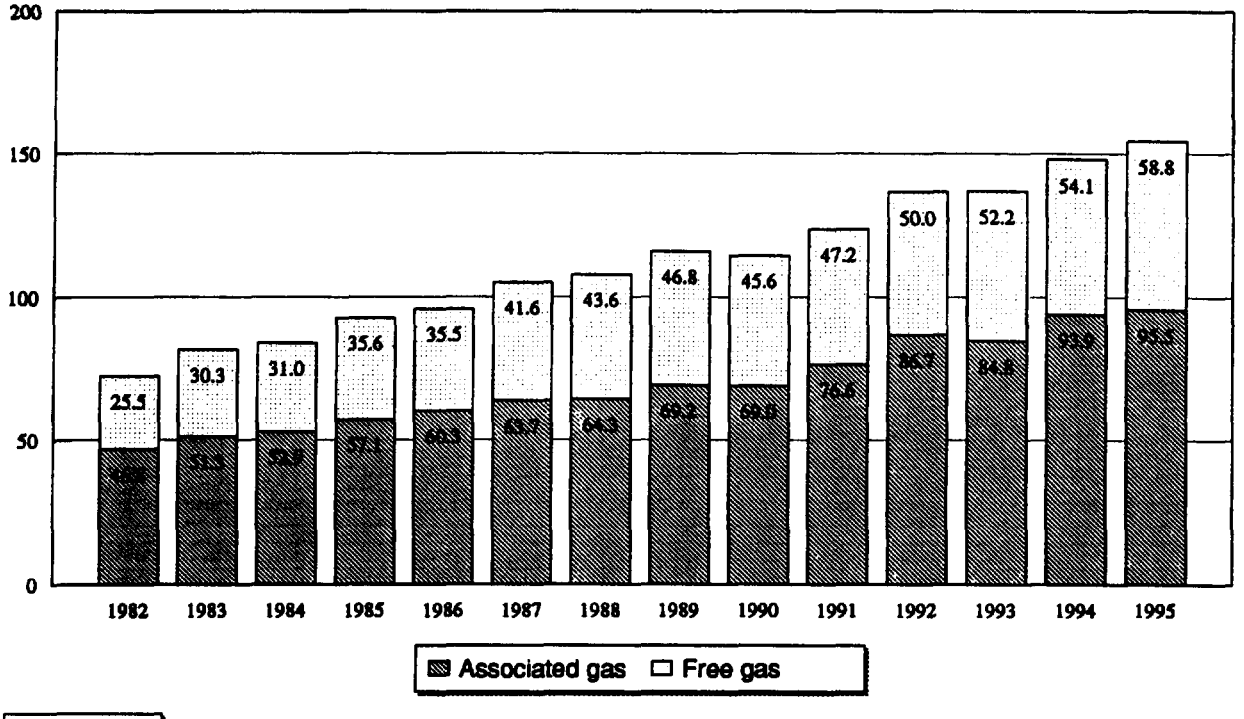
Evolution of Hydrocarbon reserves in Brazil

Oil and Gas in Billion M3



Evolution of Natural Gas reserves in Brazil

Associated and free gas in Billion M3

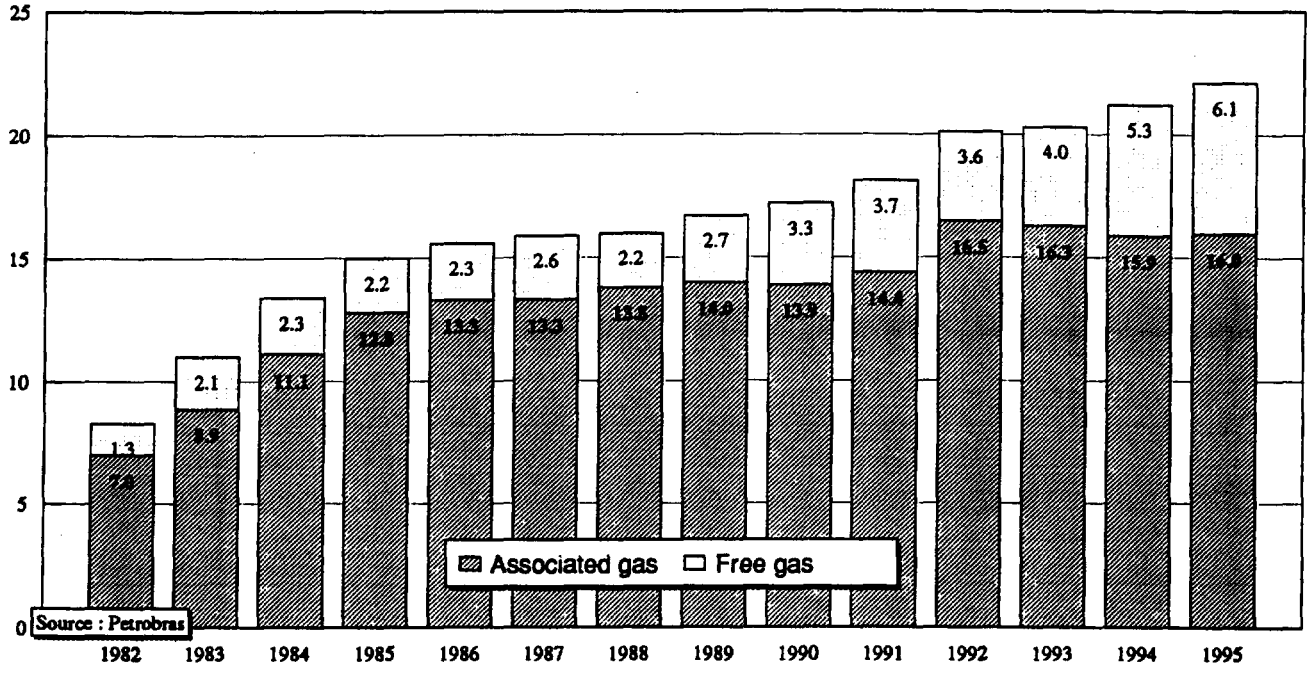


Source : Petrobras

Fig. 2

Evolution of Natural Gas production in Brazil

Associated and free gas in Million M3/day



Gas production by region in 1995

Associated and free gas in 1000 M3/day

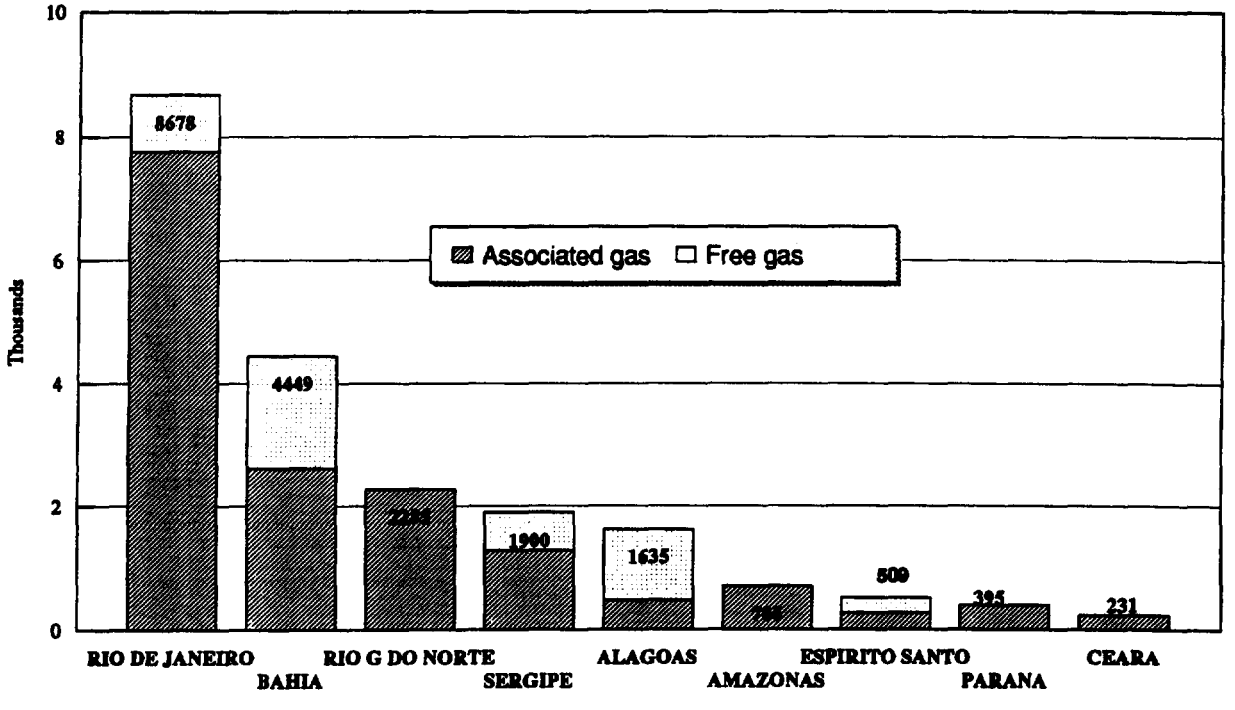


Fig.3 NATURAL GAS RESERVES AND GAS AVAILABLE FOR SALES

Unit: Billion M3 (BCM)

	GAS RESERVES (1)				AVAILABLE FOR SALES (2)		
	PROVEN	PROBABLE	POSSIBLE	TOTAL	EXISTING FIELDS	NEW DISCOVER.	TOTAL
AMAZONAS	15	15	12	42	25,2	19,3	44,6
NORTH EASTERN	52	10	6	68	34,4	34,2	68,6
incl. Ceara	1			1	0,3	0,4	
Rio Grande do Norte	8	6	1	15	6,4	16,9	
Alagoas	13	1		14	5,5	4,2	
Sergipe	4			4	6,8	3,8	
Bahia	26	3	5	34	15,4	9,0	
SOUTH EASTERN	57	35	8	100	51,9	93,6	145,5
incl. Sao Paulo	7	6		13	17,7	25,9	43,6
Rio de Janeiro	46	28	8	82	30,2	12,8	42,9
Espirito Santo	3			3	2,4	1,0	3,4
Parana	1	1		2	1,7	53,9	55,6
TOTAL	124	60	26	210	111,5	147,2	258,7
TOTAL Exclud. Amazonas	109	45	14	168	86,3	127,8	214,2

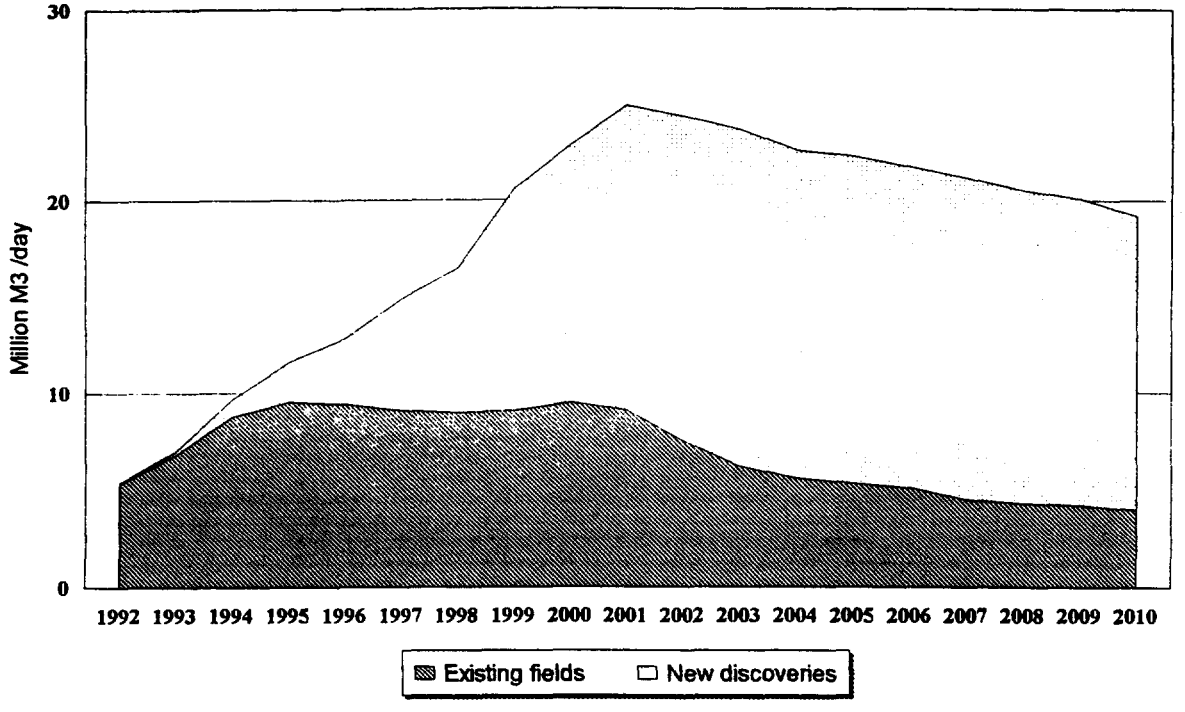
Sources : PETROBRAS , and World Bank evaluation of gas available for sale.

(1) Reserves as of Jan. 1993. By Dec. 1995 Proven Reserves were 154 BCM, and Total Reserves about 230 BCM.

(2) Gas available for sales cumulated over the period 1993-2015.

Fig.4

South East Brazil - Gas available for sale



STATES OF SAO PAULO, RIO DE JANEIRO, PARANA, SANTA CATARINA

Total Brazil - Gas available for sale

PETROBRAS PROJECTIONS

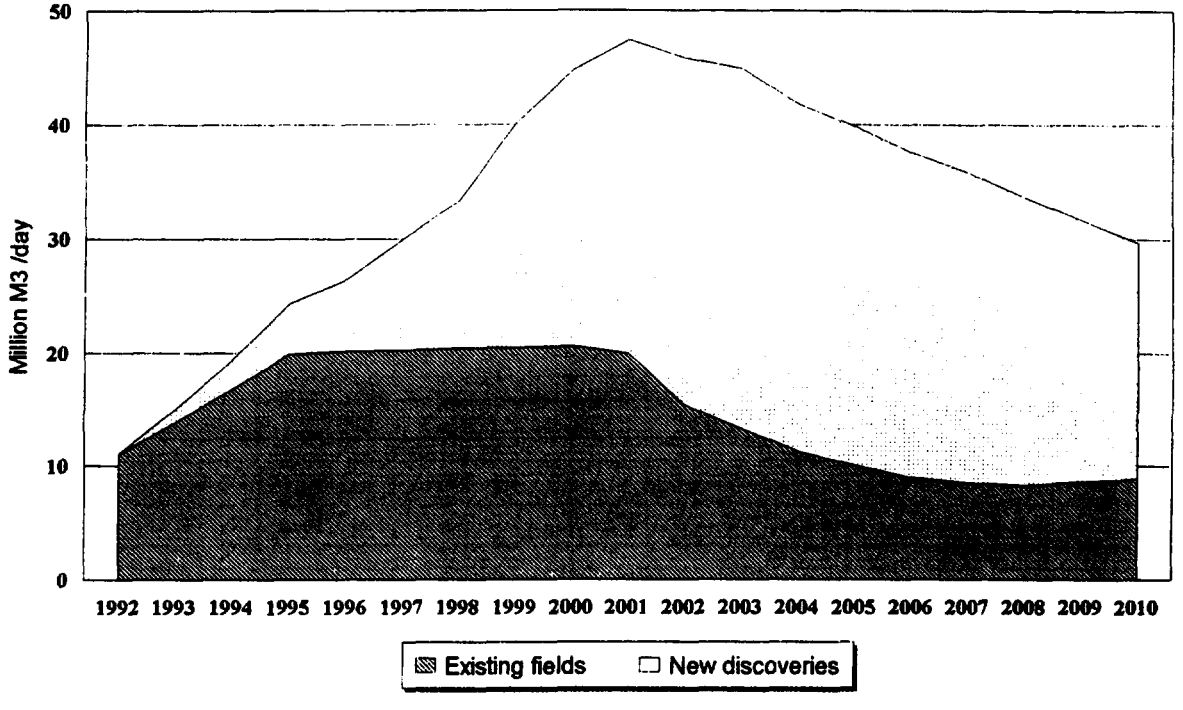
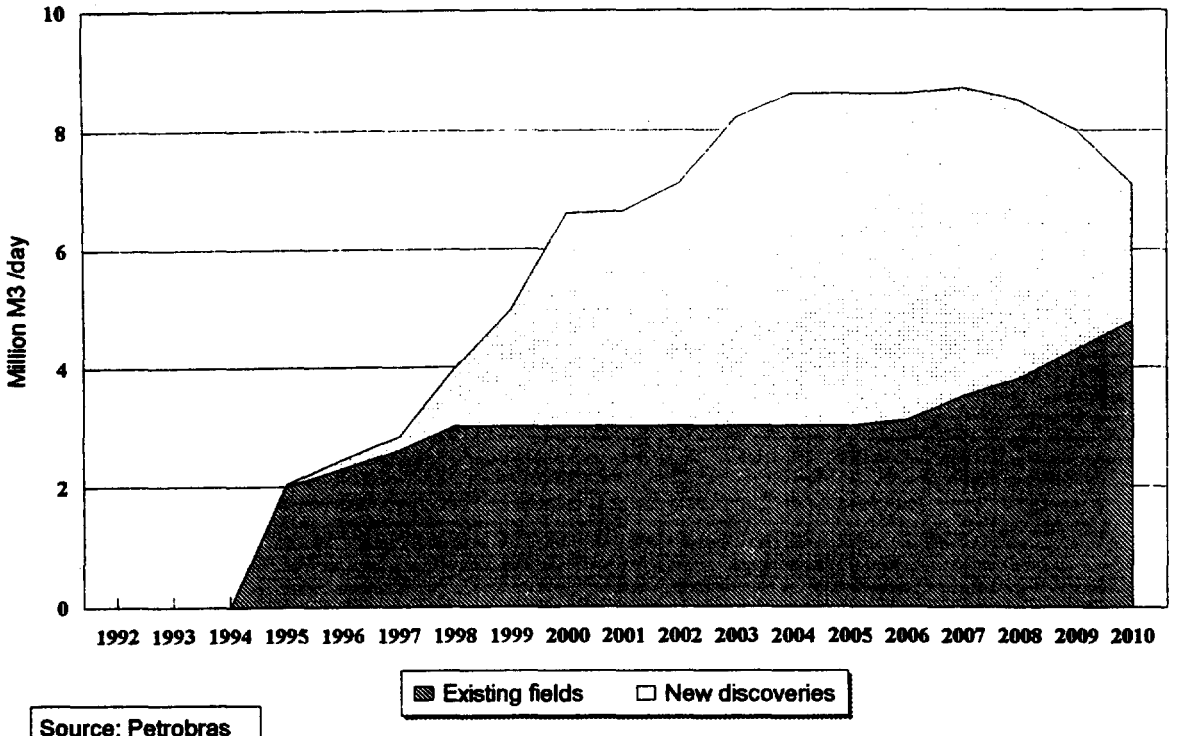


Fig.5

Amazonas - Gas available for sale

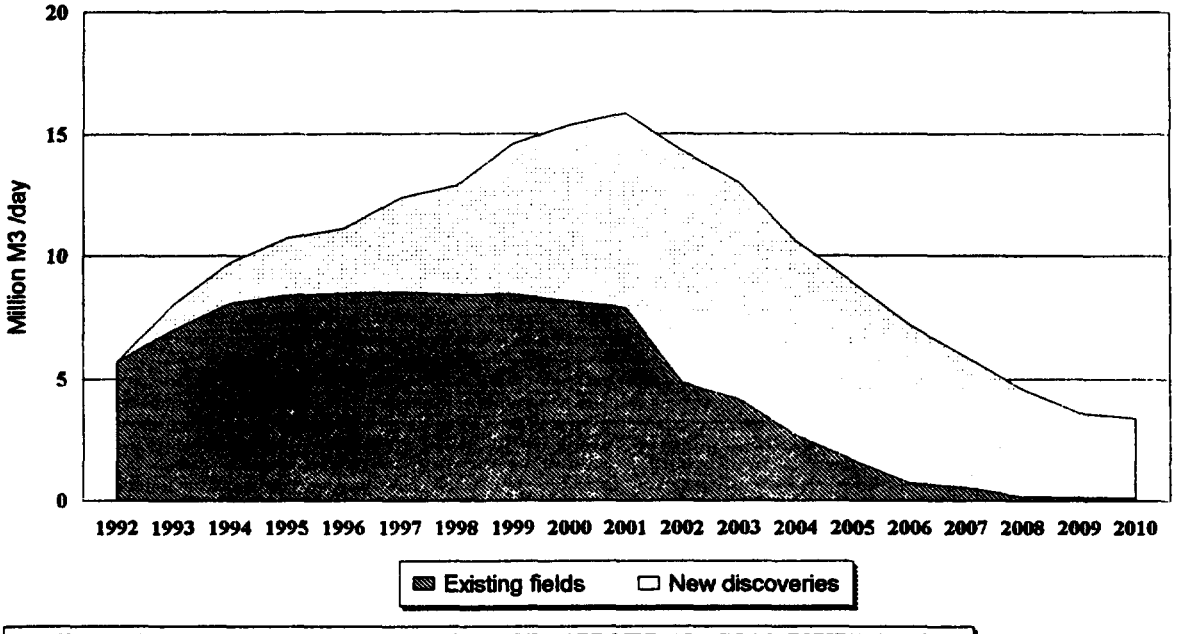
PETROBRAS PROJECTIONS



Source: Petrobras

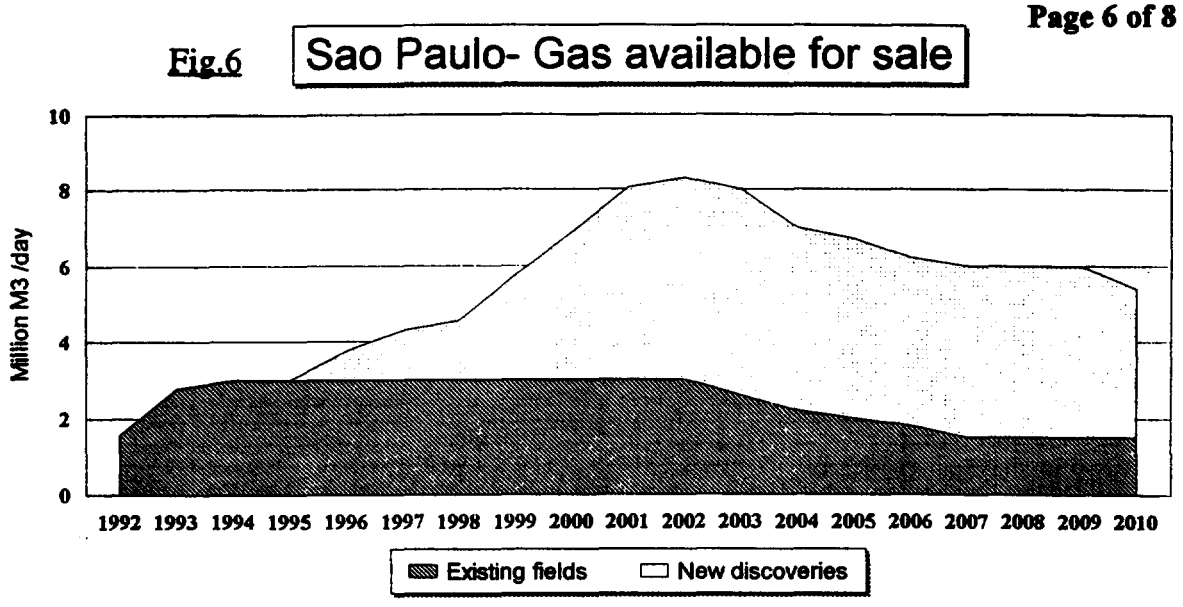
North East Brazil - Gas available for sale

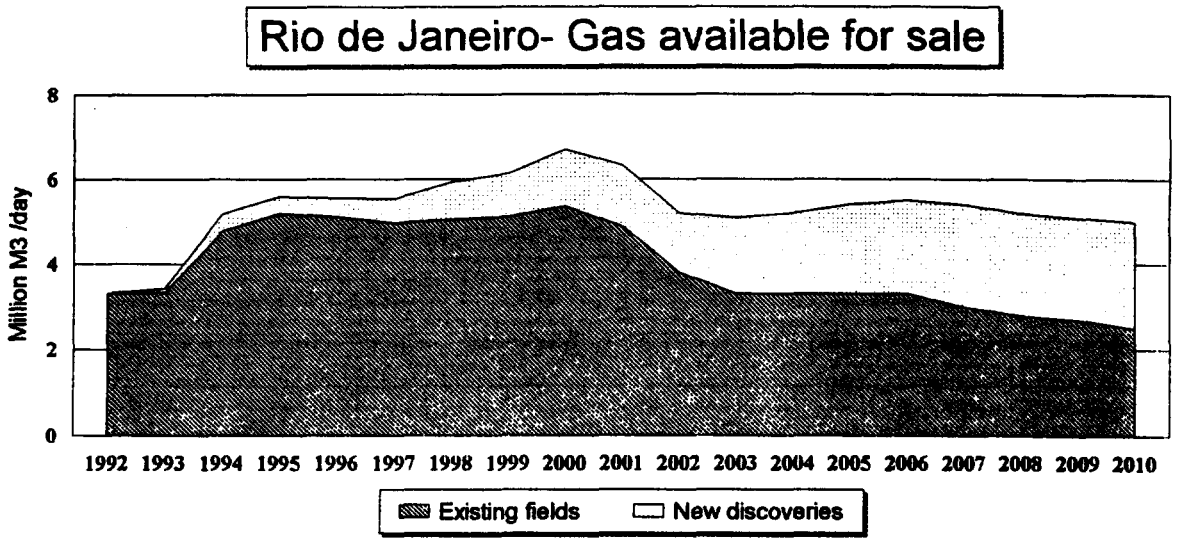
PETROBRAS PROJECTIONS



STATES OF CEARA,RIO GRANDE DO NORTE, BAHIA, SERGIPE, ALAGOAS, ESPIRITO SANTO

Fig.6


Sao Paulo- Gas available for sale
Million M3 /day
0
2
4
6
8
10
1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010
Existing fields
New discoveries


Rio de Janeiro- Gas available for sale
Million M3 /day
0
2
4
6
8
1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010
Existing fields
New discoveries

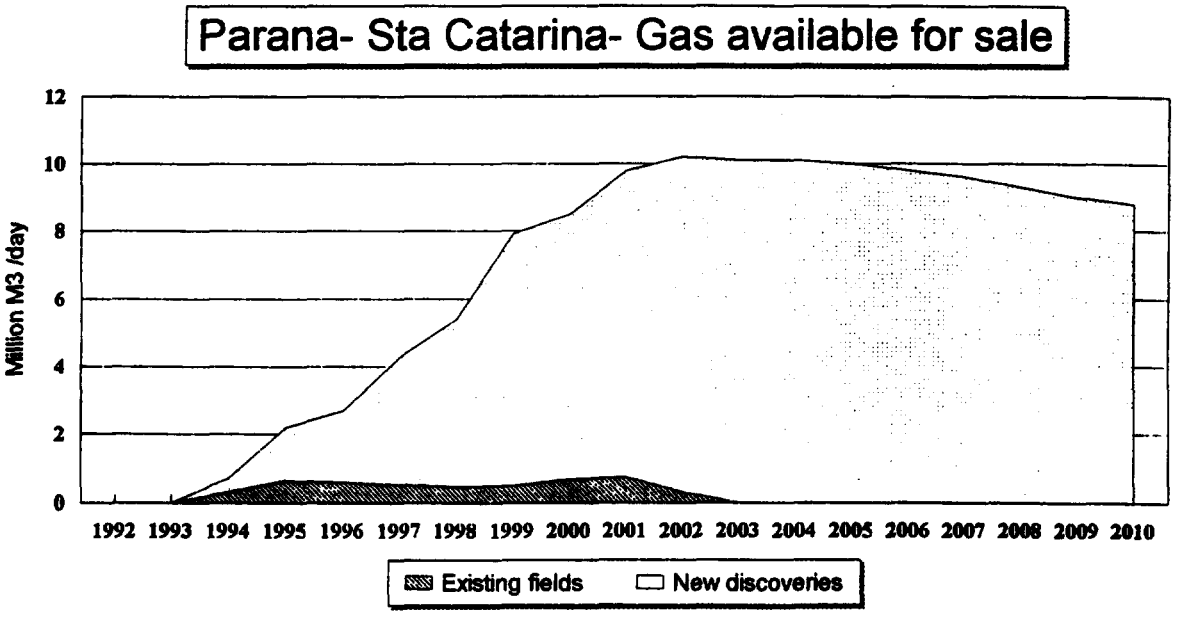
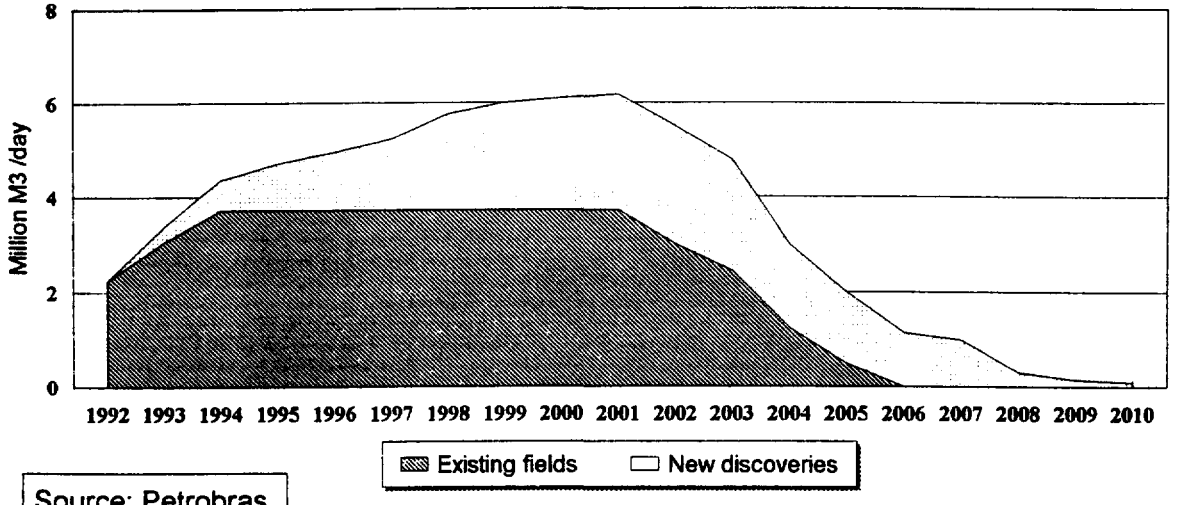
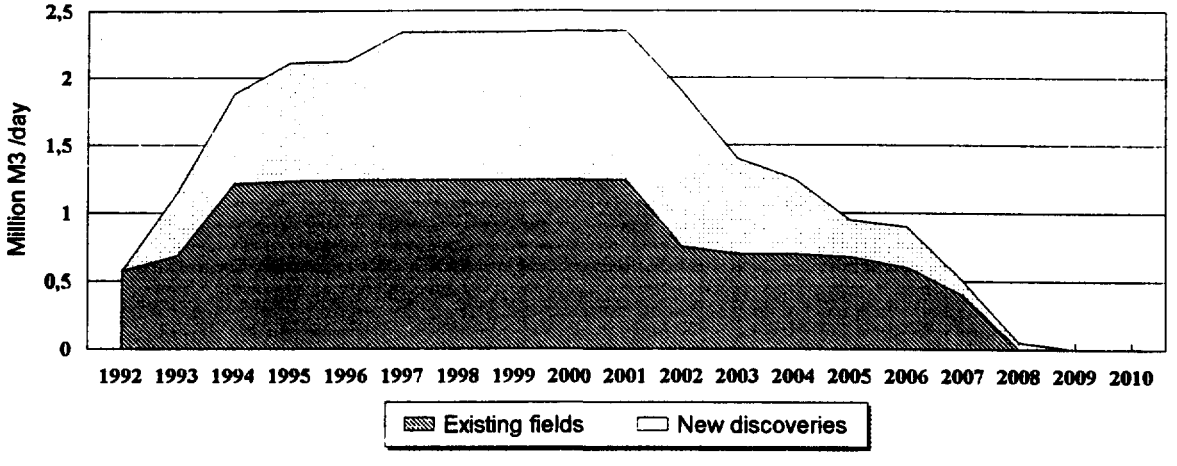

Parana- Sta Catarina- Gas available for sale
Million M3 /day
0
2
4
6
8
10
12
1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010
Existing fields
New discoveries

Fig.7 Bahia - Gas available for sale



Source: Petrobras

Alagoas - Gas available for sale



Sergipe - Gas available for sale

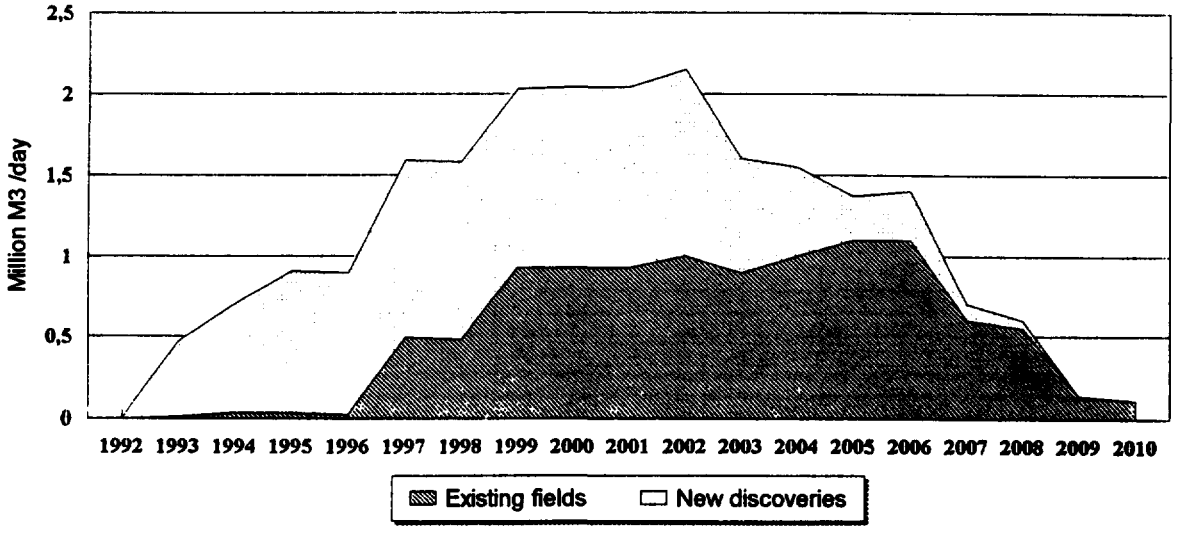
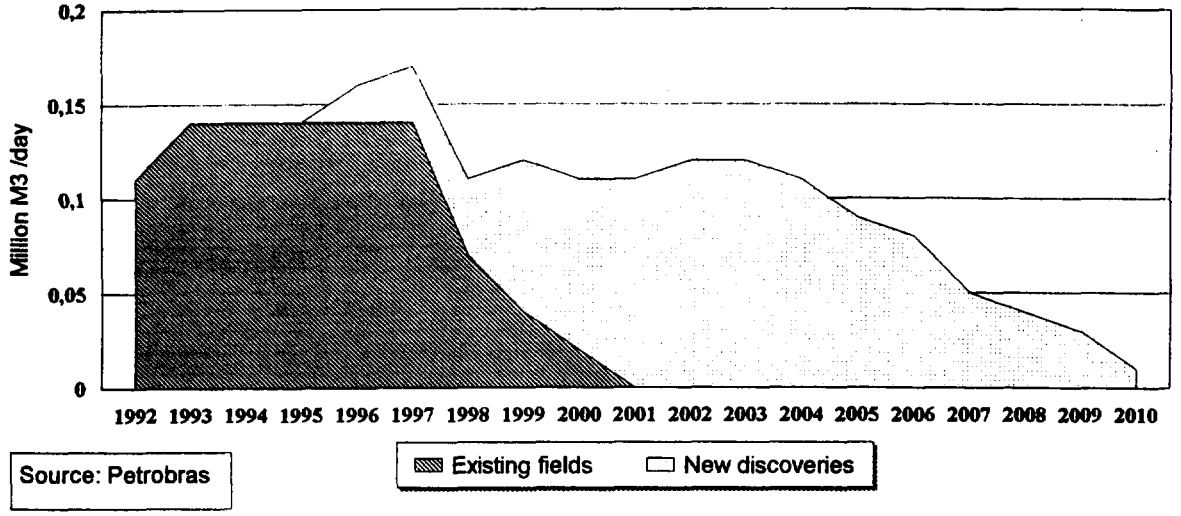


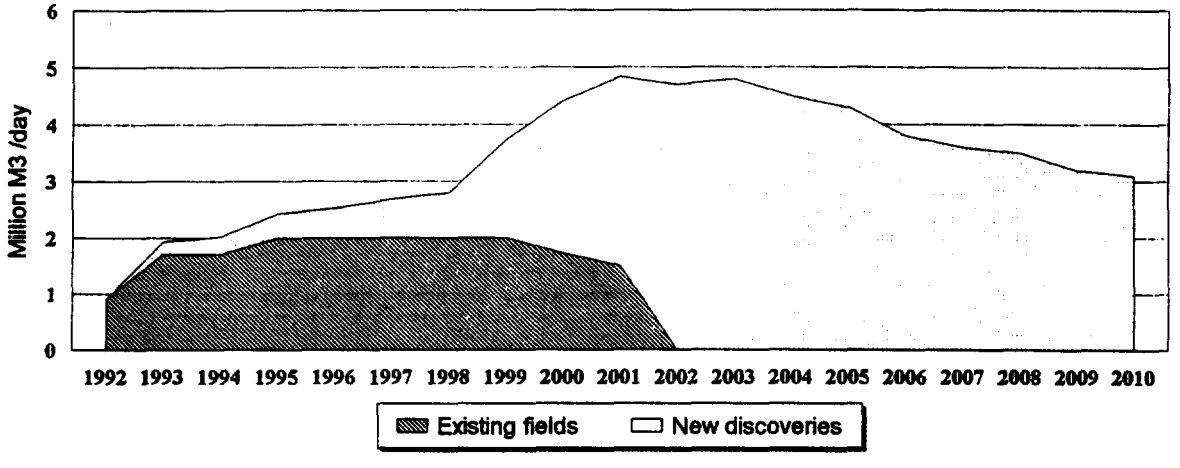
Fig.8

Ceara - Gas available for sale

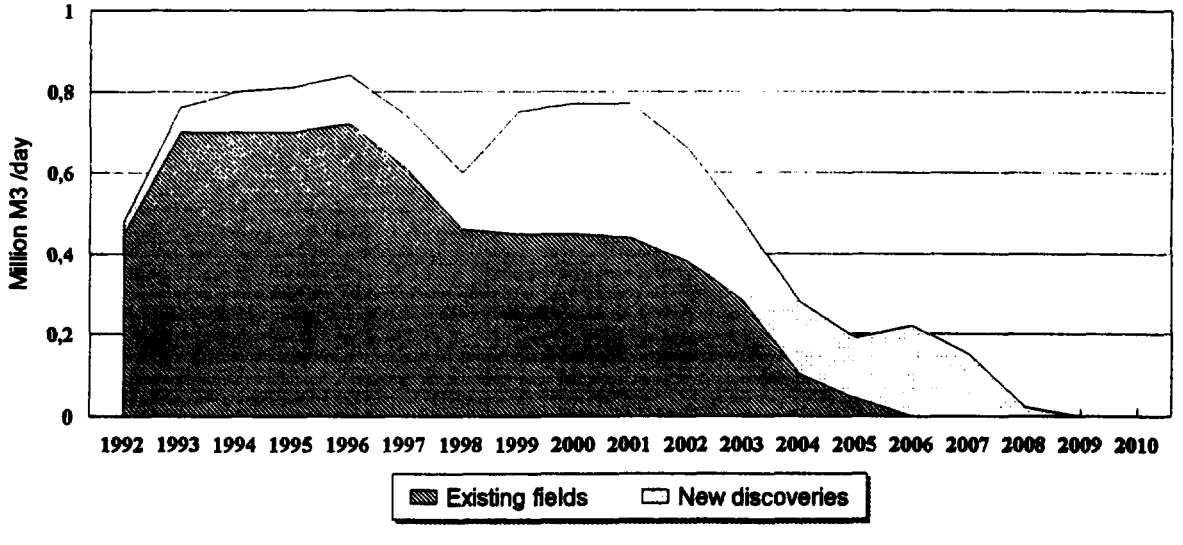


Source: Petrobras

Rio Gde Do Norte - Gas available for sale



Espirito Santo - Gas available for sale



ANNEX 2.2

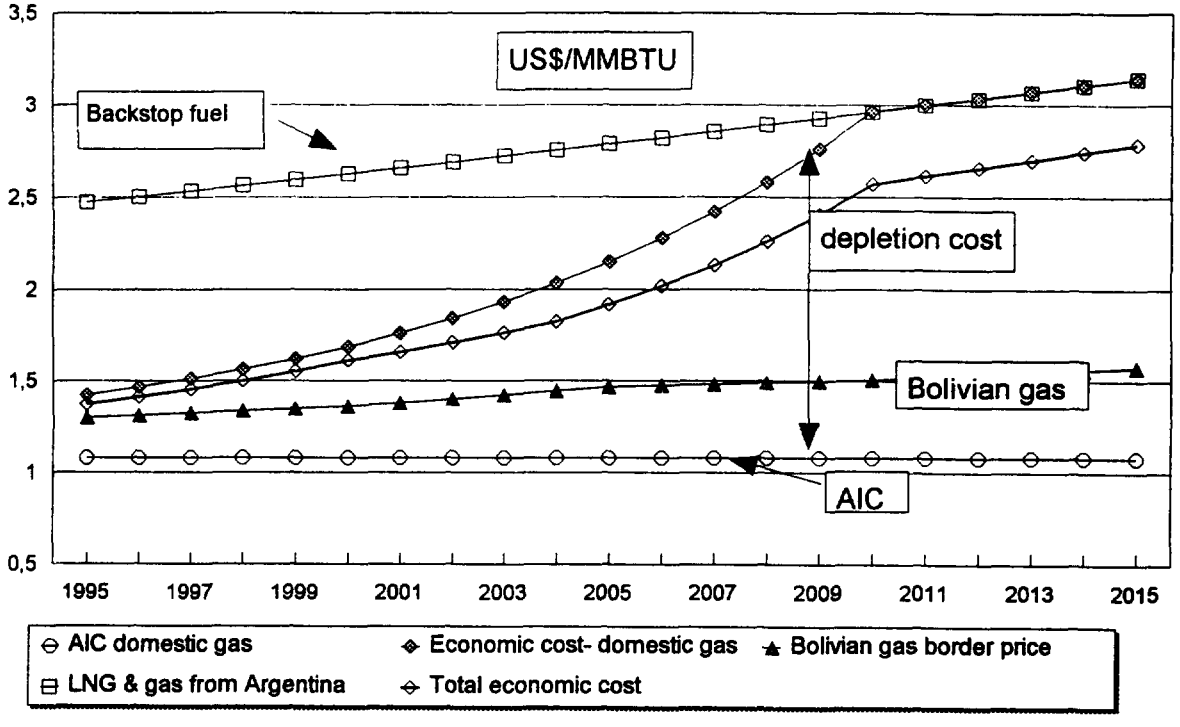
ECONOMIC COST OF GAS IN SOUTH,SOUTH EAST BRAZIL

Fig.1 The Economic Cost of Gas in South - South East Brazil

FIG 1

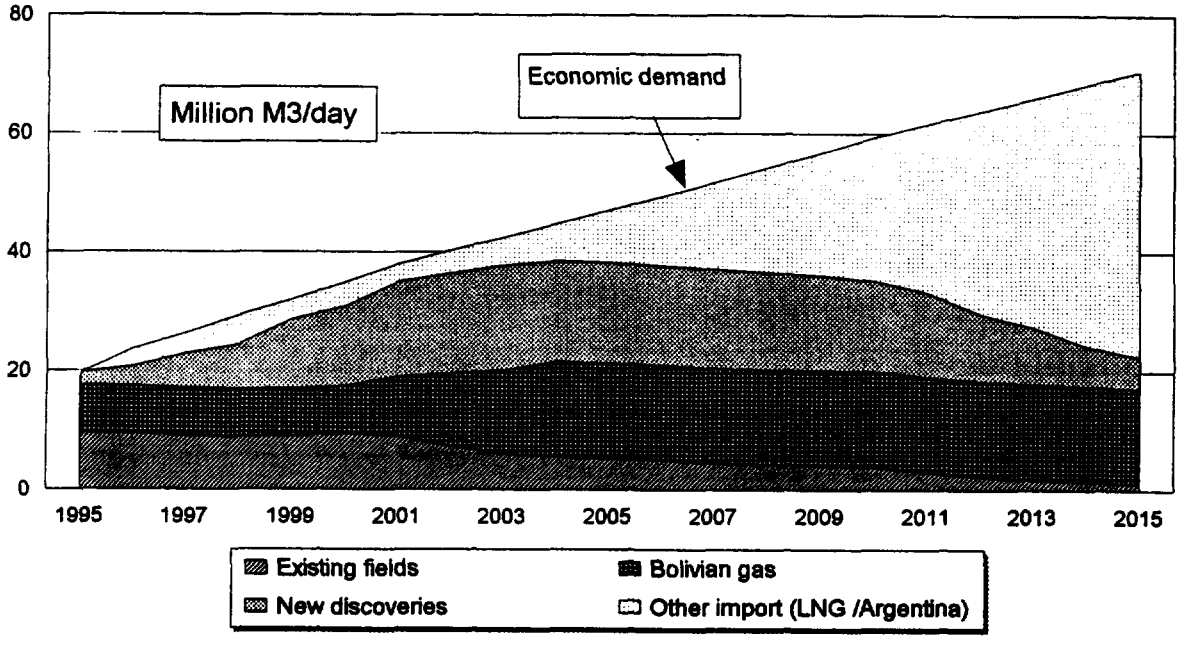
Economic cost of gas in South South East Brazil

Based on average economic demand



Gas supply in South South East Brazil

Following average economic demand



Source: PETROBRAS and 1993 Gas Sector Mission Estimates

ANNEX 2.3

EXISTING REFINERY CAPACITY AND STRUCTURE

ANNEX 2.3
Page 1 of 2

Table 1: Existing Refinery Capacity of Brazil

	Refinery	Nominal Capacity cm/day
REPLAN	Paulinia (SP)	48 000
REDUC	Duque de Caxias (Rio)	38 000
REVAP	Henrique Lace (SP)	34 000
REGAP	Gabriel Passos (MG)	24 000
REPAR	Getulio Vargas (PA)	27 000
RPBC	Presid. Bernardes (SP)	27 000
RLAM	Landolpho Alves (BA)	19 350
REFAP	Alberto Pasqualini (RS)	30 000
RECAP	Capuava ((SP)	8,508
REMAN	Manaus (AM)	1 800
ASFOR	Fab. Asfalto Fortaleza	900
Total		256 550

Source : Petrobras -1996

Table 2: Existing Refinery Structure

	Nominal Capacity (mcm/d)	Cat.Crack. Capacity (mcm/d)	Coking Capacity (mcm/d)	Deasphalt. Capacity (mcm/d)	Hydrotreat. Capacity (mcm/d)[1]
REPLAN	48 000	16 000	-	-	-
REDUC	38 000	7 500	-	6,600	2 100 D 2 800 J
REVAP	34 000	10 500	-	-	3 200 N 6 500 D 4 300 J
REGAP	24 000	6 000	3 250	-	1 800 N 4 200 D 1 800 J
REPAR	27 000	8 300	-	5 500	-
RPBC	27 000	9 500	5,200	-	-
RLAM	19 350	4 600	-	570	-
REFAP	30 000	4 600	-	-	-
RECAP	6 500	1 800	-	-	-
REMAN	1 800	500	-	-	-
ASFOR	900	-	-	-	-
TOTAL (mcm/d)	256 550	67 300	8 450	18 670	5 000 N 12 800 D 8,900 J

Source : Petrobras - 1996
(1) N = Naphtha, D = Diesel oil, J = Jet fuel

ANNEX 2.3

Table 3 Refinery Upgrading Program to 2000

REFINERY	Atm/Vac.DistCapacity (cm/d)	Cat.Crack. Capacity (cm/d)	Coking Capacity (cm/d)	Deasphalt. Capacity (cm/d)	Hydrotreat. Capacity (cm/d)
REPLAN	6000(1999), 6000(2000)	-	5000(1997)	-	5000(1997)
REDUC	8 000(1997)	2500(1997)[1]	2500(1999)		5000(1999)
REVAP	-	-	-	-	-
REGAP	-	-	3200(1993)	-	-
REPAR	-	-	-	-	5000(1998)
RPBC	5000(1998)	2000(1998)[1]	-	-	5000(1997)
RLAM	27000(1996)[1]	6000(1999)	-	5000(1999)	-
REFAP	18000(1999)1	3000(1999)	-	-	4000(1998)
RECAP	-	-	-	-	-
REMAN	-	-	-	-	-
TOTAL					
(cm/d)		13500	10700	5000	24000
(Mt/y)		4.00	3.35	1.57	6.33

Source : Petrobras Gas Sector Mission - 1993
1 - Revamp.

ANNEX 2.4

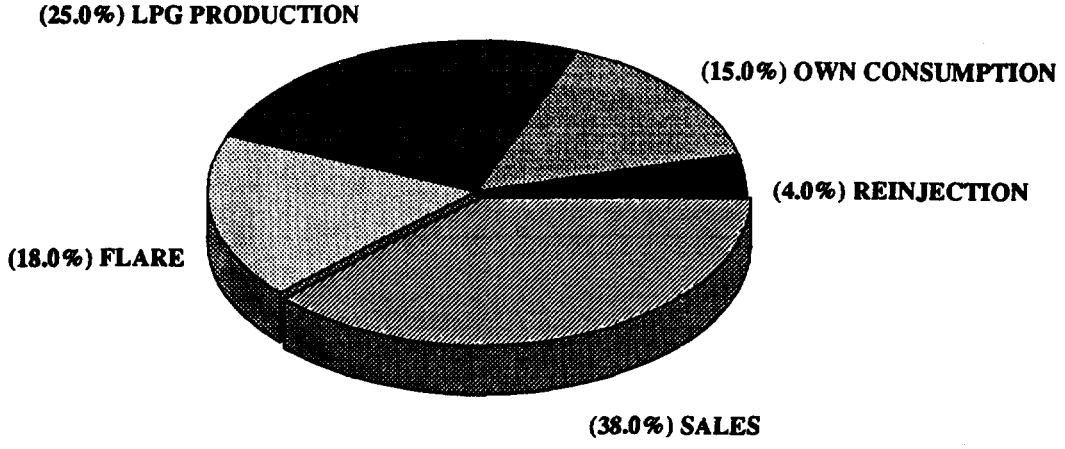
NATURAL GAS DEMAND AND UTILISATION IN BRAZIL

Fig 1 Gas Utilisation and Allocation of Sales in 1995

Fig. 1

Gas utilization in Brazil in 1995

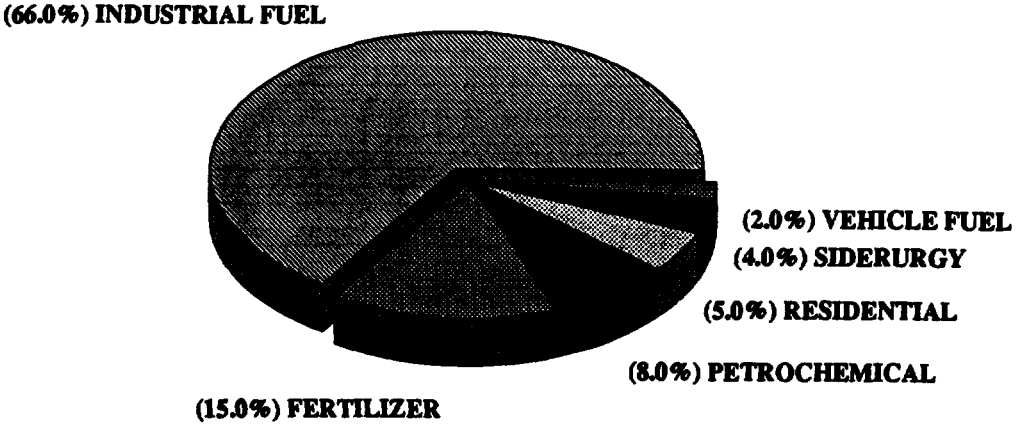
1000 M3 / day



TOTAL: 21,884 (1000 M3/day)
Source : Petrobras

Allocation of gas sales in 1995

1000 M3 / day



TOTAL: 8 618 (1000 M3/day)
Source : Petrobras

ANNEX 3.1

ENERGY PRICE TRENDS

Fig.1 Typical Energy Prices for Residential and Transport Sectors, June 1993 - December 1995

Fig.2 Typical Energy Prices for the Industrial Sectors, June 1993 - December 1995

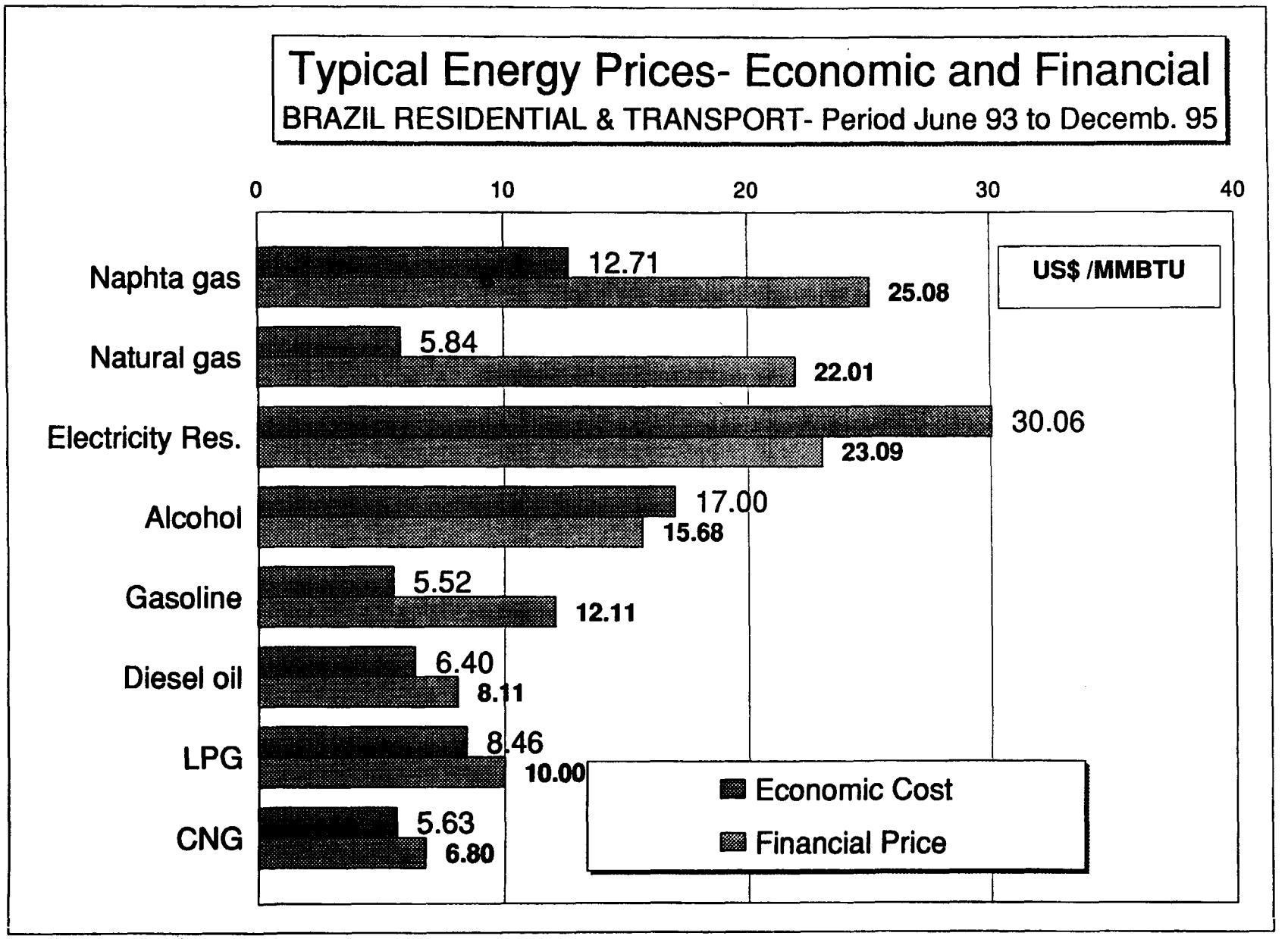
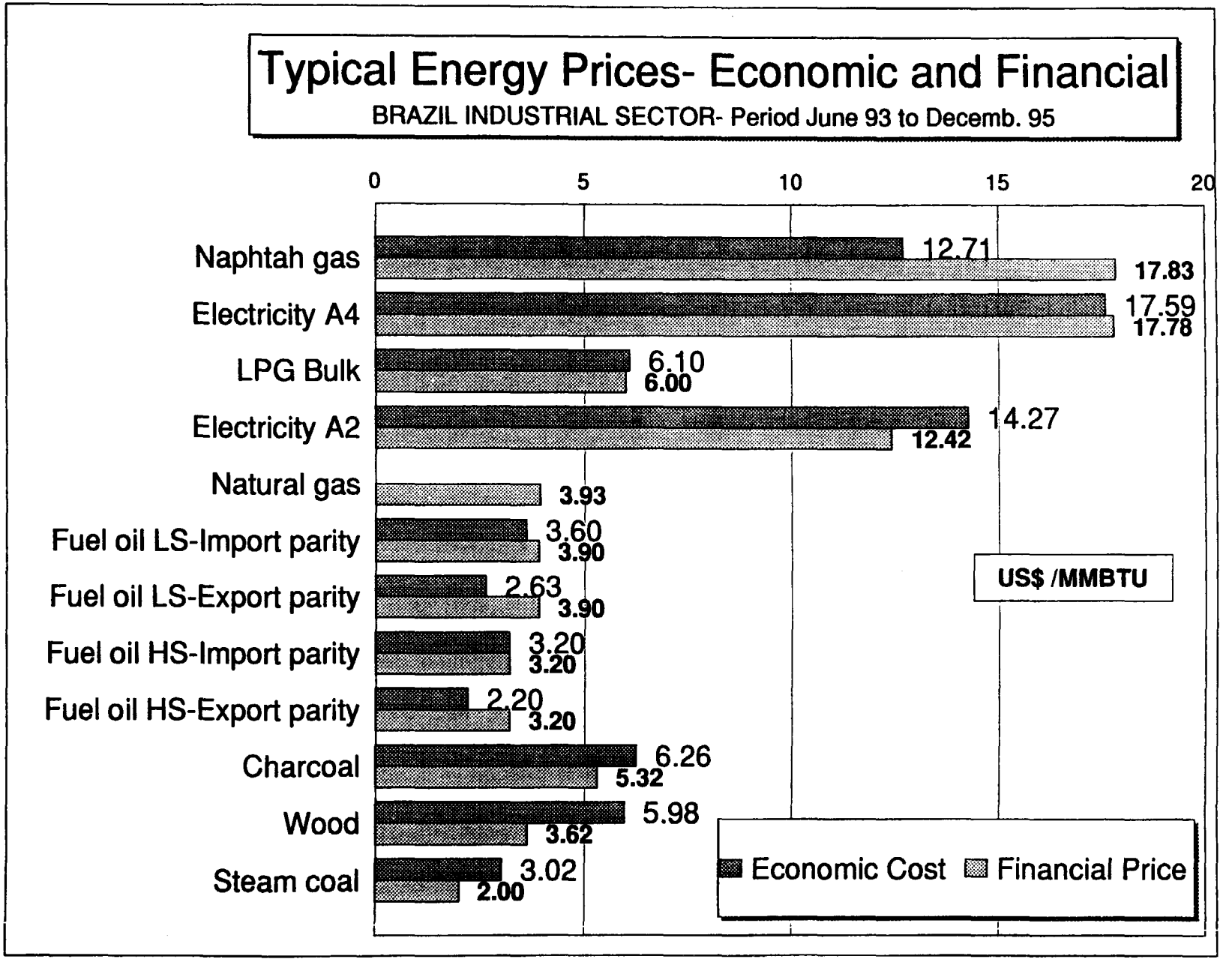

Typical Energy Prices- Economic and Financial
BRAZIL RESIDENTIAL & TRANSPORT- Period June 93 to Decemb. 95
0
10
20
30
40
US$ /MMBTU
Naphta gas
12.71
25.08
Natural gas
5.84
22.01
Electricity Res.
30.06
23.09
Alcohol
17.00
15.68
Gasoline
5.52
12.11
Diesel oil
6.40
8.11
LPG
8.46
10.00
CNG
5.63
6.80
Economic Cost
Financial Price

Fig. 2


Typical Energy Prices- Economic and Financial
BRAZIL INDUSTRIAL SECTOR- Period June 93 to Decemb. 95
0
5
10
15
20
Naphtah gas
12.71
17.83
Electricity A4
17.59
17.78
LPG Bulk
6.10
6.00
Electricity A2
14.27
12.42
Natural gas
3.93
Fuel oil LS-Import parity
3.60
3.90
Fuel oil LS-Export parity
2.63
3.90
Fuel oil HS-Import parity
3.20
3.20
Fuel oil HS-Export parity
2.20
3.20
Charcoal
6.26
5.32
Wood
5.98
3.62
Steam coal
3.02
2.00
US$ /MMBTU
Economic Cost
Financial Price

ANNEX 3.2

ILLUSTRATION OF GAS TARIFFICATION PRINCIPLES

GAS TARIFICATION SYSTEM

FIG 1

ANNEX 3.2
Page 1 of 4

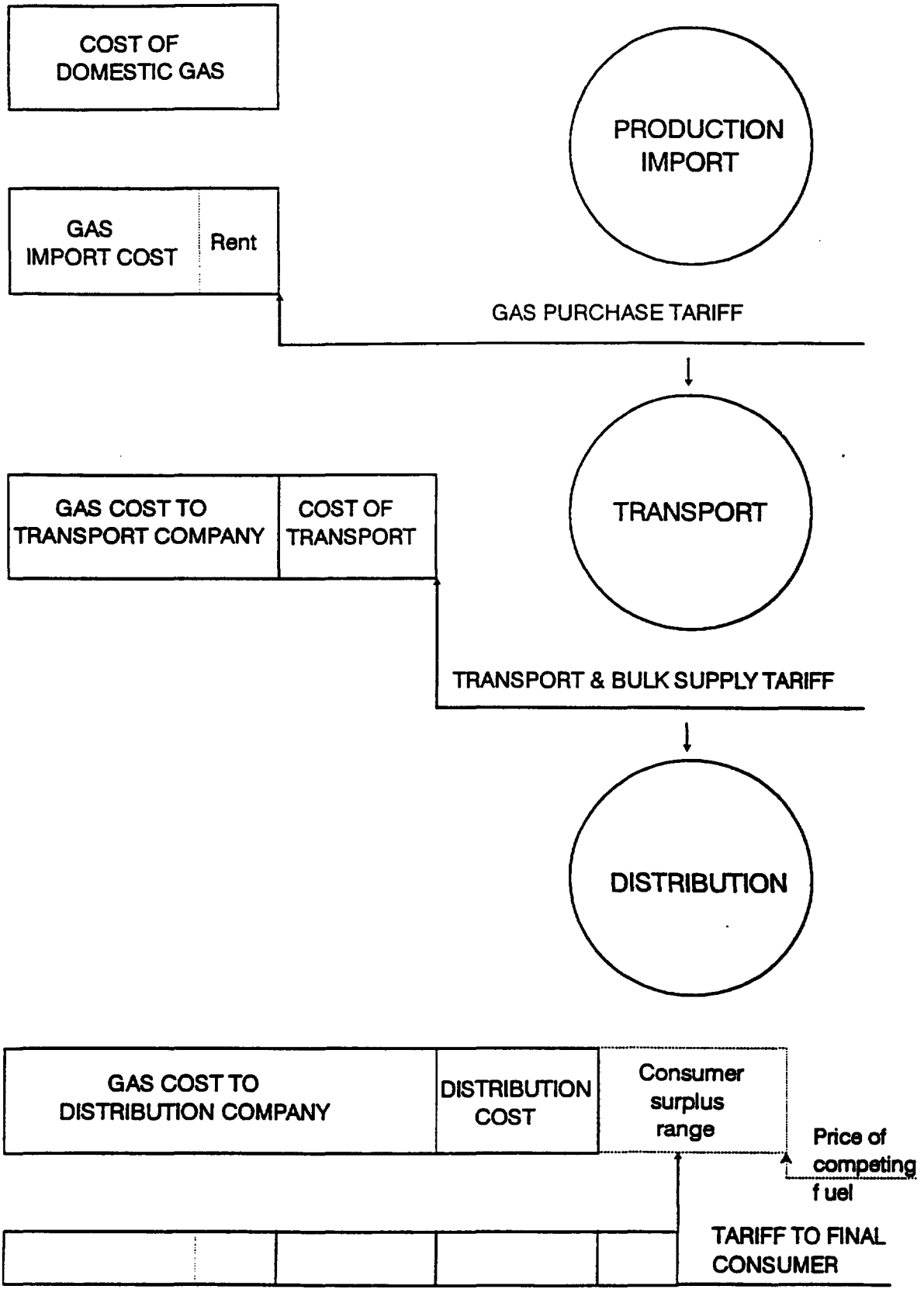


FIG 2

PIPELINE TRANSPORT TARIFF - METHODOLOGY

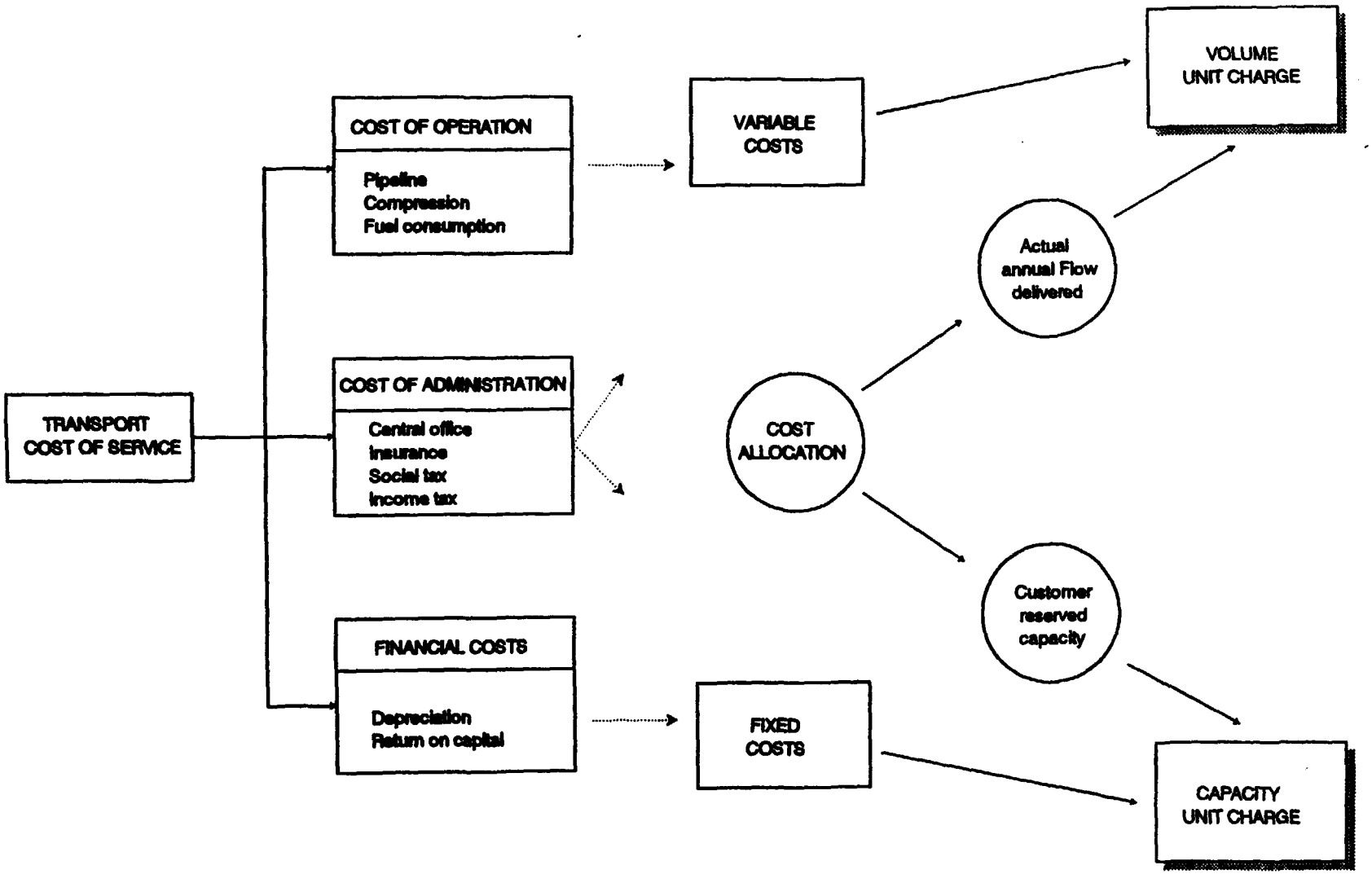
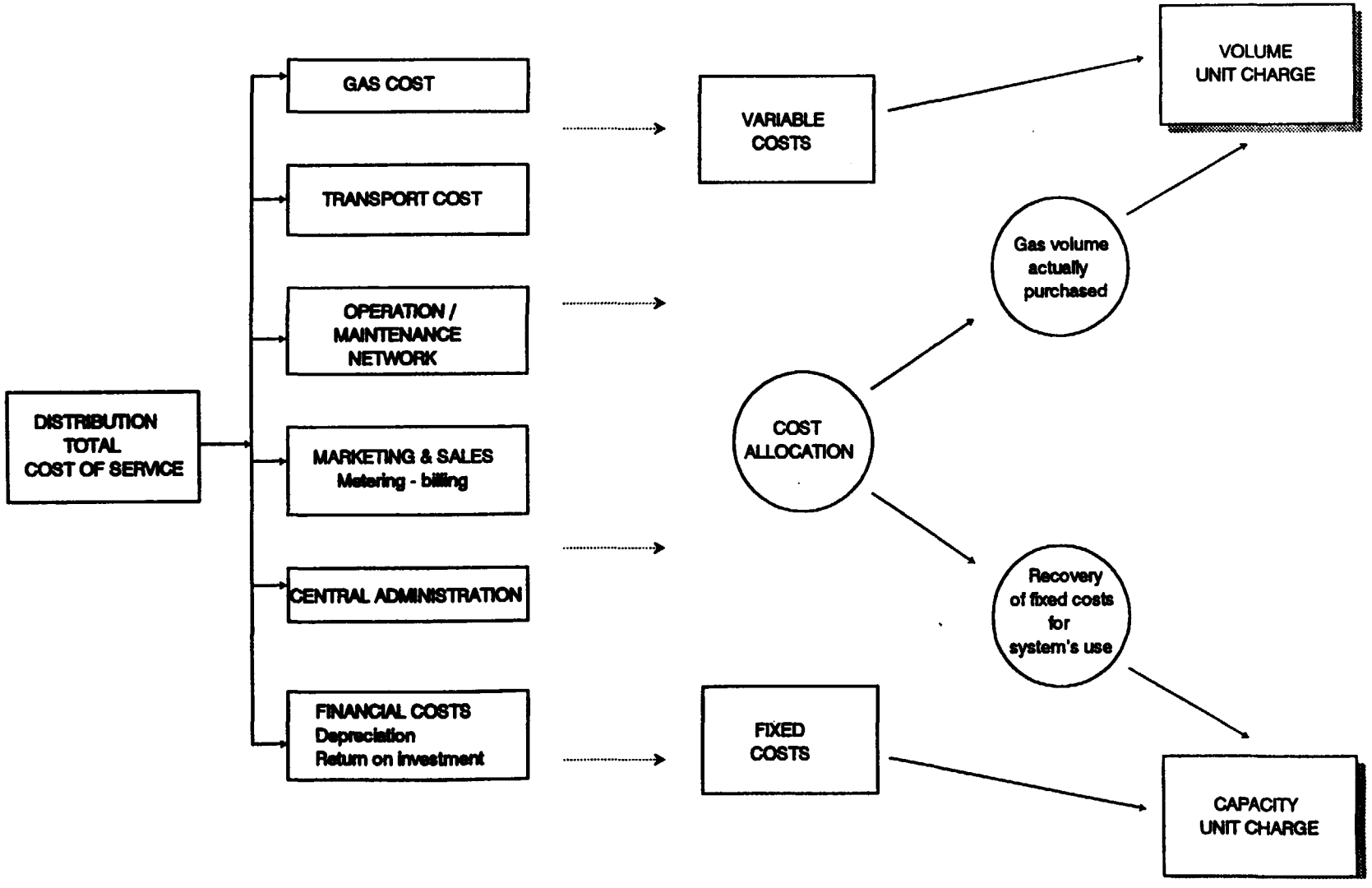


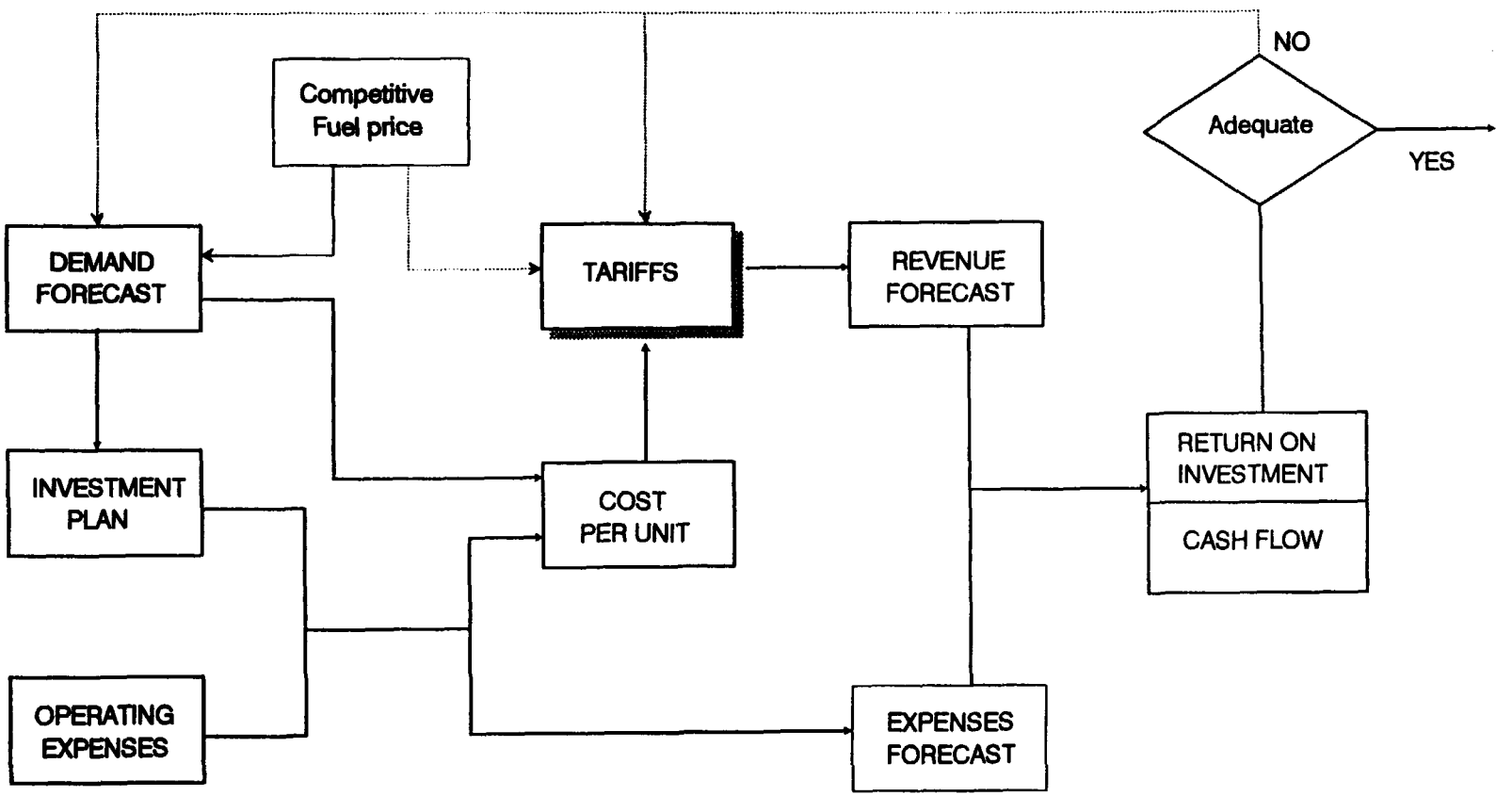
FIG 3

GAS TARIFF AT RETAIL LEVEL - METHODOLOGY



TARIFF SETTING LOOP IN A LONG TERM PLANNING PERSPECTIVE

FIG 4



GAS TARIFFICATION IN EUROPEAN COUNTRIES

1. PARAMETERS OF GAS TARIFICATION

Whatever type of formula is applied to gas tarification for industrial or residential consumers, a certain number of parameters have to be considered, related to characteristics of consumption for different categories of users.

Annual volume consumed : QA -

It reflects the total annual volume of gas consumed, expressed in Gigajoules (GJ), cubic meters (M3), or million cubic feet (MMCF)

Daily load factor : ND -

Apart from the annual quantity consumed, the nature of industrial uses leads to consider the regularity with which the user takes gas from the network. This is reflected by the concept of **modulation** or **load factor**.

The daily load factor (ND) is the **number of days** which would be required to take the entire annual consumption at the maximum daily offtake rate :

ND = QA / QD. MAX
with QD.MAX : maximum daily offtake.

Hourly load factor : NH -

It also reflects the regularity of gas offtake, and is defined as the number of hours which would be required to take the entire annual consumption at the maximum hourly offtake rate.

NH = QA / QH.MAX
with QH.MAX : maximum hourly offtake.

The 2 above parameters determine the peaks or offtake ceilings reached by the consumer in the course of one day or one hour over the year.

As an example, in the case of a user who consumes 40 MMCF/year, a load factor of 200 days means that the maximum daily offtake is 0.20 MMCF, and a load factor of 1600 hours means that the maximum hourly offtake is 25 000 cu.ft or 700 M3/hour.

Regularity factor : RH -

This is another way to express the regularity of gas offtake, by the ratio of hourly load factor to the total number of hours in a year (8760 h.)

RH = NH/8760 = QA/(8760 * QH.MAX)

A high value of RH means a regular gas offtake, that is an evenly distributed load all over the year.

Interruptibility factor : CNE -

In some cases, industrial consumers negotiate interruptible contracts, under which the seller of gas can reduce the quantities supplied to the consumer at certain peak times when the network is overloaded. In return for this constraint of interruption of supply, the consumer pays a reduced price.

The interruptibility factor varies between 0 and 1, and reflects the level of "non interruptibility" of the gas supply :

CNE = 1 means a non interruptible supply
CNE = 0 means a fully interruptible supply

The interruptibility factor can be expressed by the ratio of firm consumption (non interruptible) to total annual consumption :

CNE = QAF/QA
with QAF : firm expected consumption.

Coefficient of utilization : P -

This coefficient is sometimes used to introduce a price differentiation between different types of gas utilization, such as :

- non specific application : substitution for fuel oil in common heating process

- specific application : substitution for high value fuels (diesel oil, LPG) in specific processes.

- use as feedstock : petrochemistry

Classification of industrial consumers

Prior to the establishment of precise tarification formulas, it is useful to analyse several categories of standard gas consumers with their own characteristics in particular annual consumption and modulation.

Five categories of standard industrial consumers have been presented in Table 1, chosen as being representative of the normal population of industrial gas consumers (this classification is used for statistical surveys in European Countries).

It appears that certain standard consumers have the same load factor for different volumes of consumption or, conversely, different load factors for the same volume of consumption ; this clearly enables to adapt the level of prices to the conditions of supply for each category of consumer. The higher the load factor (in days or hours) the more regular the offtake of gas, thus enabling to charge more favourable prices.

Moreover, the load factor gives some indication of the use made by installations consuming gas: a very high load factor, e.g. of 8000 hours, is clearly equivalent of an installation functioning practically non stop, day and night, throughout the 8760 hours in the year.

Characteristics of standart industrial consumers (1)

TARIFF	Annual Consommation		Daily Modulation		Hourly Modulation	
	M³/Y	GJ/y	Nb. of days	Max Flow MMCFD	Nb. of hours	Max Flow M³/H
I1 (2)	11,000	418.6	115 200			
I2 (2)	110,000	4186	200	0.02		
I3 - 1 I3 - 2	1.1 M	41,860	200 250	0.20 0.16	1,600 4,000	700 280
I4 - 1 I4 - 2	11 M.	418,600	250 300	1.6 1.2	4,000 8,000	2,800 1,400
I5	110 M.	4.18 M	330	12.	8,000	14,000

(1) Standard consumers characteristics are chosen as being representative of the population of industrial gas consumers. The above classification is used for statistical surveys in European countries.

(2) Type consumers I1 and I2 also cover commercial, public administration, large residential customers.

2. TARIFICATION FORMULAE

Despite a wide variety of approaches to tarification in gas consuming countries (we refer in particular to European Countries), historical developments have favoured the elaboration of binomial formulae rather than single term or polynomial formulae :

A typical binomial formula involves :

. a fixed term
. a proportional price (per unit of gas consumed)
. a mechanism for indexation

Fixed term

The fixed term has generally to cover the subscription and meter rental, and to reflect the particular conditions of supply (volume and regularity) of each category of consumer.

It is paid monthly, or most often annually, and may have the following structure :

TFo * (1 - RH) * QH.MAX * K * INDEX

with :

TFo	:	base reference value
RH	:	regularity factor
QH.MAX	:	maximum hourly offtake
K	:	sliding scale coefficient
INDEX	:	indexation factors

It can be seen that this fixed term:

. is proportional to the maximum hourly offtake (to penalise peak consumption)

. decreases when the regularity of offtake is higher (RH)

. provides a lower price for larger volumes of consumption (sliding scale tariff through the K coefficient).

Proportional price

The proportional term has to take account of several factors, in particular the acquisition cost of gas (GC), the type of utilization (P), a sliding scale effect (K), and interruptibility constraints (CNE).

The most comprehensive formulation would thus be as follows:

$$(Ao * GC) + (Bo + CNE) * P * K * INDEX$$

with:

Ao, Bo	:	base values
GC	:	acquisition cost of gas
CNE	:	interruptibility factor
P	:	coefficient of utilization
K	:	sliding scale factor
INDEX	:	indexation factors

Particular cases

- In case of **interruptible contracts**, RH =1 and CNE = 0, so that the fixed term is null and the proportional term becomes:

  $$Ao * GC + Bo * P * K * INDEX$$

  which is equivalent to a binomial formula with a fixed term indexed on gas acquisition cost.

- If gas acquisition cost is not taken into account, the proportional term becomes :

  $$(Bo + CNE) * P * K * INDEX$$

Indexation

The fixed term and the proportional price of a binomial formula are generally indexed with the same index or with different indexes.

The indexation mechanism aims at **protecting both parties, the seller and the consumer**, against changes in gas supply conditions (for the seller) and in competitive fuel environment (for the buyer). In particular, when most gas consumers have a **dual fuel capability**, speed of response of the index to changes in market conditions is of prime importance.

Indexation systems are quite variable according to the country and the conditions of gas supply, but one or several of the following indexes are generally considered:

. price of competing fuels: essentially fuel oil (sometimes a weighted average of 2 qualities of fuel oil, low and high sulphur). Indexation with competitive fuels is clearly a necessity for interruptible contracts.

. cost of gas acquisition

. index of inflation or of salaries

Most often, the fixed term is indexed with inflation or salaries, while the proportional price is indexed with competitive fuels or cost of gas acquisition.

3. GAS TARIFFS IN SELECTED EUROPEAN COUNTRIES

A review has been made of actual gas tariffs in six European countries : UK, Netherlands, Italy, France, Belgium, Germany.

For each country, a summary sheet presents the institutional organization of the gas sector, followed by a detailed description of tarification formulas used in each sector.

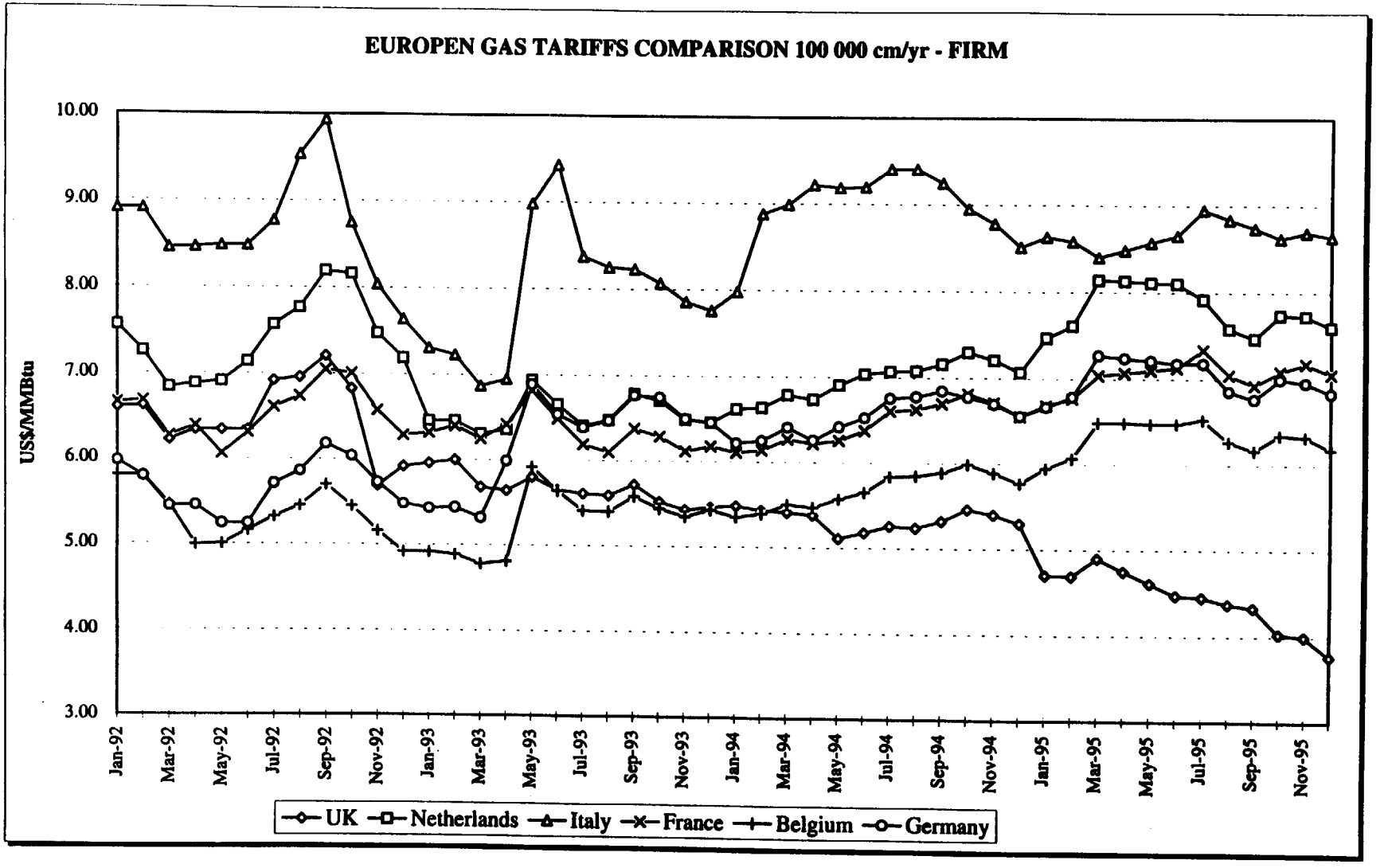
The comparison of European gas tariffs is illustrated by a series of graphs showing the evolution over 1991 and 1992 of industrial tariffs for the following classes of consumption :

. 100 000 M3/year firm
. 1 million M3/year firm
. 50 million M3/year firm
. 50 million M3/year interruptible

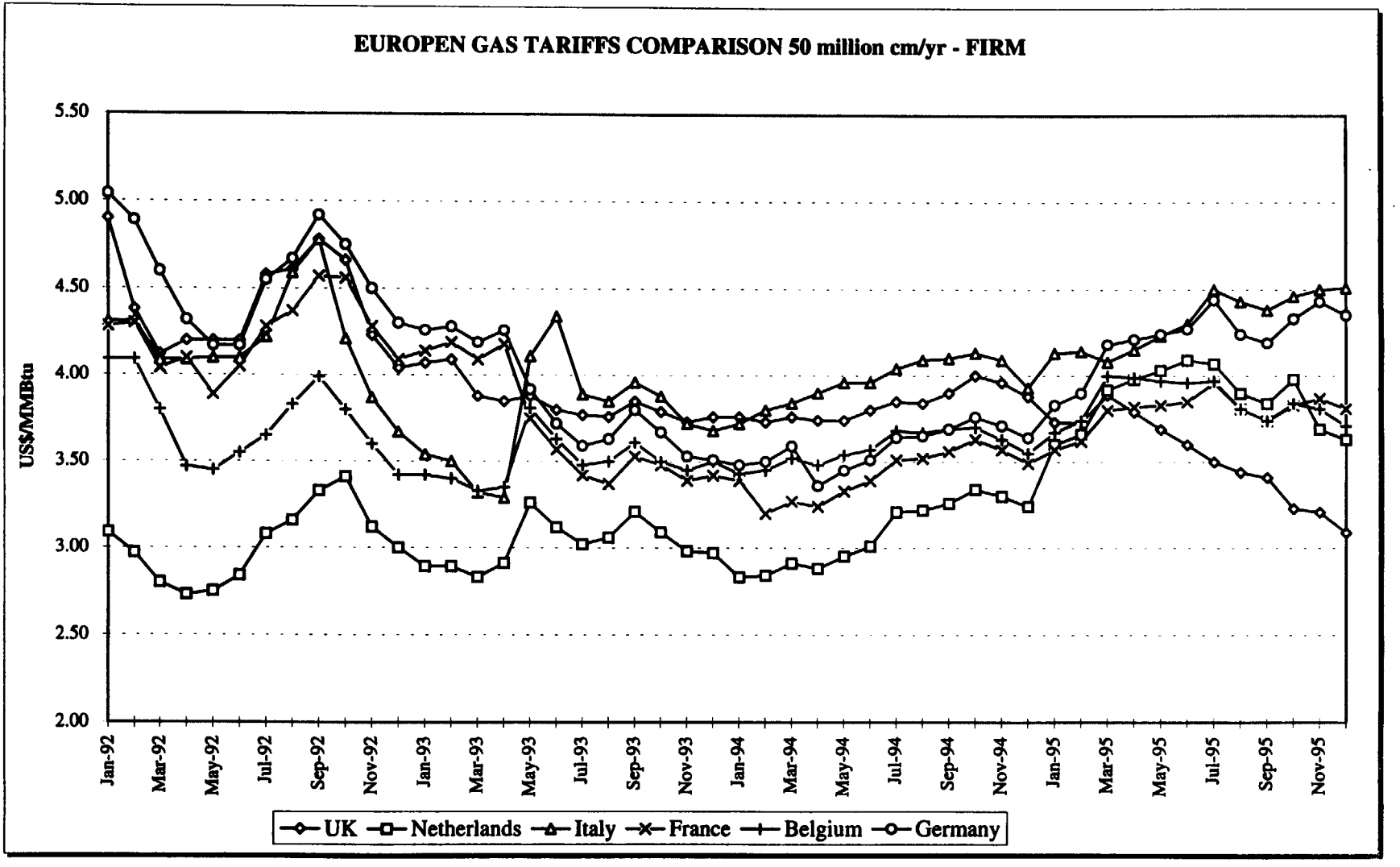
The FOB prices of main competing fuels, fuel oil and diesel oil have also been plotted.

It appears that gas prices may vary substantially from one country to another, resulting from many factors, but essentially the cost of gas supply to the country and the policy of distribution companies.

100000

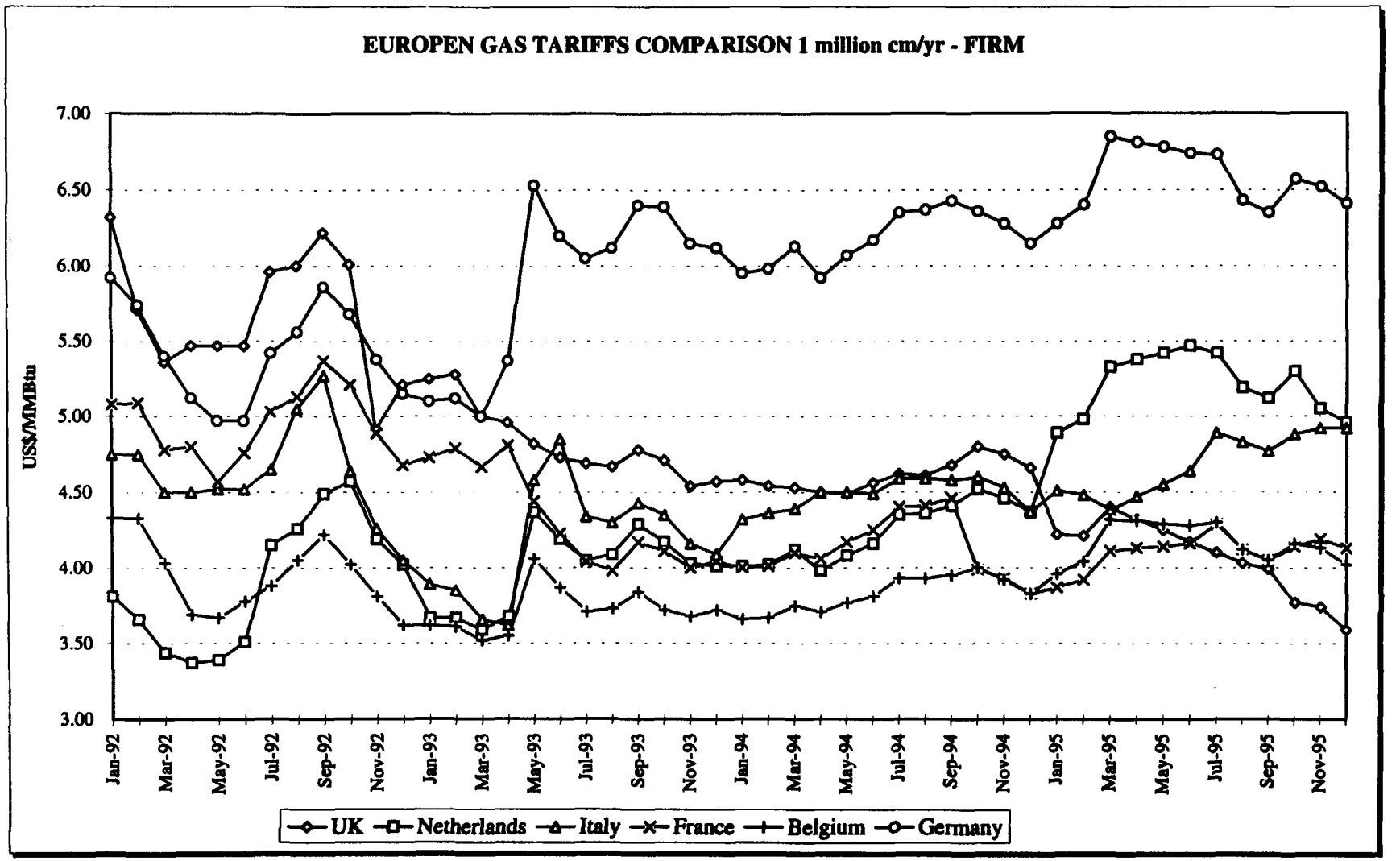

EUROPEN GAS TARIFFS COMPARISON 100 000 cm/yr - FIRM
US$/MMBtu
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
UK
Netherlands
Italy
France
Belgium
Germany

50 million firm



Page 1

1million


EUROPEN GAS TARIFFS COMPARISON 1 million cm/yr - FIRM
US$/MMBtu
7.00
6.50
6.00
5.50
5.00
4.50
4.00
3.50
3.00
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
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Sep-95
Nov-95
UK
Netherlands
Italy
France
Belgium
Germany

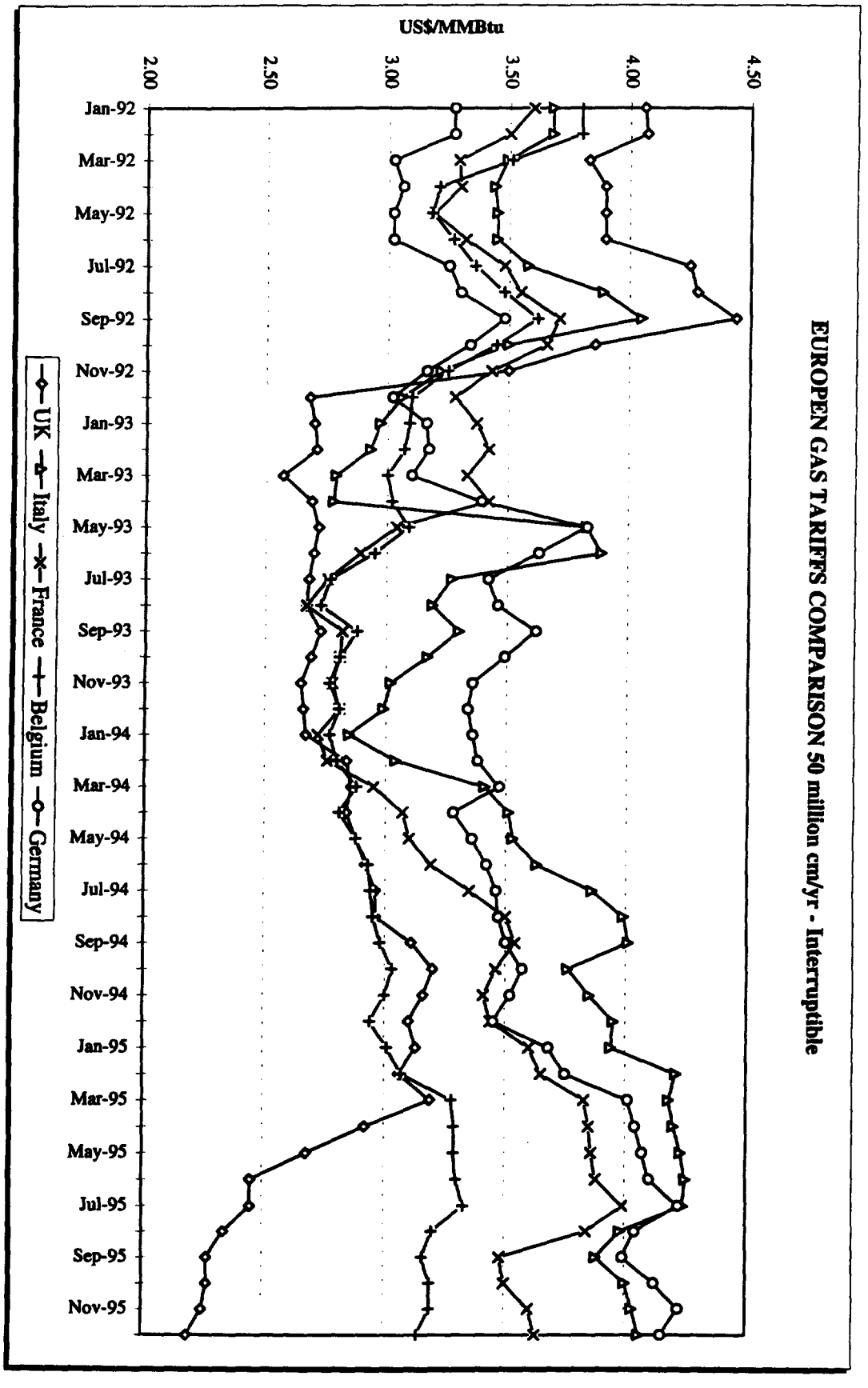
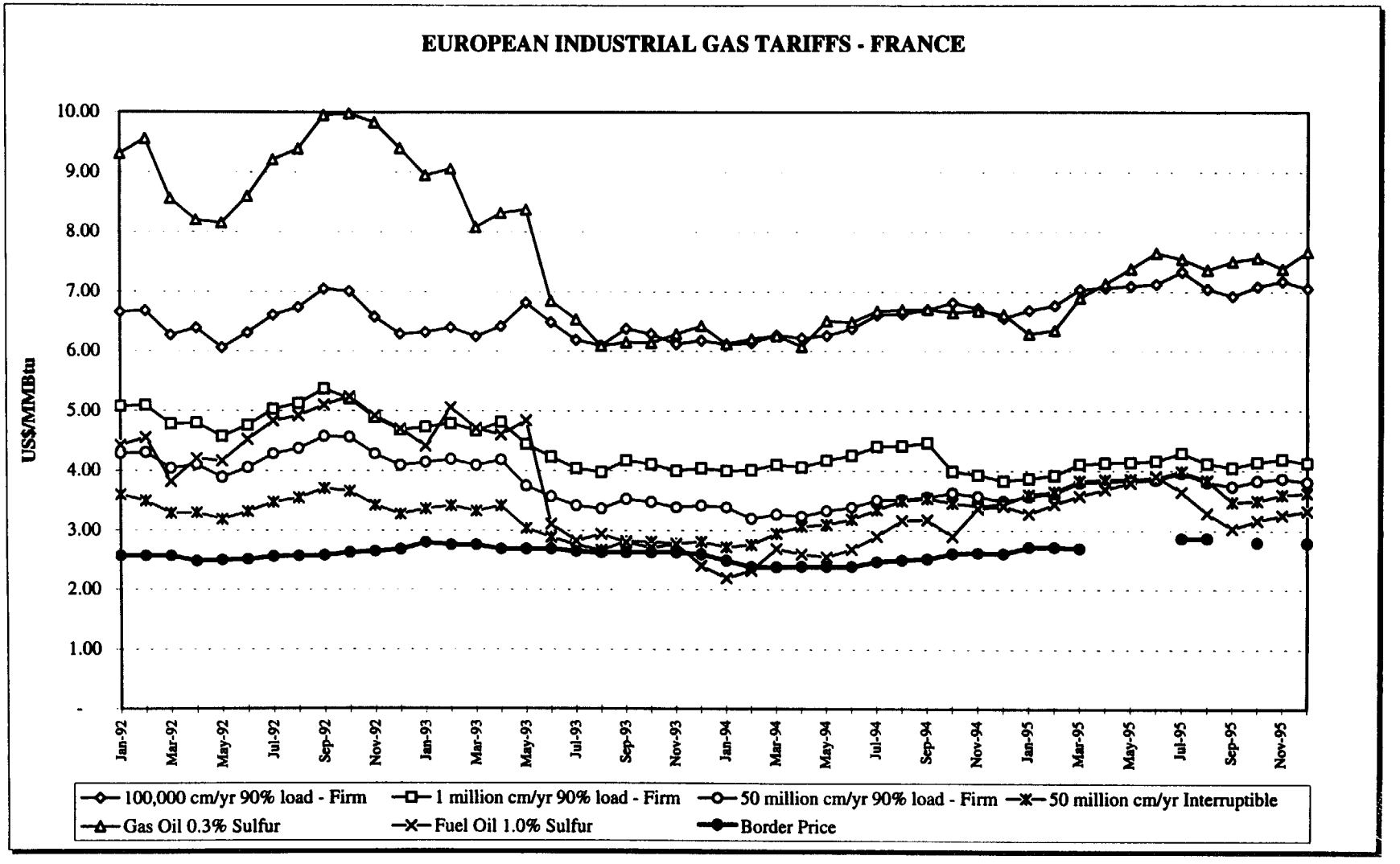
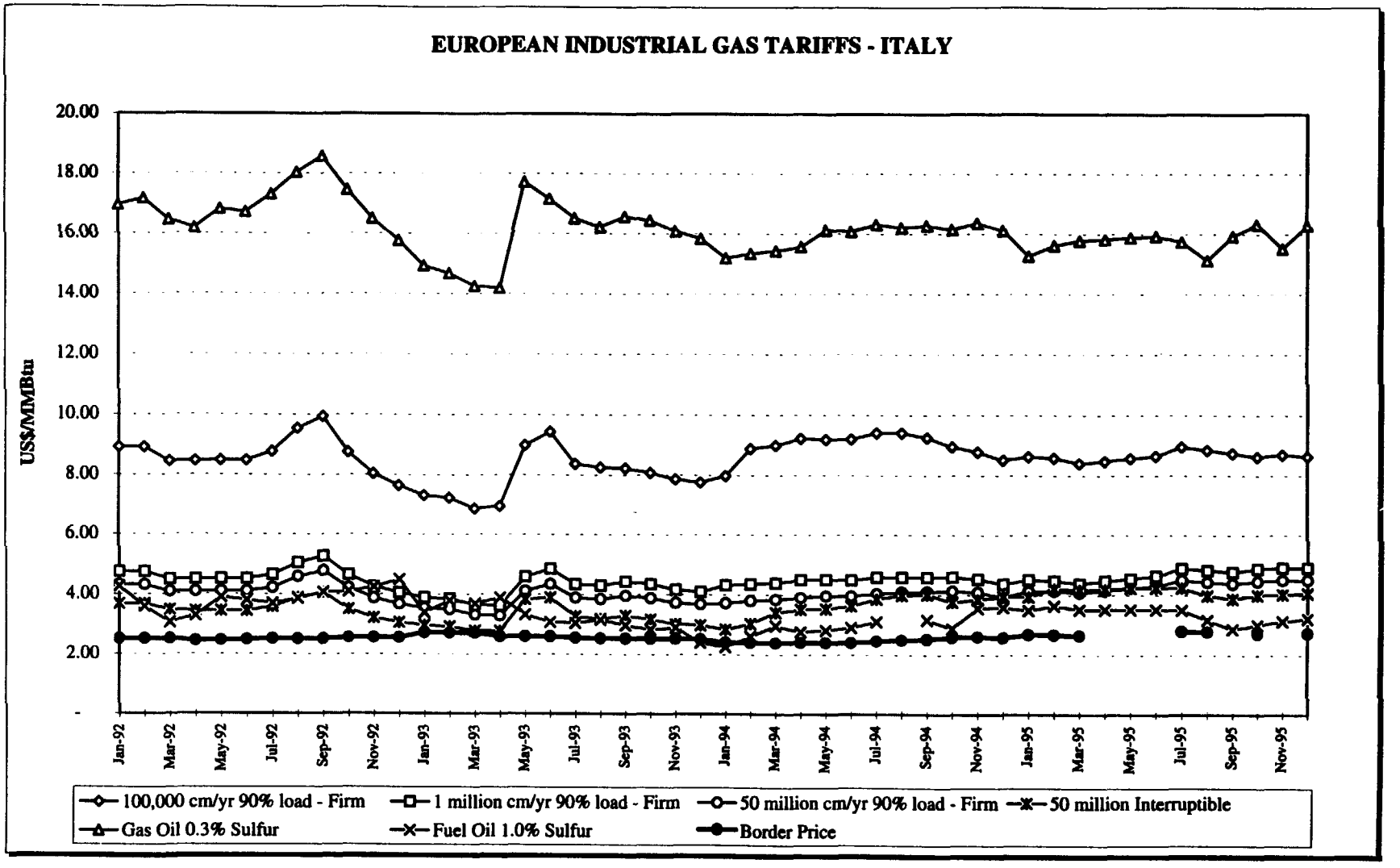

EUROPEN GAS TARIFFS COMPARISON 50 million cm/yr - Interruptible
US$/MMBtu
4.50
4.00
3.50
3.00
2.50
2.00
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
UK
Italy
France
Belgium
Germany

Chart11

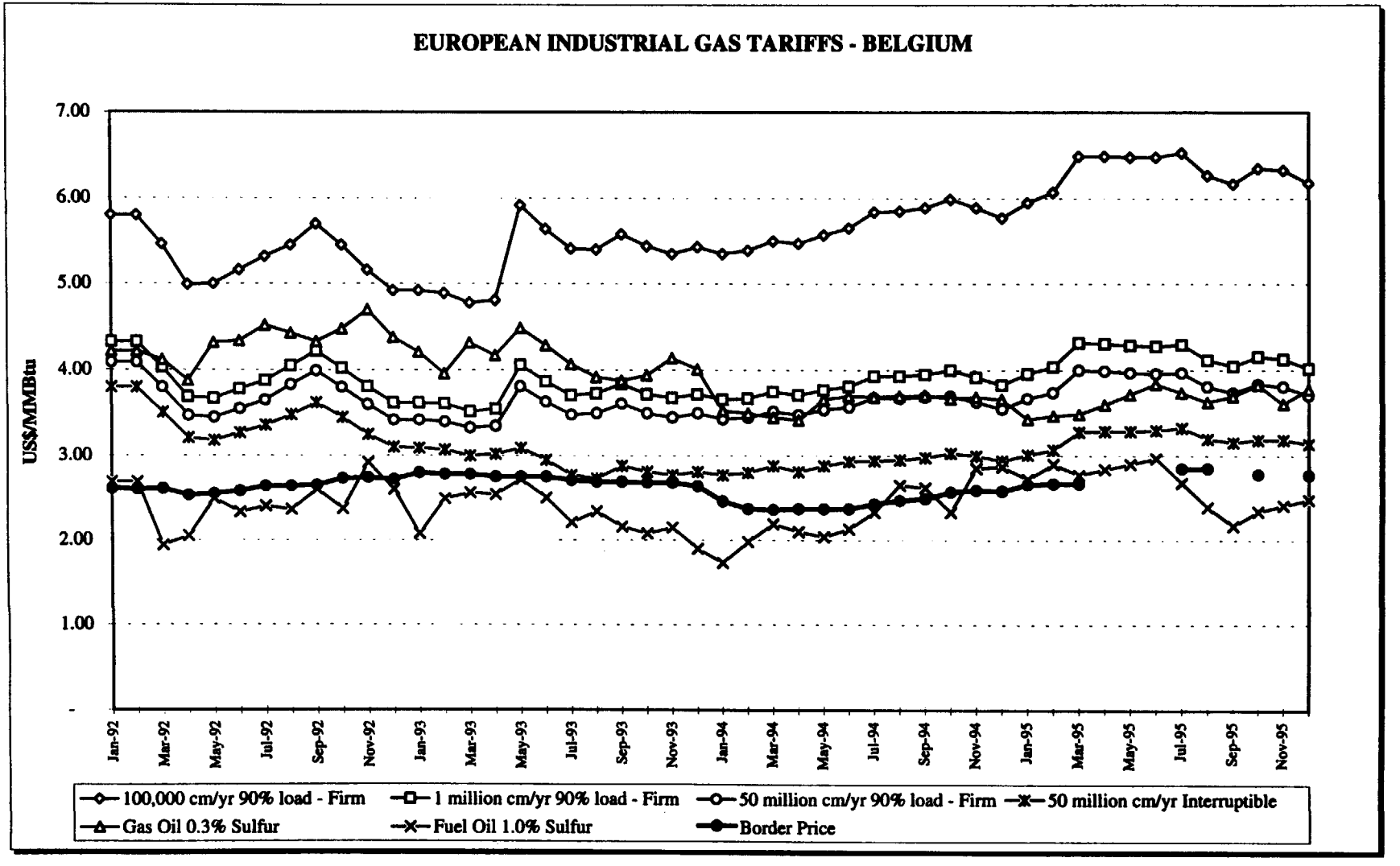
Chart2


EUROPEAN INDUSTRIAL GAS TARIFFS - FRANCE
US$/MMBtu
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
100,000 cm/yr 90% load - Firm
1 million cm/yr 90% load - Firm
50 million cm/yr 90% load - Firm
50 million cm/yr Interruptible
Gas Oil 0.3% Sulfur
Fuel Oil 1.0% Sulfur
Border Price

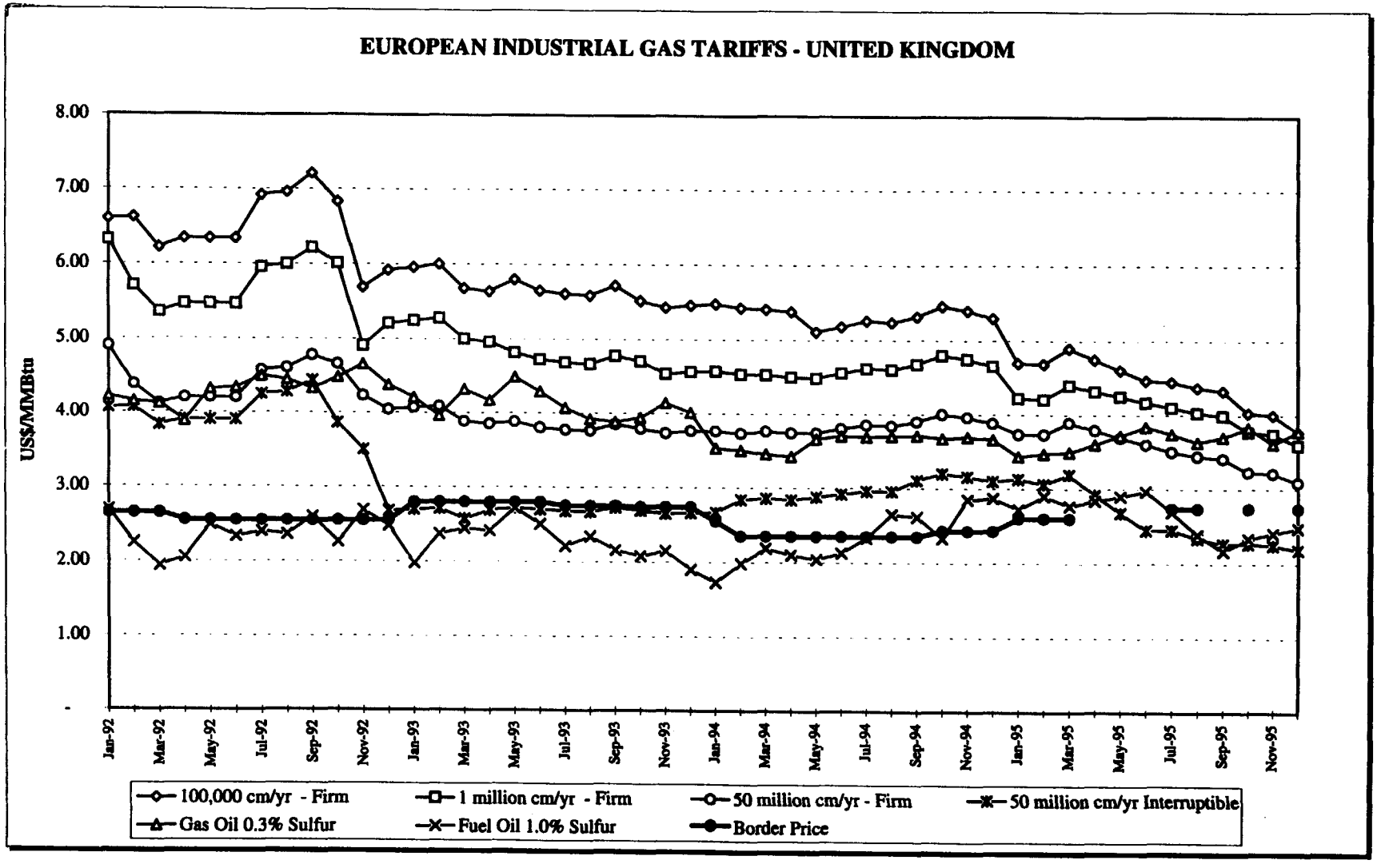
graph I


EUROPEAN INDUSTRIAL GAS TARIFFS - ITALY
US$/MMBtu
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
100,000 cm/yr 90% load - Firm
1 million cm/yr 90% load - Firm
50 million cm/yr 90% load - Firm
50 million Interruptible
Gas Oil 0.3% Sulfur
Fuel Oil 1.0% Sulfur
Border Price

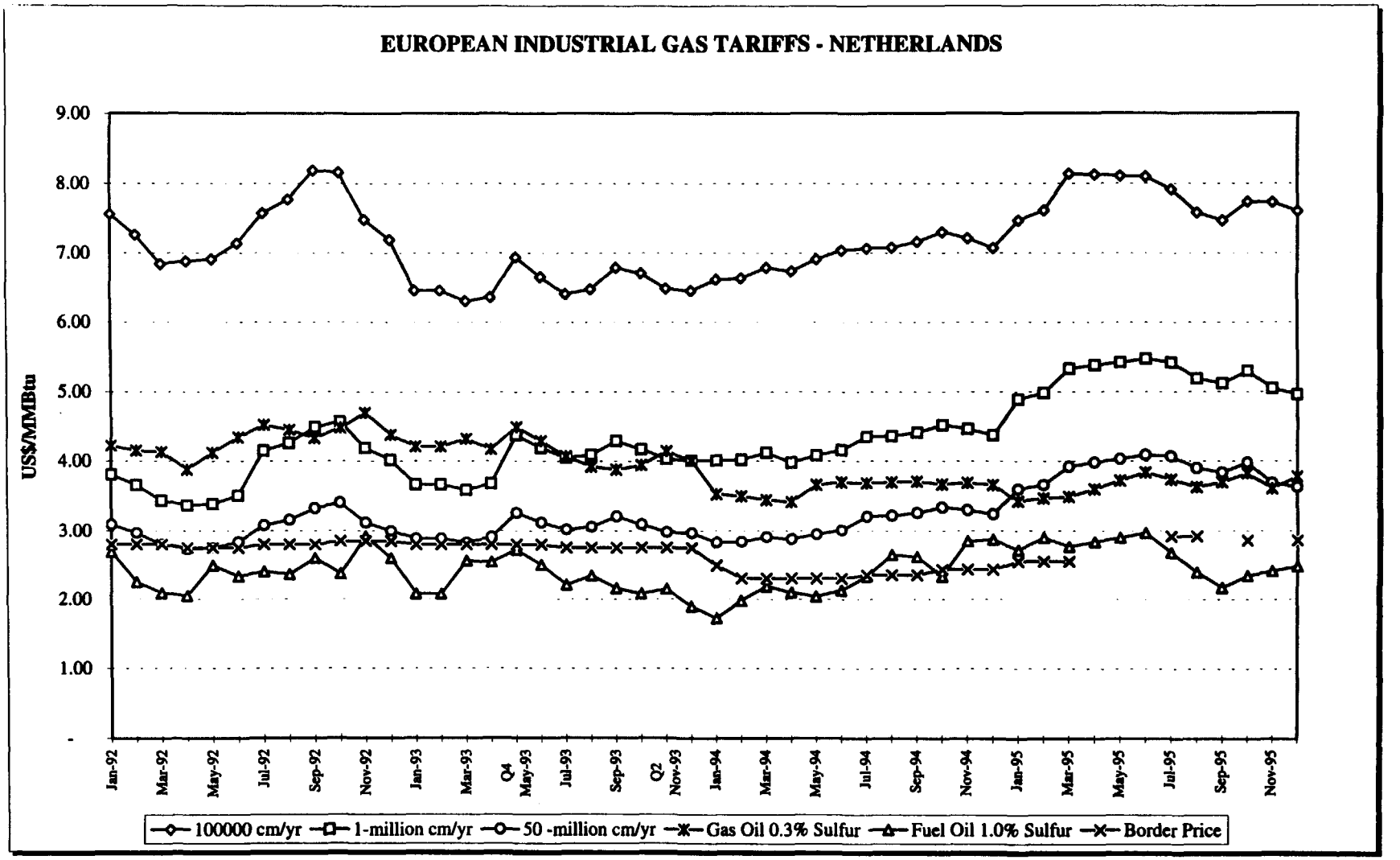
graph B


EUROPEAN INDUSTRIAL GAS TARIFFS - BELGIUM
US$/MMBtu
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
100,000 cm/yr 90% load - Firm
1 million cm/yr 90% load - Firm
50 million cm/yr 90% load - Firm
50 million cm/yr Interruptible
Gas Oil 0.3% Sulfur
Fuel Oil 1.0% Sulfur
Border Price

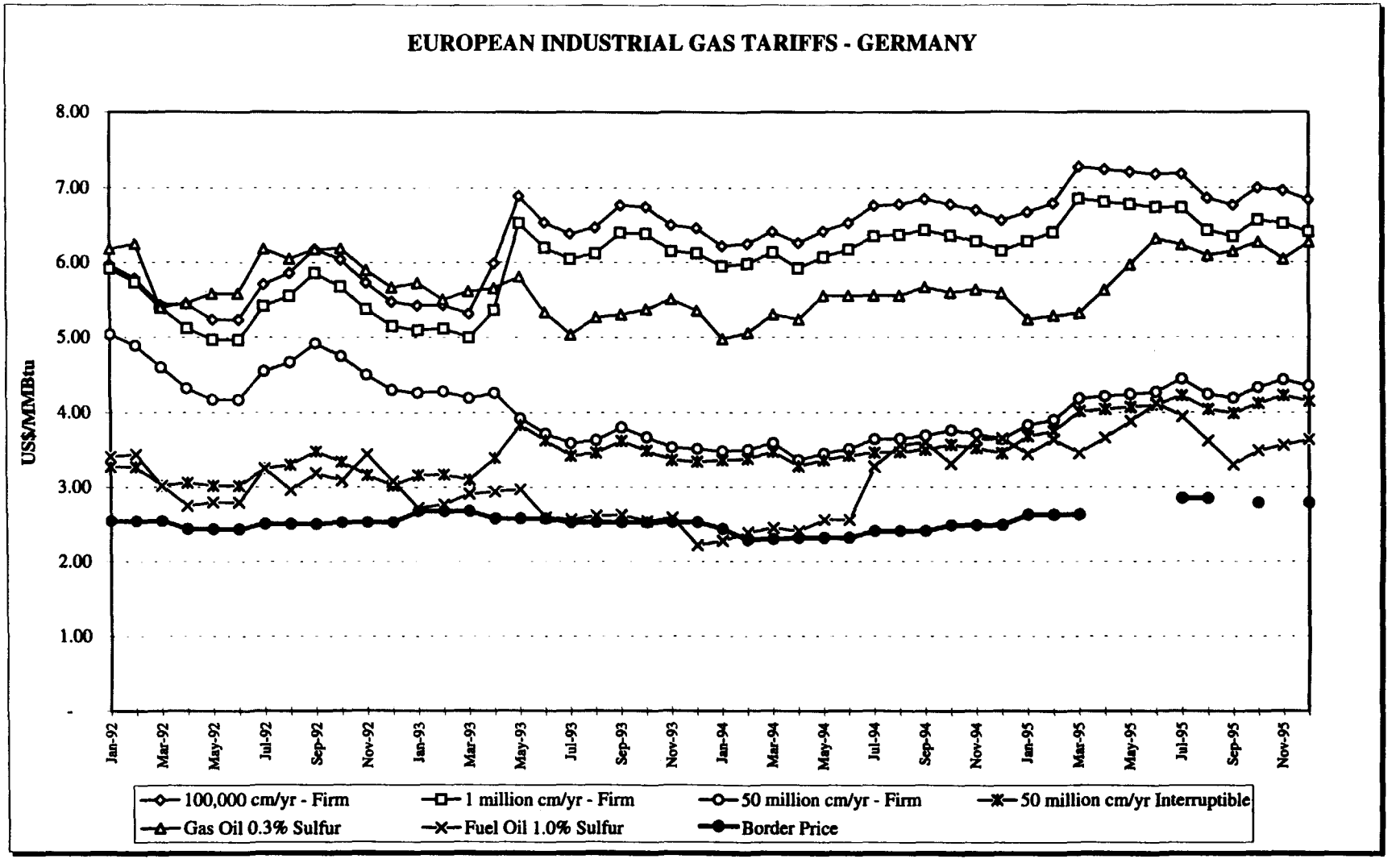
graph UK


EUROPEAN INDUSTRIAL GAS TARIFFS - UNITED KINGDOM
US$/MMBtu
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
100,000 cm/yr - Firm
1 million cm/yr - Firm
50 million cm/yr - Firm
50 million cm/yr Interruptible
Gas Oil 0.3% Sulfur
Fuel Oil 1.0% Sulfur
Border Price

graph Nth


EUROPEAN INDUSTRIAL GAS TARIFFS - NETHERLANDS
US$/MMBtu
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
Q4
May-93
Jul-93
Sep-93
Q2
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
100000 cm/yr
1-million cm/yr
50 -million cm/yr
Gas Oil 0.3% Sulfur
Fuel Oil 1.0% Sulfur
Border Price

graph G


EUROPEAN INDUSTRIAL GAS TARIFFS - GERMANY
US$/MMBtu
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-92
Mar-92
May-92
Jul-92
Sep-92
Nov-92
Jan-93
Mar-93
May-93
Jul-93
Sep-93
Nov-93
Jan-94
Mar-94
May-94
Jul-94
Sep-94
Nov-94
Jan-95
Mar-95
May-95
Jul-95
Sep-95
Nov-95
100,000 cm/yr - Firm
1 million cm/yr - Firm
50 million cm/yr - Firm
50 million cm/yr Interruptible
Gas Oil 0.3% Sulfur
Fuel Oil 1.0% Sulfur
Border Price

FRANCE

Transmission Company	:	Gaz de France (GdF)
Owned by	:	Government (100%)
Regulation	:	Ministries of Industry and Economy and Finance
Imports of gas	:	From Netherlands, Norway, Soviet Union, Algeria. Legal Monopoly of GdF.
Exploration and production (on national territory)	:	(Lacq field) limited and declining. Production carried out by oil companies, especially ELF (56% State owned) (about 97% of domestic output derives from ELF subsidiary).
Transport/Pipelines	:	Virtual monopoly of GdF except for: - Public or semi-public undertakings - The South West region: gas is transported by SNGSO (GdF 30%, ELF 70%).
Distribution	:	Virtual monopoly of GdF except for municipal undertakings and small sized gas companies.
Storage	:	Free under licence requirements imposed by the Minister for Interior Affaires.
Special characteristics	:	- Decentralisation (11 transmission regions, 100 distribution areas) - Close relationship with EdF (Electricité de France).

3.1. Gas tarification in France

Tariffs for domestic and tertiary-sector customers and for small-scale industry

Tariffs for these customers comprise:

- an annual standing charge,
- and a rate or rates per kWh consumed.

There are six tariffs, which vary according to the customer's annual consumption and in some cases the time of year:

- The basic tariff for annual consumption below 93 m^3 (normally for cooking),
- Tariff B0 for annual consumption between 95 and 665 m^3/year (normally cooking and hot water),
- Tariff B1 between 665 and 2 850 m^3 per annum (individual heating, hot water and/or cooking)
- Tariff B21 from 2 850 to between 14 250 and 33 200 m^3 per annum. (collective provision of heating and/or hot water).
- Tariff B2S for consumption in excess 14 250 - 33 200 m^3 per annum. Tariff B2S is seasonally adjusted: winter consumption (November to March) is charged at a higher rate than summer consumption (April to October),
- The contingency tariff applying to back-up or stand-by supplies for other energy sources (ratio annual quantities/daily offtake less than 70 days).

For customers whose consumption lies between 14 250 and 33 200 m3, the choice of tariff B2I or B2S depends on the pattern of consumption and each case has to be calculated separately.

Standing charges are standardized throughout the public distribution network of GDF, as are the commodity rates of the basic and B0 tariffs. The commodity rates for tariffs B1, B2I and B2S are subdivided into six levels depending on the cost of bringing the gas to the public distribution network.

Tariffs for large industrial customers

Large industrial customers (consumption above 0.48 million m3/year) are subject to tariff with a more complex structure, known as subscription tariffs, for gas used for industrial purposes.

These subscription tariffs are made up of four components:

- an identical annual subscription charge for every point on the grid;
- an annual standing charge based on the daily winter demand which the customer has requested; payment of this standing charge "entitles" the customer to this daily offtake throughout the year;
- a reduced annual standing charge based on any additional daily demand which the customer has requested for the seven summer months only;
- commodity charges which differ according to season (winter/summer) and block of consumption:
    - block 1: up to 2.28 million m3/year,
    - block 2: above 2.28 million m3/year.

The charges in summer are lower than those in winter.

These tariffs have two versions corresponding to the type of network to which the customer's installations are connected, namely the SRS tariff for installations connected to the public distribution network and the STS tariff for installations connected directly to the transmission grid.

A single tariff is applied to the major interconnected transmission routes linking the country's sources of gas; tariffs (excluding subscription charges) for the minor routes are obtained by adding the charges specific to each one to this tariff (system of tolls). SRS tariffs are calculated from STS tariffs by adding a toll for transfer via the public distribution network.

These tariffs apply to industrial customers only and are subject to supply constraints and market conditions: there is basically no obligation to supply gas at these tariffs.

Contracts are concluded for a three-year period.

Special contracts

The GDF may ask its large customers (those using more than 1 million m3/year) if it may purchase from them the option of interrupting supplies. Under this arrangement customers undertake to cease their consumption of gas at GDF's request. The period of notice before supplies are interrupted is fixed contractually, varying from a few hours to fifteen days. The GDF may use this option when there is a supply crisis or at times of peak demand, customer notice permitting. The length of time for which supply may be interrupted is not fixed.

Customers participating in this arrangement must therefore be able to switch over readily to an alternative source of energy and must therefore maintain back-up equipment in working order. Customers must also undertake to consume at least 80% of the annual quantities stipulated in the contract.

The GDF rewards customers offering the option of interruptibility through flat-rate rebates when an alternative source of energy is domestic heating oil, and through guaranteed prices for heavy fuel oil when emergency use of this has to be made.

Price regulation

Tariffs are a matter of public record: if there is any change to existing rates, a new price list must be registered.

The tariffs for the public distribution network are regulated; the average rate of change is set by order of the Ministry of Finance.

Changes in prices for large industrial customers are partially unregulated: the GDF registers price lists with the Ministry of Finance, which has the right to oppose them.

In conjunction with the regulatory arrangements, the GDF and the State have concluded a contract defining their relationship for the period 1991 to 1993. Under this contract the GDF undertakes to make productivity gains and to pass some of the benefits on to domestic customers. The State, for its part, undertakes to permit the GDF to have the necessary tariff rates to reduce its debt.

GDF's prices vary according to supply costs and inflation. The cost of raw materials assumes greater importance with large industrial customers than it does with domestic customers, who are more expensive in terms of investment and management costs.

Taxation

Gas sales are subject to value added tax, which may be recovered by registered industrial and tertiary-sector customers.

In the case of domestic customers, VAT is applied at 5.5% on standing charges and at 18.6% on commodity rates. The VAT of 1.6% has been unchanged since July 1982.

Furthermore, a special tax on the use of natural gas as an industrial fuel (TICGM: Taxe Intérieure à la Consommation du Gaz Naturel) was instituted on 1st January 1986. In 1991 this tax was levied at the rate of 0.012 $\$/m^3$. Exemptions apply to gas used to heat living accommodation or as a raw material. TICGM is applied when annual consumption exceeds 0.48 million m3/year, with a abatement of 38,000 m^3/month.

GERMANY

Transmission Company	:	No dominant company but many private companies in which there can be some public sector influence through direct and indirect shareholdings.
Regulation	:	Supervisory role for Government.
Exploration and production (on national territory)	:	Supply dominated by private companies owned by international oil companies such as BP, Mobil, Esso and Shell. Licence (for exploration) and authorization (for production) granted by the lander operating. No State participation. Taxes on production of gas and oil abolished in principal producing lander. Fuels fees and State royalties have to be paid to the relevant land authority.
Imports of gas	:	80% of imports (from Netherlands, Norway, Soviet Union, Denmark) accounted for by only 3 companies of which Ruhrgas (75% of total West Germany imports).
Transport/Pipelines	:	About 15 companies responsible for long distance carriage. Dominant ones: privately owned companies such as Ruhrgas, Thyssengas, Bed Erdgas und Erdol, GSD, EWE...
Distribution	:	More than 500 gas distribution companies publicly, privately or municipally owned (that may also supply electricity and/or water).
Storage	:	Objection power of land authority for any gas pipeline project. Consent to storage projects may be refused by land authorities.

3.2. Gas price formation in Germany

Gas prices in the Federal Republic of Germany take their orientation from competition on the market where gas is seeking the same outlets as other sources of energy. The prices that users pay for gas are negotiated between the supplier and the consumer, each evaluating the contract that is being offered by a set of appropriate criteria.

These criteria include, on the other hand, the prices at which competing sources of energy are being offered and their efficiencies and, on the other hand, the cost that the consumer incurs for the conversion of the energy delivered by the supplier into useful energy.

In the industrial sector, the prices at which major users receive gas are freely negotiated on a case-by-case basis. As these negotiations are guided by the principle of market orientation, gas prices paid by industrial users in the Federal Republic of Germany cannot be determined by standard rates. On the other hand, competition is controlled by the circumstances of each case and, energy, such as heavy fuel oil, gas oil, coal, LPG and electricity are offered, vary for the different regions and the different applications. Market-oriented industrial gas prices vary accordingly.

The customer pays a service charge and thus acquires the right to use gas delivery facilities and services, i.e. ducts, pressure valves, storage facilities, gas meters and the company's supply guarantee. This service charge may be compared to storage and investment costs the individual customer would have to pay for fuel oil. It may also be considered to be an adequate balance of competition created by the price.

Generally unlimited in time, the right to use supply facilities may be limited by special contracts. This special tariff provides low service charges according to the length of supply periods, or no service charge at all for customers in industry with two-way heating equipment suitable for other forms of energy as well, including stored fuel oil.

For the different industrial consumer categories, gas companies throughout the Federal Republic of Germany are confronted with similar competitive environments. In the case of the I1 to I3 standard consumers, gas oil is the chief competitor, in the case of the I4 consumer, gas competes with both gas oil and heavy fuel oil and for I5 sales, heavy oil is the most important alternative to gas.

The gas prices that are negotiated only reflect market conditions at the time of negotiation. As this situation changes continually, it is necessary to adjust the agreed market-oriented price.

Such adjustment can be achieved by price indexation formulae of the type widely used by the gas industry. Fuel oil price indexation formulae pegging the price of gas to the prices of heavy fuel oil and gas oil are, for example, agreed upon with industrial gas users.

Gas prices are adjusted at agreed regular intervals. Quarterly adjustment on 1st January, 1st April, 1st July and 1st October is frequent. On each adjustment date, the price of gas is modified to reflect average heavy fuel and gas oil prices during an earlier reference period.

In the Federal Republic of Germany, the oil product prices included in the price adjustment formulae are the prices published each month by the German statistical office.

Apart from firm gas supplies, interruptible supplies are offered to industrial users and to power stations. Interruptible supplies are agreed in a contract negotiated between the gas company and the user. Users opting for these supplies normally operate large boiler plants. Under such a contract, the company is entitled to interrupt gas supplies fully or in part, if and when certain agreed criteria are fulfilled. During the duration of the interruption, the user employs another fuel which is often heavy fuel oil. The user therefore needs dual fuel equipment as well appropriate fuel oil storage tankage.

The gas company's right to interrupt supplies may, for instance, be exercised throughout the year or during a limited period of the year or below an agreed average daily temperature.

For similar gas quantities and similar market conditions, interruptible supplies of gas are at present sold at a price which is between 5% and 10% below the price of firm gas, chiefly to account for the extra capital charges and operating expenses incurred by the user for dual fuel equipment.

Natural gas supply is subject to a purchase tax of 14%. When natural gas is used for heating, an additional natural-gas tax is levied at a rate of 0.024 $/cm as of 1 July 1991 (before: 0.017 $/cm).

THE NETHERLANDS

Transmission Company	:	Gasunie
Owned by	:	- Government (10%) - EBN (Energie Beheer Nederland) (100% state owned, but managed for the state's behalf by DSM (Dutch State Mines) privatized in 1989) (40%). - SHELL (25%), ESSO (35%)
Regulation	:	Influence exercised by the Government on all aspects of gas industry.
Exploration and production (on national territory)	:	Several kinds of licences granted by the Ministry of Economic Affairs Interest of State: 50% in onshore and offshore concessions. Production from Groningen: by NAM (Consortium owned by Shell and Esso).
Imports of gas	:	The statutory rule gives Gasunie a de facto monopoly of gas supply for gas produced in the Netherlands and intended for domestic consumption. Gas produced outside the Netherlands may be imported especially from Norway (Troll), by Dutch gas users but with the approval of the Ministry of Economic Affairs.
Transport/Pipelines	:	Onshore pipeline network owned by Gasunie. Although there is no exclusive right to transport, it belongs in practise to Gasunie. Offshore: Northern gas transport system (NOGAT) (EBN:45% share, ELF Petroland, NAM).

Distribution : Gasunie supplies gas directly to industrial users and power producers consuming more than 2 million cubic metres a year.
Distribution companies, mostly owned by the local authorities sell gas to other consumers.
New contacts agreed so that each distribution company will eventually pay the same city-gate price.

3.3. Gas tarification in the Netherlands

Pursuant to the provisions of the Agreement, the prices stated against a, b, c, d and e below shall be applicable successively in any year with effect from 1st January, 1990.

It has to be noted that approval by the Minister is required for all prices charged by GASUNIE.

Zone	Offtake in m^3	Price in US cents per m^3 supplied
a.	0 - 170 000	(G:500) * 37,2 - 1,3 plus a standing charge of US$ 39.14 per annum
b.	170 000 - 10^6	(P:500) * 38,2 + 2,6
c.	10^6 - 10.10^6	(P:500) * 38,2 + 1,02
d.	10.10^6 - 50.10^6	(P:500) * 38,2 + 0,45
e.	> 50.10^6	(P:500) * 36,3 + 0,71

G is understood to mean: the value, averaged over the six months before the half-year for which the price applies, of gas oil price, plus excise duty, fuel storage surcharge (COVA surcharge and trade and transport surcharges). This value shall be the arithmetic mean of the high and low monthly quotations for gas oil published in Platt's Oilgram Price Report in US dollars per tonne under "barges FOB Rotterdam".

P is understood to mean: the value, averaged over the six months immediately preceding the quarter for which the price applies, of fuel oil with a sulphur content of 1.0% by weight, plus excise duty and trade and transport surcharges. This value shall be the arithmetic mean of the high and low monthly quotations for fuel oil with a sulphur content of 1% by weight as published in Platt's Oilgram Price Report in US dollars per tonne under "Barges FOB Rotterdam".

The environmental levy of natural gas shall be added to the price per m3 - 1.7$.

If in any year the offtake exceeds 1 million m^3 and the operating period (B) in any year is less than 150 days but more than 100 days, the Customer shall be charged compensation over and above the price per m^3 offtake, as follows:

a. (1 - B/150) / 1.763 US cts per m3

b. 0.153 US cents for each m^3 by which the offtake exceeds 1 million m^3 per annum This amount shall be increased by 0.147 US cents for each m^3 by which the offtake exceeds 8.8 million m^3 in that year.

The lower of the amounts given by a and b above shall be charged to the Customer by the Supplier. However, if the operating period is less than 100 days, the compensation shall be calculated as under a above.

A discount of 0.43 US cents on the price m3 offtake shall be given in respect of gas supplied within the provinces of Groningen, Friesland and Drenthe and within the area of the province of Overijssem designated by the Netherlands Government. This discount shall not amount to more than 5% of the price per m3 offtake, excluding any surcharges.

The amount payable by the Customer pursuant to the preceding paragraphs is exclusive of Value Added Tax (18.5%).

ITALY

Transmission Company	:	SNAM.
Owned by	:	ENI (Ente Nazionale Idrocarburi) (100% State owned) + Government
Regulation	:	Ministry of Industry.
Exploration and production (on national territory)	:	Monopoly of AGIP (subsidiary of ENI) but from time to time, joint ventures with private companies. Certain areas exclusively reserved to ENI.
Imports of gas	:	60% of total sales are imported, principally from Algeria, the Netherlands, and the Soviet Union. Responsibility of imports belongs to SNAM.
Transport/Pipelines	:	SNAM's exclusive rights of transport are only in the Po valley area and over pipelines carrying Italian gas. Some form of common carriage is likely to be permitted in the near future for third parties via pipeline system owned by Snam.
Distribution	:	Major distribution of gas through pipeline are: - Snam/Italgas group + about 700 local and regional distribution companies, both private and municipally owned.

3.4. Gas tarification in Italy

The tariff structure is based on agreements between the national methane gas company, SNAM, and the industrial associations (CONFINDUSTRIA and CONFAPI) (CIP, an inter ministerial committee has the right to reject it). It is applied nationally without distinction to all sectors of production and regardless of the type of supply network (transport or urban distribution) to which users are connected. Industrial users connected to urban distribution networks are subject to the same conditions as applied by SNAM for direct use if the annual offtake exceeds 200 000 m3. The current tariff structure stipulates that users with offtakes below this figure should be generally regarded as domestic users, with end tariffs officially fixed in accordance with a special methodology.

Continuous supplies

The tariff for continuous supplies includes a connection charge, a fixed charge linked to the daily production made available by SNAM and a variable charge related to the quantities supplied.

a) Connection charge

422 US$ per month (but reduced by 169 US$ per month from 1 July 1991 to 31 December 1991 and by 84 US$ per month from 1 January 1992 to 30 June 1992).

b) Fixed charge (TF)

Calculated using the formula: TF = Ca x I where:

Ca = demand charge, expressed in US$ per month for each contracted daily cubic meter. The demand charge Ca is adjusted every six months (1 January and 1 July) in accordance with the trends in the indices of the agreed hourly wages of industrial workers (60% of the calculation) and the wholesale prices of non-agricultural products (40%).

I = user's daily demand (m3/day); the fixed charge is increased if daily offtakes exceed the contracted demand by more than 11-15% (depending on the size of the user).

c) Variable charge (TP)

The unit value of the variable charge (TP) is calculated using the formula: TP = Ba x Ks x S where:

Ba = base value of the variable charge (US$/m3)

Ks = average band coefficient calculated on the basis of the following coefficients (from 1 to 0.85).

S = coefficient to take account of seasonal reductions: 0.94 for offtakes from April to September inclusive and 1.00 for the rest of the year.

The following arrangements apply to offtakes by establishments owned by the same company and involved in similar production:

1. Single connection charge (applied to the establishment with the greatest offtake);

2. Reduction (from 0.5% to 2%) of amounts charged according to the number of establishments involved.

A reduction is also available to consumers whose monthly offtakes are constant throughout the year. This reduction may be as much as 2.5% of the annual bill.

Lastly, at the end of the calendar year consumers who have consistently complied with the conditions of their contracts are accorded a reduction of 1.5% of the total bill for the offtake of the previous 12 months.

The above tariff is applied to almost all users. Consumers with very irregular offtakes are eligible for two other scales (low consumption and one-part tariff) which are better suited to their specific requirements.

Interruptible supplies

There are two tariff scales for interruptible supplies. Eligibility depends on the duration of the maximum interruption in each calendar year.

"Short" interruptibility: maximum interruption, 20 days/year.
"Long" interruptibility: maximum interruption, 90 days/year.

Interruptible supplies are intended for consumers with installations using heavy fuel oil and with a certain minimum annual offtake (1 million m^3 for "short" interruptibility and 2 million m^3 for "long" interruptibility).

The price of natural gas is calculated as follows:

P = 0.875 x (0.10 x IM + M) x Sm x Kstag x (1 + P.R./1200) x Reg where:

P = Price of gas in US$/$m^3$

0.10 = 1986 value in $/kg of ATZnaz

IM = (0.8 x ATZNAZ/ATZNAZo + 0.2 x ATZEST/ATZESTo) where ATNAZ and ATZEST are the price of high sulphur heavy fuel oil as indicated for the two-part tariff for continuous supplies, both in relation to the same month of natural gas offtake; ATZNAZo = 0.1 US$/kg (1986 value of ATZNAZ); ATZESTo = 0.093 US$/kg (1986 value of ATZEST)

M = surcharge which varies according to the type of interruptibility ("long" or "short") and the location of the consumer's establishment.

SM = average band coefficient, which varies according to the type of contract:

"long" interruptibility: (from 1 to 0.98)
"short" interruptibility: (from 1 to 0.96).

Kstag = coefficient based on the seasonal reduction: 0.98 for offtakes from April to September inclusive and 1.00 for the rest of the year.

P.R. = value in percent of the bank prime rate applicable in each month; used to take account of the time lag between consumption and payment of fuel oil and natural gas.

At the end of each calendar year the consumers who have consistently complied with the conditions of their contracts are accorded a reduction of 1.25% on the average price for the annual supply of gas.

Tax

Natural gas for industrial use is subject to a consumption tax of 0.017 US$/m3. Exemption is granted in the case of use for the generation of electricity and internal use within refineries and installations where hydrocarbons are converted into chemicals. VAT rate: 9-19%.

UNITED KINGDOM

Transmission Company	:	British Gas.
Owned by	:	Private shareholders (privatization in 1986).
Regulation	:	Integrated system of regulation of gas: central mechanism charged to regulate the gas supply industry.
Exploration and production (on national territory)	:	Several kinds of licences onshore an offshore. Granted by the Secretary of State of Energy. No State participation requirement. Major players include Shell, Esso, BP and BG.
Imports of gas	:	From Norway and Algeria. Limited: about 80% of BG's total supplies come from UKCS.
Transport/Pipelines	:	Pipeline infrastructure is a natural monopoly owned by BG but can be used by third parties under specific conditions: common carriage system.
Distribution	:	2 categories of suppliers of gas to whom an authorization may be granted: - Public gas supplier (British Gas is the only one) operating with a defined geographical area, - Suppliers of gas to specific premises or categories of premises. BG, as a public gas supplier, must meet all requests for interruptible suppliers of gas, as far as possible.

3.5. Gas tarification in the United Kingdom

Tariff customers

Domestic and smaller industrial and commercial customers, i.e. those consuming up to 69 400 m3 per year, are supplied under published tariffs. Since 1 March 1990, these tariffs have been standard across the whole of Geat Britain. There are two main types of tariff, the credit tariff, which applies to the majority of domestic sector sales, and the domestic prepayment tariff, where consumers pay in advance via a meter. Both tariffs incorporate a standing charge and charges for each unit consumed. The rate payable per GJ varies according to the level of consumption, reducing as consumption increases.

Non-tariff customers

Customers taking more than 69 400 m3 per year can be supplied by British Gas or by another supplier. For supplies by British Gas customers are normally supplied according to the prices and therms (or GJ) set out in published schedules, although they can be supplied under British Gas's tariffs. These schedules were introduced in May 1989 following recommendations in the 1988 report by the Monopolies and Mergers Commission, and are intended to stimulate competition in the market. Suppliers other than British Gas negotiate individual contracts with customers.

The prices within British Gas's schedules are determined according to a number of factors, including the size of the load, the number of premises supplied, whether the supplies are firm or interruptible and the length of the period of interruption. Interruptible supplies are available only to customers consuming more than 555 000 m3 per year. There are different schedules for contracts of different lengths. The schedules do not differentiate according to the use of the gas by the customer. Power station's supplies are generally covered by the schedule for long-term contracts (10-15 years).

In general the schedules in operation in July 1991 incorporate a monthly charge and a unit charge. The monthly charge varies according to the level of annual consumption; the unit charge varies with consumption and also according to the number of premises supplied. There are optional terms in the schedules allowing for prices to be fixed (at supplement of the basic price) or for the prices to be indexed. For firm supplies the schedules also incorporate seasonal pricing factors which increase the price in winter. These factors are as follows:

December, January, February, March	1.0
April, May, October, November	0.95
June, July, August, September	0.85

Since British Gas remains the majority supplier, all prices reported under the Directive for the United Kingdom gas market for 1 July 1991 are these charged by British Gas.

Regulation of gas prices

Since 1987 prices charged by British Gas to the tariff sector have been restricted according to a formula linked to the rate of inflation as measured by the Retail Price Index (RPI). The Director General of Gas Supply has the responsibility of monitoring and enforcing the formula. Under the formula British Gas can increase its prices up to the level allowed by the formula. The formula has had a structure: RPI-X+Y+K.

The first part of the formula, RPI-X, applied to "non-gas costs", that is, all British Gas costs except the purchase cost of gas. British Gas is allowed to reflect increases in these costs in its process up to the rate of inflation minus an efficiency factor (X) set at 2%. The second element in the formula, Y, at present allows British Gas to pass through all the increases in its gas purchase costs into prices. The third element in the formula, K, allows under-shoot or over-shoot in any particular year to be corrected in later years.

Following a review, the formula is more fully developed. It contains a double price cap (a ceiling setting a limit on price rises) - and a new energy efficiency element. One of the two caps is for non-gas costs, and there is a separate cap for gas costs. The formula has the form: RPI-X+GPI-Z+E+K.

The RPI-X element is the same as in the present formula, though X has been increased to 5%. However, the Y element in the formula has been replaced by a new price cap, GPI-Z. This means that British Gas can increase its gas costs in accordance with the movement in special gas price index minus an efficiency factor, Z, set at 1%.

The second new element, E, covers certain energy efficiency expenditure. The K factor is the same as before.

Gas prices to larger consumers outside the tariff sector are not subject to the same regulation. The report published by the Monopolies and Mergers Commission in October 1988 recommended that British Gas be required to publish a schedule of prices at which it was prepared to supply firm and interruptible gas to contract customers. This recommendation was accepted by the Government and price schedules were introduced from May 1989.

No VAT on gas sales.

3.6. Gas tarification in Belgium

There are two types of tariff for industrial uses which depend on the consumption of the customer.

Non-domestic tariffs are designed for those industries which use less than 881 050 M3/year and other non-domestic customers. They are linked to the same indexing system, Iga and Igd, as domestic uses and apply in the whole country.

T.C.	Tariff	m^3/year	Fixed rental	Commodity rate US cts/m^3
I_1	ND1	920 - 13 860	178 Igd	28.1 Iga + 8.53 Igd
	ND2	13 860 - 92 500	456 Igd	28.1 Iga + 6.52 Igd
I_2	ND3	> 92 500	1 572 Igd + 0,14 Igd/MJ (1)	28.1 Iga + 1.34 Igd

(1) by megajoule of maximum daily offtake.

Iga reflects the development of the cost of purchasing gas from Distrigaz by the public authorities; the ex-border price of natural gas is the predominant factor.

Igd partially reflects the development of distribution costs; 31% represent wages and salaries and 25% represent materials.

The industrial tariff covers fixed and erasable supplies to industries consuming more than 881 050 cm per year. I is a national tariff. For fixed supplies, it is not possible for the supplier of natural gas to make any interruption at all except in the event of force majeure. Erasable supplies can be interrupted in winter between 15 November and 15 March on the initiative of the natural gas supplier after a notification, which is agreed on in advance, has been given. The total number of erasure days per winter period may not exceed 35.

This tariff comprises:

- a fixed charge of (US$/month) = $(1-Rh) * 135.5 * RDZ * S_n * K$
- a commodity rate of
  (US$/$m^3$) = $1{,}02 * (G - 0.072) + (0.09) + 0.007 * RDZ * C_{ne}) * P * K$

The parameters in these formulae are defined as follows :

S_n = Sum of the "fixed" S_{nf} and erasable" Sne subscriptions in GJ/h

R_h = hourly regularity factor assessed in accordance with annual consumption (Qa) and the sum of subscriptions (S_n)

R_h = $R_h = Q_a/(8760 * S_n)$

C_{ne} = coefficient of non-erasure between 0 and 1 depending on the degree of erasure.

P = Adaptation coefficient for the commodity charge depending on the use which is made of the gas.

Non specific applications: fixed 1; erasable 0.9
Specific applications: fixed 1.1; erasable 1

K = price reducing factor as a function of the monthly offtake and calculated as follows:
- on the fist, second, third, fourth and fifth block of 1.1 million m^3 : K=1; 0.99 ; 0.98; 0.97; 0.86
- on offtake beyond 5.5 million m^3 : K= 0.95

G = purchase price of the gas at the border in $/m^3$, valid for the supply month and calculated monthly so as to represent the average price of the various types of the gas bought by Distrigaz during the supply month. This cost is monitored by the industrial auditors of the Comité de Contrôle de l'Electricité et du Gaz.

RDZ = monthly revision formula based on wage and material costs.

There is a rental charge for installation which depends on the geographical situation of the customer with respect to the network.

As regards interruptible supplies, i.e. those which can be interrupted at any time on the initiative of the supplier and/or the customer, the gas price is agreed jointly between the two parties.

	Iga	Igd	G	RDZ
07.1991	0.6613	1.1934	0.146	1.496284

VAT rate on gas sales: 17%.

ANNEX 3.4

PETROLEUM PRODUCTS AND ALCOHOL PRICE STRUCTURE

Table 1 **COMPOSITION OF PETROLEUM PRODUCT PRICES IN BRAZIL**
PRICE STRUCTURE AS OF JUNE 29 1993

US$ / barrel	AVERAGE PRODUCT		GASOLINE		DIESEL OIL		JET FUEL		NAPHTHA PETROC.		NAPTHA /GAS		FUEL OIL 1-A		LPG	
EXISTING SYSTEM																
PRODUCTION STRUCTURE (1)			19,4%		37,7%		4,8%		11,5%		0,2%		17,7%		8,7%	
RAW MATERIAL	17,10		17,10		17,10		17,10		17,10		17,10		17,10		17,10	
REFINING COST	1,40		1,40		1,40		1,40		1,40		1,40		1,40		1,40	
AVERAGE COST (PMR) (2)	18,50	40,4%	18,50	21,6%	18,50	34,2%	18,50	50,4%	18,50	80,6%	18,50	99,0%	18,50	79,5%	18,50	69,5%
CROSS SUBSIDY			16,57	19,3%	1,83	3,4%	0,35	1,0%	-2,87	-12,5%	-6,52	-34,9%	-6,82	-29,3%	-13,64	-51,2%
EX REFINERY (excl. tax)	18,50		35,07		20,33		18,85		15,63		11,98		11,67		4,86	
FINSOC/PIS/PASEP	0,91		1,74		1,10		0,62		0,50		0,41		0,52		0,36	
ICMS (refining)	6,99		16,46		1,32		7,53		4,19		3,36		3,52		1,65	
FINANCING COST	1,48		3,12		1,98								0,93		1,20	
OTHERS	2,97		5,33		8,78		3,10		2,64		2,93		2,91		3,61	
EX REFINERY (incl. tax)	30,86		61,72		33,51		30,10		22,96		18,68		19,55		11,68	
F.U.P	4,23	9,2%	6,50	7,6%	7,83	14,5%	0,55	1,5%							2,74	10,3%
BILLED BY REFINERY	35,09		68,22		41,33		30,65		22,96		18,68		19,55		14,42	
DISTRIBUTION MARGIN	2,34	5,1%	2,10	2,5%	1,75	3,2%	2,62	7,1%					1,50	6,5%	8,56	32,2%
FINSOC/PIS/PASEP (DIST.)	1,95		4,26		2,74		0,93						0,60		0,52	
ICMS (DIST.)	1,81		1,81		1,21		1,37						0,54		1,45	
FINANCING COST	0,51		1,21		0,76								0,36			
PRICE BILLED BY DISTRIBUT.	41,69		77,60		47,79		35,57		22,96		18,68		22,56		24,95	
SALES MARGIN	2,75	6,0%	5,44	6,3%	4,92	9,1%									0,72	2,7%
IVVC TAX	1,36		2,70		1,36		1,10						0,72		0,95	
CONSUMER PRICE (inc. tax)	45,80		85,74		54,07		36,67		22,96		18,68		23,28		26,62	
CONSUMER PRICE (excl. tax)	27,81		49,11		34,82		22,02		15,63		11,98		13,18		16,88	
Total taxes	16,00	34,9%	32,30	37,7%	16,51	30,5%	14,65	39,9%	7,33	31,9%	6,70	35,9%	8,81	37,8%	8,54	32,1%
Total financing costs	1,99	4,3%	4,33	5,0%	2,74	5,1%							1,29	5,5%	1,2	4,5%

(1) Average petroleum product yields from Petrobras refineries

(2) "Precio Medio de Realizacion" destined to cover Petrobras expenses

Source: Provided by PETROBRAS during 1993 Gas Sector Mission

Table 2

ANNEX 3.4
Page 2 of 8

Based on average of year 1995 1995 CRUDE OIL PRICE 17 US$ /Bl
ESTIMATED ECONOMIC PRICES OF PETROLEUM PRODUCTS IN SAO PAULO STATE

1995	LPG	NAPHTHA	GASOLINE	KEROSENE	DIESEL OIL	FUEL OIL 1 % S	2 % S	2.8 % S
FOB US GULF- 1995	181.3	173.2	181.4	164.5	151.2	103.1	89.5	87.1
U S $ / T o n								
US cts/Gallon		47.02	50.95	49.5	48.76			
US $ /Barrel	16.0	19.7	21.4	20.8	20.5	16.4	14.2	13.8
US $ /MMBTU	3.89	3.85	4.07	3.75	3.54	2.59	2.24	2.18
AFRA rate %	509	216	216	216	216	150	150	150
WS 100 (Worldscale)	9.83	9.83	9.83	9.83	9.83	9.83	9.83	9.83
Freight cost US$/Ton	50.0	21.2	21.2	21.2	21.2	14.7	14.7	14.7
Insurance/ AFRMM	12.5	5.3	5.3	5.3	5.3	3.7	3.7	3.7
CIF price US$/Ton	243.8	199.8	207.9	191.0	177.7	121.6	108.0	105.5
Losses/ unloading	43.9	4.99	5.20	4.78	4.44	3.04	2.70	2.64
SANTOS US$ /Ton	287.7	204.8	213.1	195.8	182.2	124.6	110.7	108.1
US$/MMBTU	6.18	4.55	4.79	4.46	4.27	3.12	2.77	2.71
US$/Barrel	25.3	23.3	25.1	24.7	24.7	19.8	17.5	17.1
ECONOMIC COST								
Internal tran US$/T	33.0	32.0	25.0	20.0	38.0	3.65	3.65	3.65
Distribution margin	110.0		71.0	47.0	53.0	15.92	15.92	15.92
Total transp. US$/T	143.0	32.0	96.0	67.0	91.0	19.6	19.6	19.6
Economic Cost- Sao Paulo								
Import parity								
US $ /MMBTU	9.25	5.26	6.94	5.99	6.40	3.62	3.27	3.20
US $ /Ton	430.7	236.8	309.1	262.8	273.2	144.2	130.2	127.7
US$ /Barrel	37.9	27.0	36.6	33.2	36.5	22.2	20.3	19.9
Export parity :								
US $ /MMBTU			5.52			2.63	2.28	2.22
US $ /Ton			245.6			105.0	91.1	88.6
US$ /Barrel			29.1			16.2	14.2	13.8

Table 3

STRUCTURE OF ALCOHOL FUEL PRICES (January 1993)

US $/Barrel		Anhydrous Alcohol	Hydrated Alcohol
Selling price by producer	(1)	40,11	37,20
Transport cost difference (Producer plant to mixing plant)	(2)	-0,13	
Cost of mixing for distributor	(3)	0,32	
Sub total		40,30	37,20
Price billed to the distributor	(4)	44,92	37,20
FUPA	(4)-(1)-(2)-(3)	4,62	
Distribution margin	(5)	1,93	1,76
Transport	(6)		1,85
Social taxes	(7)	3,88	2,97
Financing costs	(8)	1,10	
Sub total	(9)	6,91	6,57
Price billed by the distributor	(10)	51,83	38,87
FUPA	(10)-(4)-(9)		-4,90
Sales margin	(11)	4,95	4,95
Consumer price excluding tax	(10)+(11)	56,78	43,82
Tax ICMS	(12)	18,93	14,61
Tax IVVC	(13)	2,34	1,81
Consumer price		78,05	60,24

VALUE OF "FUPA" FUND	Anhydrous Alcohol	Hydrated Alcohol	Total
Alcohol market 1000 M3/month	235,2	825,8	1061
FUPA Million US$/month	6,8	-25,4	-18,6

(2) difference between alcohol transport mixing plants and transport cost component in gasoline price
(3) cost of mixing with gasoline
(4) price of anhydrous alcohol equal to price of gasoline from refineries
(7) PIS, Finsocial, and "quo de previdencia"
(10) Price of anhydrous alcohol = price of gasoline- Price of hydrated alcohol = 75% of gasoline price
(12) Rate of 25%

Table 4

CONSOLIDATION OF SUBSIDY ACCOUNTING
FOR PETROLEUM PRODUCTS AND ALCOHOL **Period January/December 92**

CONTA DERIVADOS"	Million US$/month	
Receipts	**83,0**	100%
FUP component	82,9	99,9%
Difference with import products (Petrobras) (1)	0,1	0,1%
Expenses	**-68,6**	100%
Payment to distribution companies (2)	-29,4	42,9%
Transfer of products by Petrobras (2)	-12,9	18,8%
Difference with import products (1)	-26,3	38,3%
LPG	-12,5	18,2%
Diesel oil	-3,4	5,0%
Naphtha	-8,7	12,7%
Jet fuel	-0,5	0,7%
Fuel oil	-1,2	1,7%
Balance	**14,4**	
CONTA ALCOOL		
Receipts	**60,9**	100%
FUPA components	1,2	2,0%
FUP components	24,6	40,4%
Result of alcohol sales	35,1	57,6%
Expenses	**-80,9**	
Financial & operation costs of Petrobras	-39,0	48,2%
Stock immobilization (financial cost)	-28,9	35,7%
Cost of transfer (incl. port charges)	-5,9	7,3%
Stock maintenance	-0,8	1,0%
Losses	-0,4	0,5%
Administration cost	-2,2	2,7%
Cost of alcohol import	-0,8	1,0%
Payment to distribution companies (3)	-41,2	50,9%
Subsidy to chemical alcohol	-0,7	0,9%
Result of alcohol sales		
Balance	**-20,0**	
CONTA PETROLEO		
Difference from crude oil import by Petrobras	-71,3	100%
From CIF cost (4)	-50,1	70,3%
From exchange rate	-18,6	26,1%
For private refineries (5)	-2,6	3,6%
Balance	**-71,3**	
Consolidated balance	**-76,9**	

(1) Difference between realization price and real import price
(2) Transfer between refineries and terminals for Petrobras, and between distribution bases for companie
(3) To cover difference between consumer price and costs of hydrated alcohol purchase, transport, distrib
(4) Difference between real CIF crude oil import price and CIF price admitted for domestic oil
(5) Difference between price billed by Petrobras (fixed by DNC) and real oil import cost

Table 5 **COMPOSITION OF PETROLEUM PRODUCT PRICES IN BRAZIL**

Proposed modification of ex refinery price structure

Price structure of june 1993

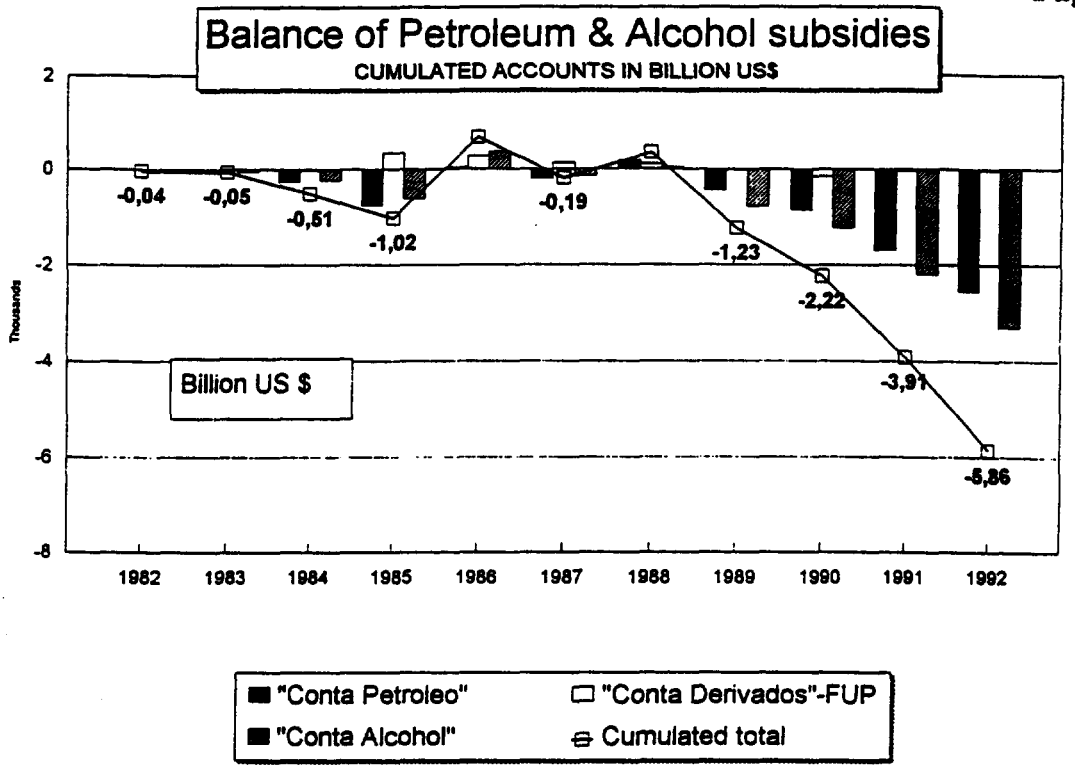
US$ / barrel	AVERAGE PRODUCT	GASOLINE	DIESEL OIL	JET FUEL	NAPHTHA PETROC	NAPTHA /GAS	FUEL OIL 1-A	LPG
EXISTING SYSTEM								
PRODUCTION STRUCTURE (1)		19,4%	37,7%	4,8%	11,5%	0,2%	17,7%	8,7%
RAW MATERIAL	17,10	17,10	17,10	17,10	17,10	17,10	17,10	17,10
REFINING COST	1,40	1,40	1,40	1,40	1,40	1,40	1,40	1,40
AVERAGE COST (PMR) (2)	18,50	18,50	18,50	18,50	18,50	18,50	18,50	18,50
CROSS SUBSIDY		16,57	1,83	0,35	-2,87	-6,52	-6,82	-13,64
BILLED EX REFINERY		35,07	20,33	18,85	15,63	11,98	11,67	4,86
PROPOSED SYSTEM								
INTERNATIONAL PRICES CIF SANTOS (3)	23,81	24,81	27,64	28,22	26,30	26,30	10,94	25,34
PROPOSED EX REFINERY PRICE STRUCTUR (4)	18,50	19,26	21,48	21,93	20,43	20,43	8,50	19,69
CROSS SUBSIDY (5)		15,79	-1,15	-3,08	-4,80	-8,45	3,18	-14,84
BILLED EX REFINERY	22,73	35,07	20,33	18,85	15,63	11,98	11,67	4,86
TRUE ECONOMIC SUBSIDY (6)		10,26	-7,31	-9,38	-10,66	-14,32	0,74	-20,49
F.U.P	4,23	6,50	7,83	0,55				2,74
DISTRIBUTION MARGIN	2,34	2,10	1,75	2,62			1,50	8,56
SALES MARGIN	2,75	5,44	4,92					0,72
DISTRIBUTION/SALES	5,08	7,54	6,67	2,62			1,50	9,28
FINANCING COST	1,99	4,33	2,74				1,29	1,20
TAXES	16,00	32,31	16,50	14,65	7,34	6,70	8,81	6,54
CONSUMER PRICE	45,80	85,76	54,07	36,67	22,98	18,68	23,28	26,62

(1) Average petroleum product yields from Petrobras refineries
(2) "Precio Medio de Realizacion" destined to cover Petrobras expenses
(3) Prices CIF Brazilian coast, imported from US Gulf coast, except for gasoline and fuel oil priced at export parity
(4) Ex refinery prices which cover Petrobras expenses (average 18,5 $/bl) and reflect international price structure
(5) Cross subsidy based on the new product price structure
(6) Economic subsidy = difference between price billed ex refinery and CIF import prices

Source · World Bank calculations from Petrobras data

Fig 1

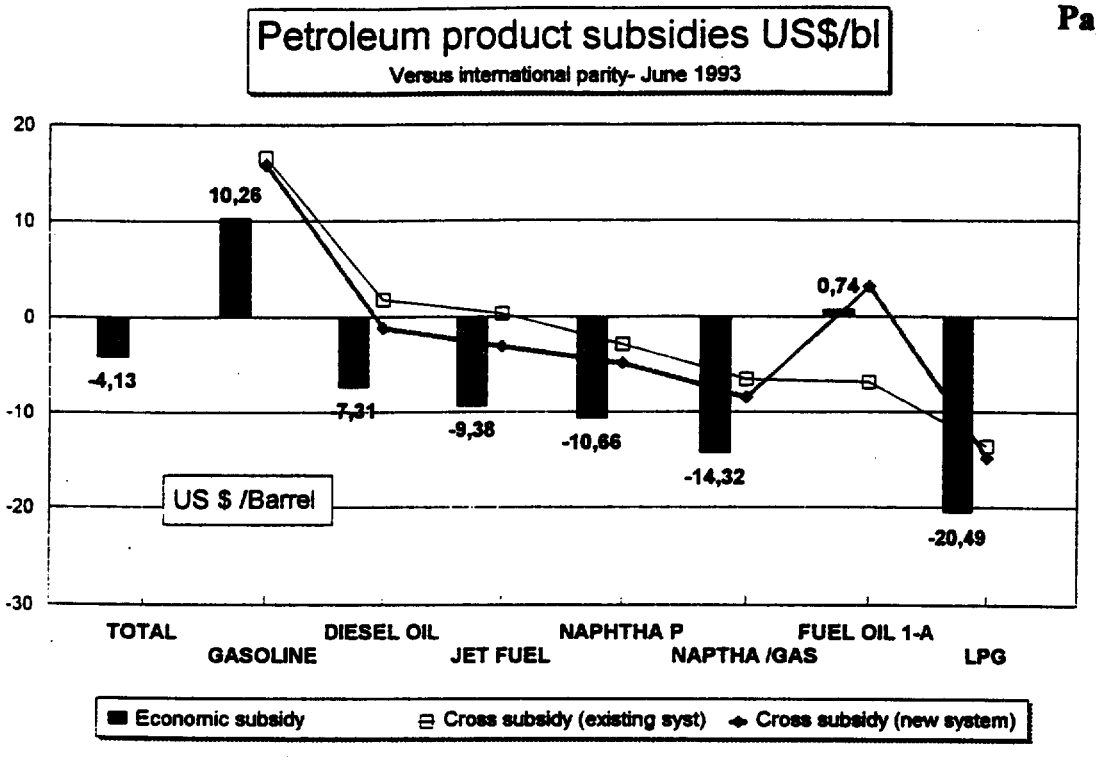
ANNEX 3.4
Page 6 of 8



PETROLEUM SUBSIDIES ACCOUNTS Million US $ cumulated

	Conta Petroleo	Conta FUP	Conta Alcohol	Total Balance
1982			-35	-35
1983			-53	-53
1984	-262	-15	-229	-506
1985	-758	350	-608	-1016
1986	46	277	368	690
1987	-192	142	-136	-187
1988	189	112	52	354
1989	-448	-9	-772	-1229
1990	-856	-149	-1218	-2223
1991	-1688	-27	-2194	-3910
1992	**-2552**	**-12**	**-3295**	**-5858**

Fig.2


Petroleum product subsidies US$/bl
Versus international parity- June 1993
20
10
0
-10
-20
-30
10,26
-4,13
-7,31
-9,38
-10,66
-14,32
0,74
-20,49
US $ /Barrel
TOTAL
GASOLINE
DIESEL OIL
JET FUEL
NAPHTHA P
NAPTHA /GAS
FUEL OIL 1-A
LPG
Economic subsidy
Cross subsidy (existing syst)
Cross subsidy (new system)

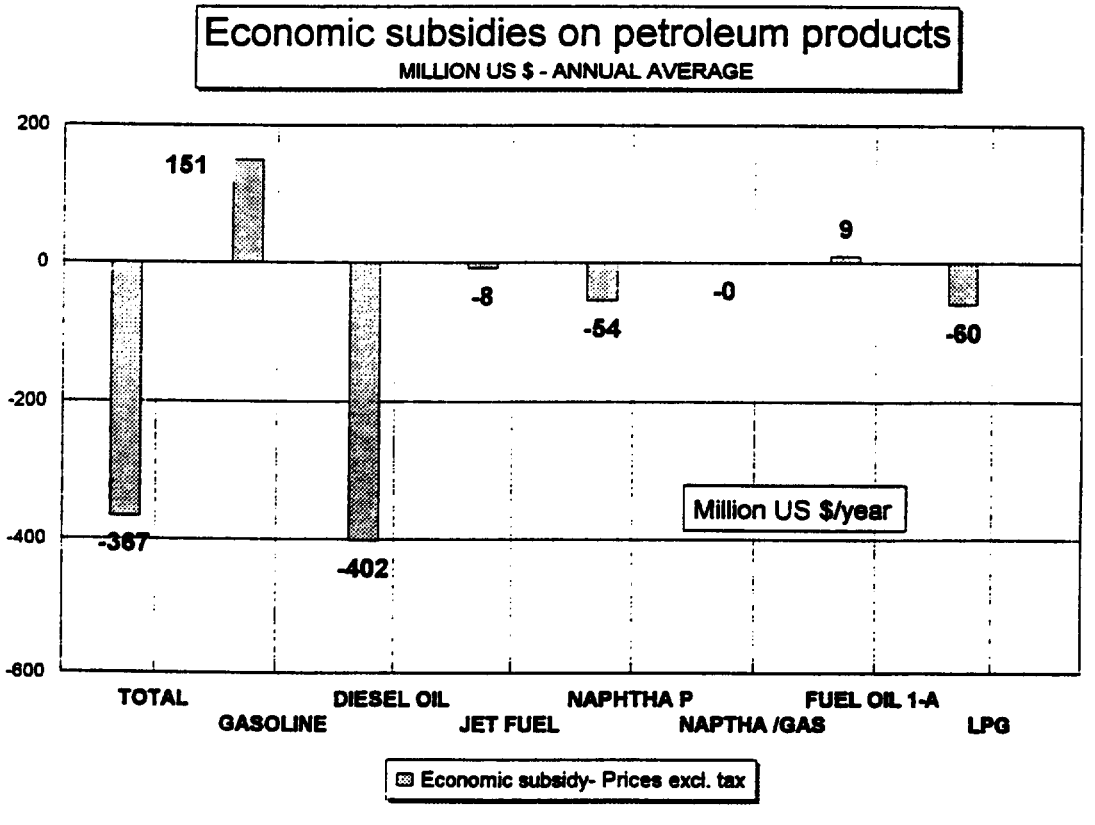
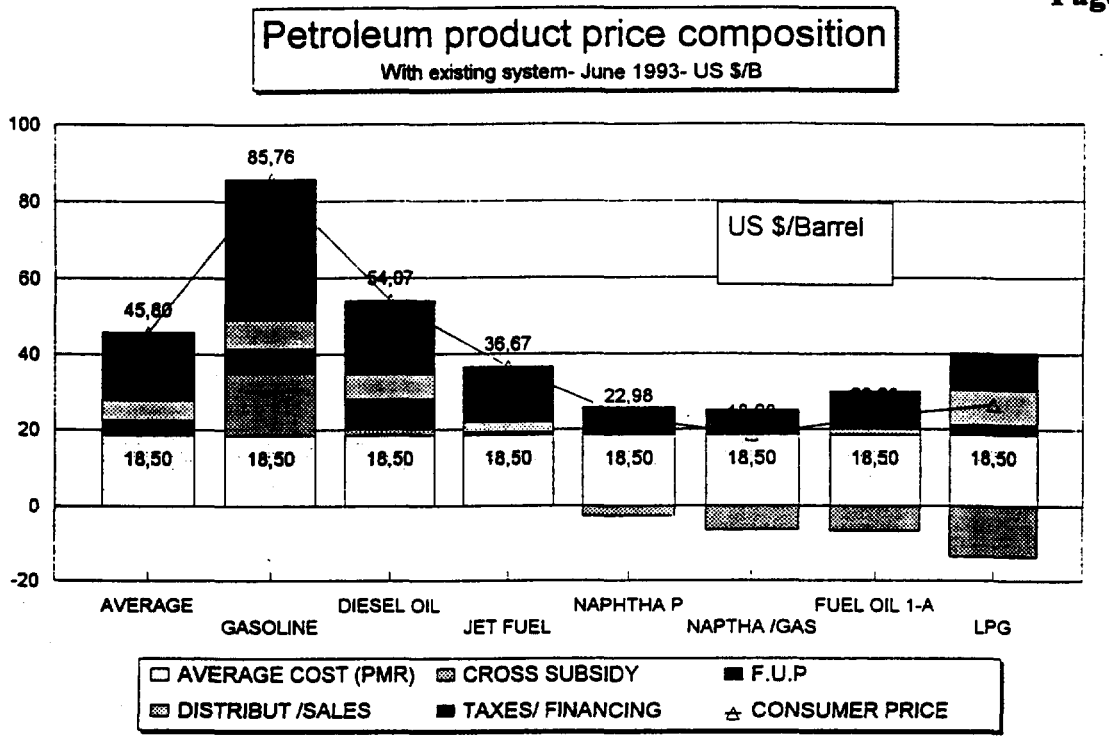
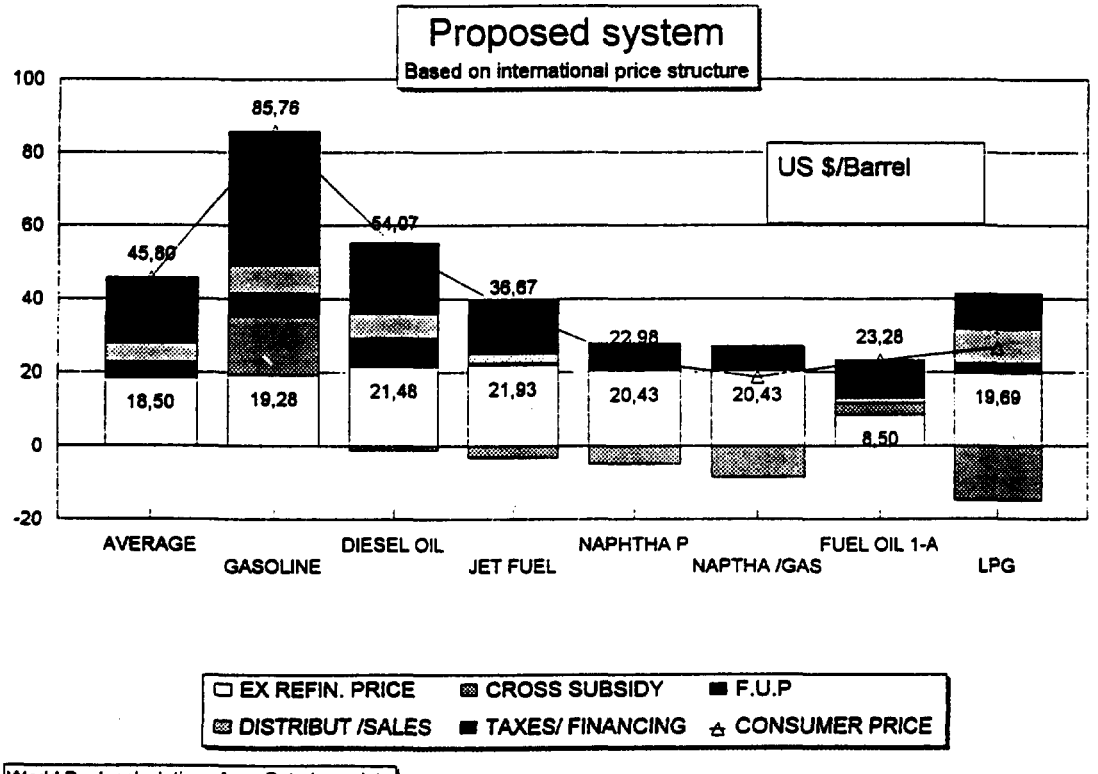

Economic subsidies on petroleum products
MILLION US $ - ANNUAL AVERAGE
200
0
-200
-400
-600
151
-367
-402
-8
-54
-0
9
-60
Million US $/year
TOTAL
GASOLINE
DIESEL OIL
JET FUEL
NAPHTHA P
NAPTHA /GAS
FUEL OIL 1-A
LPG
Economic subsidy- Prices excl. tax

Fig 3





World Bank calculations from Petrobras data

ANNEX 4.1

NATURAL GAS DISTRIBUTION COMPANIES IN BRAZIL

ANNEX 4.1

Natural Gas Distribution Companies in Brazil

ALAGOAS
Companhia de Gas do Estado de Alagoas - CEALGAS

BAHIA
Companhia de Gas da Bahia - BAHIAGAS

CEARA
Companhia Energetica do Ceara - COELCE

ESPIRITO SANTO
Secretaria de Desenvolvimento Economico do Espirito Santo

MATO GROSSO DO SUL
Empresa de Energia Electrica de Mato Grosso do Sul - ENERSUL

MINAS GERAIS
Companhia Energetica de Minas Gerais - CEMIG

PARANA
Companhia Paranense de Energia - COPEL

PARAIBA
Sociedade Anonima de Eletrificacao da Paraiba - SAELPA

PERNAMBUCO
Companhia Pernambucana de Gas - COPERGAS

RIO GRANDE DO NORTE
Companhia Energetica do Rio Grande do Norte - COSERN

RIO GRANDE DO SUL
Companhia de Gas do Estado do Rio Grande do Sul - SULGAS

RIO DE JANEIRO
Companhia Estadual de Gas do Rio de Janeiro - CEG

SANTA CATARINA
Centrais Eletricas de Santa Catarina - CELESC

SAO PAULO
Companhia de Gas de Sao Paulo - COMGAS

SERGIPE
Empresa Distribuidora de Energia em Sergipe S/A - ENERGIPE

ANNEX 4.2

FUNCTIONS OF THE NATIONAL SECRETARIATE OF ENERGY AND THE DNC

ANNEX 4.2

Functions of the National Sectratariate of Energy (MME)

(i) to formulate the national energy policy, to watch and coordinate its execution;

(ii) to oversee the activities related to matters of scope of the Federal Union in hydroelectric and related undertakings;

(iii) to supervise, control and surveil the utilization of hydro resources, and in general energy resources;

(iv) to promulgate norms on tariffs of power service;

(v) to promote and coordinate surveys, research and studies of hydro-resources, and in general energy resources;

(vi) to guide and surveil the activities related to the monopoly of the Federal Union, pertaining paragraphs I to IV of Article 177 of the Constitution.

Functions of the Departamento Nacional de Combustiveis (DNC)

(i) to guide and surveil the activities related to the monopoly of the Federal Union: (a) in the exploration and exploitation of deposits of petroleum and natural gas and other fluid hydrocarbons; (b) in the refining of domestic or imported petroleum; (c) in the import and export of the products and its derivatives resulting from the activities mentioned in (a) and (b); (d) in the maritime transportation of crude oil of domestic origin or of petroleum derivatives domestically produced, as well as transport, via pipelines, of crude oil and its derivatives, as well as natural gas of any origin;

(ii) to watch and surveil the execution of plans and activities by PETROBRAS, its subsidiaries and other companies which carry out the monopoly of hydrocarbons of the Federal Union;

(iii) to oversee, authorize, regulate, control and surveil the national supply of: (a) oil, schist oil and its corresponding derivatives; (b) natural gas and its recoverable fractions; (c) liquid carbureting fuels from renewable sources; (d) other carbureting fuels;

(iv) to watch, authorize, regulate, control and surveil the utilization of other fluid hydrocarbons.

(v) to watch, authorize and surveil the activities pertaining the supply of inputs to the piped-gas distributing companies.

(vi) to examine, authorize and surveil the localization, capacity, construction, expansion and changes of refineries and storage or transfer units, as well as the processing, characteristics and quality of the products;

(vii) to establish norms on the storage of the products referred at paragraphs (iii) and (iv) of this article;

(viii) to establish the specifications of the oil derivatives, as well as carbureting fuels;

ANNEX 4.2 (Continued)

(ix) to establish prices of oil and its derivatives, as well as other carbureting fuels, according to the guidelines established by the Executive Power for the prices and tariffs of energy products;

(x) to establish the percent of alcohol and other carbureting fuels to be used in the carbureting mixture by the distributing companies, establishing quotas and sites of delivery and mix;

(xi) to watch the national supply of mineral coal, its related and primary products, having the authority to supervise and surveil it through setting of prices, stock, quotas of production and distribution, consumption and import, as well as to issue norms on quality control and specifications;

(xii) to establish general norms of accounting that will be used by the companies which supply oil and its derivatives, as well a to scrutinize its accounts, inclusive of data that allow the exact determination of costs;

(xiii) to give opinion on the international agreements to be undertaken by the National Treasury, concerning the industry or trade of oil, its derivatives, fuel gas and other carbureting fuels;

(xiv) to establish and control the strategic stocks of oil and its derivatives, natural gas and other carbureting fuels;

(xv) to establish, for the purpose of compensation, the prices of freights of carbureting fuels and liquified oil gas;

ANNEX 4.3

INSTITUTIONAL ARRANGEMENTS AND REGULATORY MODELS IN OTHER COUNTRIES

INSTITUTIONAL ARRANGEMENTS AND REGULATORY MODELS IN OTHER COUNTRIES

Introduction

In North America and Europe virtually all countries have been reviewing their legal frameworks for gas production, transportation and distribution. Their aims differ widely but the trend is clear: to reduce the scope of monopoly and to induce gas companies to behave as if they were stimulated by a competitive environment. The instruments adopted include the removal of legal monopolies and exclusive rights, privatization, open access to pipeline networks, unbundling of services and the use of regulatory bodies to enforce these market-oriented policies. With the enactment of the Constitutional Amendment No. 9 (1995), Brazil has elected to join this trend and the body of international experience on gas regulatory issues may yield lessons. At the same time, three considerations should be kept in mind:

(i) there is no single model which might be applied to Brazil's gas sector, only lessons and cautionary advice in designing a Brazilian system;

(ii) Brazil faces the challenge to develop the gas regulatory framework from scratch which needs to be both market-oriented and which will attract the large investments required to design and build the natural gas infrastructure;

(iii) experiences of countries which have large state sectors will probably be the most relevant, such a France, Italy and Spain, and

The following is an overview of the main features of gas regulatory systems in Europe and North America. They are distinguished not by region but according to the element of state and market control found. While it was once accurate to say that the European countries were always more or less state organised, that is no longer the case, and the U.K. can more closely be classified with the USA and Canada.

The Market Models

1. Great Britain

The gas industry is subject to regulation by several statutes, the most important of which is the Gas Act 1986, which created for the purpose of regulation a body called the Office of Gas Supply (Ofgas). The industrial market is also subject to the competition law; in particular, the Fair Trading Act 1973, which has already been applied to the privatised gas business on two occasions in 1988 and 1992-93.

The dominant supplier of gas in the UK has been British Gas (BG), which has a statutory monopoly of the supply of gas by pipeline to premises whose consumption is not more than 2,500 therms a year and which are within 25 yards of BG's existing mains network. It is prohibited to supply gas without an authorisation granted by the Secretary of State after consultation with the Director of the Office of Gas Supply (Gas Act 1986, section 5), except for supplies to premises using more than two million therms a year.

The terms on which an authorisation is granted are set out in the Gas Act 1986, ss. 7 and 8. Authorisations may be granted by the Secretary of State after consultation with the Director General of Gas Supply or by the Director General with the consent of the Secretary of State. There are three types of public gas supplier: apart from BG, there are customers which own and operate their own systems within a defined geographical area and independent gas suppliers which use BG pipelines on a common carriage basis to supply customers consuming more than 25,000 therms of gas a year. A recent example of the latter category is Midlands Gas, a joint venture owned by Midlands Electricity and the US, electricity and gas utility, Utilicorp, which announced plans to offer gas to large consumers such as leisure centres and local government offices in competition with BG using BG pipelines on a common carrier basis in 1991.

Under the authorisation granted to BG on 28 June 1986, BG as public gas supplier is entitled to supply gas through pipes to any premises in Great Britain for a period of 25 years and thereafter until a notice to terminate it has been served by the Secretary of State on BG on a day at least 10 years before the notice is to take effect. No other company may supply gas without an authorisation even in exceptional circumstances.

The conditions of an authorisation can be modified without further legislation, permitting a degree of flexibility to cater for changing circumstances. Indeed, modifications have already been made to the original authorisation. For example, there are new conditions 5, 5A, 9 and 9A made to the original authorisation concerning, respectively, pricing for contract customers, use of gas or other forms of energy by contract customers, third party access and restriction of the use of information on third party access. All of these followed from a critical report by the competition investigative authority, the Monopolies and Mergers Commission in 1988. New condition 12A deals with methods of dealing with tariff customers in default and, as part of a tariff review completed in 1991 conditions 3,4 and 13A were revised, covering various aspects of the new formula. Condition 13A will require BG to publish details of its service commitment, delivery of service on an annual basis, its performance in these respects to be measured on annual basis against targets, details of a compensation scheme for poor service, setting out what the service commitment is and what compensation is to be paid for failure to perform. It will give Ofgas a policing power in this area. These modifications have been made by agreement.

There are several duties which an authorised public gas supplier must accept in the public interest. These include the duty to develop and maintain an efficient, coordinated and economical system of gas supply and to comply, in so far as it is economical to do so, with any reasonable request for him to give a supply of gas to any premises (the Gas Act, section 9). Under the Gas Act 1986, the obligations vary with respect to different classes of customers. The key distinction is between users whose premises consume more than 25,000 therms of gas in any period of twelve months and the rest called tariff customers. The latter include domestic, commercial and some industrial users, while the former include most industrial users.

A landing requirement (contained in the petroleum production licences necessary for offshore petroleum exploration and production) means that all licensees on the United Kingdom Continental Shelf must ensure that petroleum won and saved from the licensed area will be delivered onshore in the UK unless the Minister gives notice of his consent in writing to delivery elsewhere. This is in effect a ban on exports. On 6 March 1986 the Minister announced that BG would be able to import gas in future subject only to Ministerial consent and to the conclusion of any inter-governmental treaties, should these be required. BG then gave an assurance that it would

consult the government about its import plans as these developed. Waiver of the landing requirement on a case-by-case basis was also declared possible. In considering such applications, the government stated that it would take into account considerations relevant to the security of British gas supplies without any presumption against exports.

The owner of the transmission network is British Gas plc; therefore, no question arises about its access as a public gas supplier to the grid for distribution purposes. Any gas supplier may seek access to the pipeline network owned by BG by using section 19 of the Gas Act 1986 which permits third party access under specific conditions. The two provisos are that the gas is similar to the kind that the pipeline is designed to convey, and that such carriage would not prejudice the conveyance of gas by BG required to fulfil its obligations as a public gas supplier and its contractual obligations.

The system of open access set out in the Gas Act is a framework one, with potential third party users left to negotiate suitable terms with BG, within the framework of a detailed statement on common carriage which BG published subsequent to the MMC investigation. Failure to reach agreement on third party access means that the third party may apply to the Director General of Gas Supply. After considering the application and the views of BG, he may issue directions which stipulate the terms on which BG should allow gas to be conveyed by the third party when it has spare capacity as defined by the Director General.

Nevertheless, section 19 of the Gas Act and its subsequent interpretation shows that the powers of the Director General are very wide. He may direct BG to carry gas, may specify the terms on which a public gas supplier must make gas available to third party suppliers with third party access rights, may require that back-up facilities be provided as well as storage facilities and decide whether there should be an interruptible contract. Ofgas can draw up an entire common carriage regime, using powers of connection in individual cases. Indeed, in May 1989 it drafted a common carriage contract with a competitor supplier, Agas, to assist the Company in using its access rights and to encourage others to follow the Agas example by providing an assurance of Ofgas' willingness to assist competitors if difficulties arose on securing fair and reasonable terms from BG. In addition, BG is not at liberty to argue that there is a gas bottleneck as a defence against a request for carriage on behalf of a third party. Any terms of charge for carriage specified by the Director General must entitle the public gas supplier to recover the proportion of its costs and return on capital, which reflect the use made of its pipeline system.

As far as the relationship between the political authority and the regulatory agency is concerned, the Director General of Ofgas has responsibility for enforcing both the conditions of a public gas supplier's authorisation and the principal obligations imposed upon it directly by the Gas Act. Generally, the Secretary of State and the Director General each have a duty under section 4 of the Gas Act 1986 to carry out the functions assigned to them by the Gas Act in a manner which each considers best calculated to secure that a public gas suppliers satisfy all reasonable demands for gas in Great Britain so far as it is economical to do so and to secure that such persons are able to finance the provision of gas supply services. In practical terms, this is only of importance as far as BG is concerned.

The Gas Act 1986 establishes legal obligations for a public gas supplier with respect to different classes of customers. The key distinction is between users whose premises consume more than 25,000 therms of gas in any period of twelve months and the rest called tariff customers. The latter include domestic, commercial and some industrial users, while the former include most industrial users of gas. BG divides its contract customers into firm and interruptible consumers of gas. Interruptible gas sales as a percentage of total sales were 57% and 8% of the total sales in the industrial and commercial markets respectively in 1990. The distinctions drawn in the Gas Act between consumers above or below the consumption levels of 25,000 therms a year and 2,000,000 therms a year were lowered through the Utilities Act 1991. Domestic consumers fall into the former category.

The public gas supplier has an obligation to supply upon request any premises within 25 yards of a distribution main, subject to a maximum rate of 3,500 therms a year (section 10, Gas Act 1986, as amended). Codes of practice and relevant documents such as the Citizens' Charter must be followed. Specific safety requirements have to be met, as must prescribed standards of quality. It also has an obligation to supply gas in circumstances where it is economical to do so subject to a reasonable request to supply gas to any premises being made (section 9). The obligation is subject to two tests: economical and reasonable; ultimately, it is Ofgas that decides on both of these tests. A price formula applies in the tariff sector. In its original form, it was set out in Condition 3 of the Authorisation granted to a public gas supplier. It determines the maximum average price which BG can charge in the tariff sector. It has the following structure: RPI - X + Y - K.

Under the formula, BG can increase its prices up to the level allowed by the formula. The first part of the formula, RPI - X, where RPI means the increase in the retail price index, applies to "non-gas costs", that is, all BG's costs except the purchase cost of gas. BG is permitted to reflect increases in its prices up to the rate of inflation minus an efficiency factor (X) set at 2% for the first five years.

The second element in the formula, Y, concerned gas costs and permitted BG to pass through all its gas purchase costs into prices. Gas produced by BG is transferred at a price agreed with the Inland Revenue for taxation purposes, and permits the pass through of BG costs based on the rate of inflation less 2%. Prepayments under take or-pay arrangements are generally included in the gas costs component in the year in which delivery occurs. The third element, K, a correction factor, permitted under shoot or over-shoot in any particular year to be corrected in later years.

Introduced in 1986, a proposal to substantially amend it was accepted by BG in 1991 at the instigation of Ofgas. The new formula is more developed, containing a double price cap: one for non-gas costs, with a separate cap for gas costs, and a new efficiency element. It takes the following form: RPI - X + GPI - Z + E + K.

The first element, RPI - X, is unchanged from the previous formula, except that the X factor is increased to 5%. The Y element however has been replaced by a price cap, GPI Z, which permits BG to increase its gas costs in accordance with the movement in a special gas price index minus an efficiency factor, Z, set at 1%.

The second new element, E, will allow certain energy efficiency expenditure approved by Ofgas to be passed through. The K factor is the same as before, except that some of the limits have been tightened, making the amount that BG can over- or under-shoot more limited.

The new tariff formula is designed to ensure that BG performs efficiently and according to defined standards of service. The formula is tied to the standards of service offered by BG.

Finally, there are restrictions on the price which may be obtained by resale of gas. The Gas Act 1986 prevents anyone from selling gas supplied to them by BG from charging more than the maximum resale price fixed by the Director General of Gas Supply. Most commonly, this applies to landlords who buy gas from BG then resell it to tenants.

There are two bodies which are involved in consumer consultation: the Gas Consumers' Council (GCC) and Ofgas. Under sections 32 and 33 of the Gas Act 1986, the GCC has responsibilities for representing the gas consumers, the investigation of complaints and for giving advice. These may include, for example, problems concerning appliances inside customers' homes. It lacks legal powers to enforce remedies, except to refer the results of its investigations to Ofgas or the Office of Fair Trading (OFT). However, contract customers have not been reluctant to complain to the GCC nor has the GCC refrained from exercising its right of referral to Ofgas and the OFT. For example, it referred the matter of discriminatory pricing by BG for its contract customers to the OFT in November 1987, resulting ultimately in an investigation by the Monopolies and Mergers Commission. It also threatened to refer BG to the OFT in 1990 after an investigation into the price schedules introduced by BG for contract customers, which allegedly imposed substantially higher charges for gas on smaller customers such as local authorities and small businesses and at the same time reduced prices to larger customers. It has also been active in investigating and advising Ofgas about the tariff formula review.

The relationship between the distributor and the customer is supervised by Ofgas. The Director General is responsible for initiating modifications to the conditions of a public gas suppliers authorisation, which relate to the tariff market and for monitoring developments in the gas supply market.

Enforcement of the conditions of a public gas supplier's authorisation and particular statutory requirements is carried out by the Director General making a final or, in the appropriate case, a provisional order. He may make an order if satisfied that there is a continuing contravention in a condition or requirement or that the supplier has contravened and is likely again to contravene the condition or requirement. Before making an order the Director General must publish his intention to do so and invite and consider representations and objections (Gas Act, section 29). If any order is ultimately issued, the public gas supplier may appeal to the court within 42 days solely on the grounds that the Director General exceeded his powers or that he did not comply with a procedural requirement. There is no criminal sanction for contravention of an order but it does give rise to an action for damages by any person affected by the contravention.

For contract customers seeking interruptible supplies, the terms of the Authorisation were revised in 1989 to include a requirement that BG meet all requests for interruptible supplies of gas, as far as is reasonably possible.

There are three different Schedules of standard prices and terms offered to BG customers in the contract market. Firstly, BG published a Schedule of Prices and Terms for the Supply of Gas to Firm and Interruptible Contract Customers on 1 November 1990 (FI4). Secondly, there is a Schedule of Prices and Terms for the Supply of Gas on a Medium Term (3 to 10 year) basis to Firm and Interruptible Contract Customers (MT2), effective from 1 November 1990. Thirdly, there is a Schedule of Prices and Terms for the Supply of Gas on an Interruptible Basis to Contract Customers (LTI2). This refers to a contract period of not less than 10 years nor more than 15 years on a contract expiring no later than 30 September 2010 and to a nominated gas consumption of not less than 50 million therms per annum at each premises. Customers may choose alternatives to the standard contract terms by selecting optional terms. The Schedules may be withdrawn on giving 28 days notice unless the consent of the Director General of Gas Supply has been obtained to do otherwise.

In contrast to the tariff market, the justification for a government role in the contract market is weaker. The aim of government has been to ensure price transparency, by compelling BG to issue price schedules of maximum prices for gas supplied in the contract sector.

The Director General of Gas Supply has no powers to prevent price increases to contract customers. The actual prices set are purely a matter for BG. The conditions on which Ofgas may become involved in pricing matters were set out in the new Condition 5 of the authorisation, adopted effective from 1 May 1989. According to its provisions, BG is to supply to the Director prices to be charged which it proposes from time to time for different classes or descriptions of contract customers. These have also to be published in such a manner as will secure adequate publicity for them. A major concern here has been to ensure that BG does not discriminate between one class of customer and another. BG is obliged under the Condition to fix such prices or other terms so that, as far as is reasonably practical, all requests to give interruptible supplies of gas to premises on those prices or other terms on those prices or other terms which may reasonably be expected from persons wishing to become contract customers in respect of such supplies. BG is not to alter these prices for any particular class or description of contract customer more than once in any period of 28 days without the consent of the Director. BG as public gas supplier is expressly precluded from taking into account matters other than those relating to the supply of gas to a particular class or description of contract customer when determining the different classes or description of contract customer. No change may be made to classes and descriptions of contract customer approved by the Director of Gas Supply unless BG has first given the Director 21 days' notice of his intention to make the change and the Director has given notice to BG within that period that, on the grounds specified in the notice, the change would contravene the provisions of the Condition.

However, the Director General of Gas Supply does have powers to order BG to act in compliance with the terms of the Gas Act if he believes these have been breached and are likely to be breached again. In particular, he may act if BG appears not to be carrying out his duty according to section 9(1)(b) of the Gas Act to comply with any reasonable request for BG as public gas supplier to give a supply of gas to any premises. On 1 March 1991, for example, Orders were issued because the Director General believed that BG's decision to raise prices for gas supplied to power stations by 35% was tantamount to a refusal to meet reasonable requests for a supply of gas. He is empowered to do so if he considers BG is acting in contravention of section 9(1)(b) of the Gas Act "to comply so far as it is economical to do so with any reasonable request to give a supply of gas to any premises". The Company has the right to challenge the Orders in the High Court.

The relationship between the distributor and the customer is supervised by Ofgas and the Gas Consumers' Council (GCC). In addition, the public gas suppliers are subject to the competition law. These are the Fair Trading Act 1973, the Restrictive Practices Act 1976 and the Competition Act 1980.

According to the Fair Trading Act 1973, the Director General of Fair Trading may under sections 47 (1), 49(1) and 50 (1), refer to the Monopolies and Mergers Commission the matter of the existence or the possible existence of a monopoly situation in relation to the supply of gas through pipes in Great Britain to persons other than tariff customers within the meaning of Part 1 of the Gas Act. Such an investigation has in fact been made twice, firstly in 1987 following complaints from some contract customers about the pricing policy of BG and secondly in 1992 at the initiative of both the regulator and the government. The recommendations of the first MMC inquiry were largely implemented by means of modifying the authorization of BG. However, other recommendations were implemented through the Fair Trading Act which permits the Secretary of State for Trade and Industry to seek appropriate undertakings from BG.

The Director General may under section 28 of the Gas Act 1986 issue Orders for securing compliance with provisions of the legislation or authorisation which in his view have been contravened by the public gas supplier. Failure to comply could lead to revocation of the authorisation by the Secretary of State, according to Schedule 2 of the authorisation or to legal action in the courts involving penalties, compensation or imprisonment. The main penalty for failure to comply with Orders under section 28 is that such a failure creates a right to damages on behalf of the aggrieved party.

Similarly, there are penalties imposed for non-compliance with the competition law. Revocation of the authorisation may follow if the supplier fails to comply with any order made by the Secretary of State. Revocation of the authorisation may also follow from the non-payment of fees to the Secretary of State, under the terms of Condition 16 of the authorisation.

Recent Events

In 1994, the gas trading function of British Gas was separated from the gas transport function, and BG's share of the contract market has declined from 100% in 1986 to about 40%. Currently, there are about thirty companies licensed to supply gas in the U.K. These include the oil majors such as Texaco and Shell, and BP.

In 1995. a bill was published to amend the 1986 Gas Act. The intention is to introduce competition into the domestic market between 1986-1988. It also proposes a three tier licence to cover transportation, supply and shipping. The transportation licence will authorise the holder to transport gas through pipes to any premises in the authorised area, or to the pipeline system of another transportation licence holder. The licence holder will have exclusive rights to transport gas to consumers with a consumption rate of up to 75,000 therms per year within the concession area, but are obligated to connect such consumers to the pipeline if located within 23 meters of one of their distribution mains. The holder of a transportation licence is not allowed to hold a gas supplier or gas shipper licence.

A gas supply licence will allow the licencee to supply gas to premises, and it is intended that holders of supply licences should compete withe each other for the supply to consumers. A gas supply licence can be issued for supply of gas at more than 2,500 therms per year, which covers commercial and industrial customers. For gas supply below 2,500 therms per year and which covers domestic users, there are obligations to supply consumers which may include disadvantaged groups such as pensioners.

A shipper licence would allow the holder to arrange with a public gas transporter to transport gas through his pipeline system, and some gas suppliers will also hold gas shipper licences.

With the emergence of gas to gas competition and the development of a spot price market, the long term take or pay gas supply contracts entered into by BG have been severely undermined by the sall in the market prices, and the issue has arisen whether these contracts will be honoured. It is noted that the dynamic in the British system is strong government support for the promotion of competition in the industrial sector and increasingly in the small consumer market. After successive reviews of the workings of the system, the regulator's powers have been increased. The disadvantages are limited accountability by the regulator and the risk that regulator will take action against the interests of the shareholders in the privatised gas industry. The advantages are lack of bureaucracy with only a small regulatory body, acting within the framework of legislation and responsible to the Minister, with budget to include funds for consultancy work since outside expertise will be required from time to time. It is also not overly legalistic. There is no regulatory capture by their industries and there are incentives for efficiency. The system of price regulation has so far led to a significant fall in the price of gas to small consumers.

2. The United States

The structure of the US gas market is unique in terms of the numbers of companies in each of the different components of the gas chain. It is almost like a collection of several different gas markets. At the production level, there are tens of thousands of producers but only 24 have reserves of more than 25 BCM. Gas is transported through 23 major and 55 minor interstate pipeline systems and distributed by about 1600 distribution companies.

In the US there has been a tradition of heavy regulation of the gas industry dating back to before the 1920s. Controls have been imposed at both the State and Federal levels and cover a wide range of the industry's activities. At the Federal level the Federal Energy Regulatory Agency (FERC) has a quasi-legislative role and controls inter alia well-head prices for gas (where not already deregulated), as well as the prices and other terms of sale from transmission companies to distribution companies, the marketing policies and price setting rules for gas sales by distribution companies to consumers and the building of interstate pipelines by transmission companies. The State regulatory agencies, usually called Public Utility Commissions or Public Service Commissions, have in general controls over the licensing and continuing obligations of the distribution companies, the pricing and marketing policies of those companies (within the framework set by the FERC) and the building of pipelines within the US. The controls exercised by the bodies at both Federal and State levels are usually positive rather than negative. That is to say, the utilities can only act once the Commissions have given explicit approval for the course of action. Decisions by the Commissions are subject to review by the courts and can be subject to extensive litigation.

The detailed operation of the regulatory system at State level varies from authority to authority but generally it involves the submission by a gas utility of a written case for a price increase which is then subject to an examination and presentation of other evidence and often pronounces on allowable costs and assets in agreeing to new prices. If the agency is not able to give a final decision within a certain time the utility is normally allowed to charge the new rates but is required to keep the extra revenue in a trustee account.

The legal framework for the gas industry, always complex, has been reorganised in recent years through various measures which are usually described as deregulation. This began with the Natural Gas Policy Act (NGPA) of 1978 which initiated a process of price decontrol at the well-head, but accelerated considerably with the introduction of FERC Order 436 in 1985. Its primary goal was the establishment of a so-called voluntary program by which interstate pipelines would make available to all comers, on a first-come/first-served basis, transportation capacity for customer-owned natural gas.

Order 436 promulgated new regulations for:
1. the grant of blanket authorization for nondiscriminatory interstate gas transportation services,
2. the establishment of expedited certificate procedures for new transportation services, and
3. the elimination of the proposed "safe harbour" presumption for take-or-pay buy-outs in favour of merely retaining its existing "Statement of Policy and Interpretive Rule" concerning such buy-outs.

Order no.436 expressly recognized the emerging "unbundling" of the natural gas industry into commodity and transportation components. The FERC adopted as its overriding goal the restructuring of natural gas regulation in a way that would retain utility-type regulation over the interstate transportation function, in which monopoly power existed, while allowing the commodity market for natural gas to develop in what the FERC perceived to be a competitive manner. Order no. 436 contained five central elements:

1. in order to take advantage of blanket certification a pipeline had to commit itself to provide transportation on a non-discriminatory, "open-access" basis,

2. if demand exceeded capacity for open-access transportation, capacity had to be allocated on a "first-come, first-served basis",

3. the order provided that maximum and minimum transportation rates on open-access pipelines would be set by the Commission, leaving the pipeline free to adjust rates within this allowable range,

4. open-access pipelines had to permit LDC customers to reduce their contract demand (CD) or convert it from an obligation to purchase gas to a right to equivalent volumes of transportation,

5. the order provided for optional expedited certificates for new facilities, services, and operations, where the pipeline undertook the economic risk of the project.

Like all FERC Orders, it could be and was challenged in the Courts. The FERC was attempting to deal with the difference in prices available in the spot-market relative to prices available under long-term gas purchase contracts entered into by the interstate pipelines with producer/suppliers. The FERC enacted, as its initial solution, Special Marketing Programs (SMP). These programs generally allowed an interstate pipeline to release volumes of high-cost gas under its contracts with producers to resell the gas to certain industrial customers at a lower price competitive with alternate fuels. In return, the interstate pipeline was relieved of its take-or-pay obligation for all gas that was released and resold.

The SMP program was severely criticized by industrial customers who were aware of the considerably lower-cost gas supplies available on the spot-market, but who, for various reasons, could not purchase spot gas because they were unable to gain access to pipeline capacity to transport the cheaper gas. The SMP's were also criticized by commercial and residential customers.

Order no.436 was intended to allow access to transportation by industrial customers as well as residential and commercial customers. The Order specifies certain terms and conditions under which an interstate pipeline or an intrastate pipeline may transport gas under section 311 of the NGPA and it applies the same terms and conditions to special blanket section 7(c) certificates, which Order No. 436 authorizes the FERC to issue to interstate pipelines. Under blanket transportation certificates, interstate pipelines may transport gas on behalf of any person including end-users. Once prior approval of the blanket certificate is issued under section 7(c) of the NGA, no further prior approval is required for the pipeline to commence each new transaction requested by individual end-users, subject of course to the specific provisions required by Order no. 436.

The process of deregulation was taken further by Order 451 which raised gas prices. Order 500, made in 1987, presented a comprehensive approach to the take-or-pay problems in response to a Supreme Court decision. In the long-term all costs for gas as a commodity are to be known to the purchaser who can then make purchasing decisions through free nominations. Most recently, the FERC approved Order 636 or the Restructuring Rule. This is intended to complete the transition to a decontrolled natural gas transportation market. The aim is to ensure that pipelines provide equal transportation service for all gas supplies, whether the customer buys the gas from the pipeline or from another supplier. It should improve access of gas

buyers to a wide variety of gas sellers so as to maximise the benefits of the competitive wellhead gas market.

Among the principal elements included are:

1. Interstate pipelines are required to provide transportation unbundled from their sales of gas;

2. Blanket sales for re-sales certificates are to be issued authorising interstate pipleines to sell gas on a basis similar to unregulated sellers at market-based rates on compliance with the Rule. Existing sales certificates are to be converted into new blanket certificates. The pipelines, as gas merchants, will be subject to standards of conduct and reporting requirements which currently apply to their marketing affiliates under Order No.497. Existing pipeline customers are to be given an opportunity during a transitional period to reduce or terminate their purchases from the pipeline in order to switch to another gas seller.

3. Pipelines are required to provide open access transportation services on a basis which is equal in quality for all gas supplies whether purchased from the pipeline or another seller. Pipelines are prohibited from including any tariff provision which would inhibit the development of market centres. Market centres are defined as areas in which gas purchases and sales occur at the intersection of different pipelines. In additiion, the Rule requires a pipeline to provide all shippers with equal and timely access to information by mandating the use of an electronic bulletin board.

4. The definition of transportation is extended to include storage so that pipelines must provide customers with open access to storage on a contract basis.

5. Policies are established for the recovery of transition costs incurred by pipelines in complying with the rule. Pipelines will be permitted to direct bill any unrecovered balances in their purchased gas accounts upon

converting to market-based pricing for sales. Pipelines are encouraged to assign their existing gas supply contracts to their sales customers to minimise transaction costs. they will also be entitled to recover 100% of the prudently incurred costs for realigning their gas supply contracts as a result of implementing the new Rule. Gas supply realignment costs may be recovered through a surcharge on firm transportation reservation fees.

6. Procedures are specified to be used and filings to be made by pipelines to comply with the Rule. In a companion notice to the Rule the FERC has established a proceedings (with an RS docket fix) for each pipeline which must comply with the Rule. Each pipeline is assigned a date in the Rule by which it must make its compliance filing. All pipelines are expected to be in full compliance with the Rule for the 1993-94 winter heating season.

The high profile role of the FERC should not obscure the role of the American courts in the gas sector through the anti-trust legislation. This has focussed in recent years on the "essential facilities" doctrine, that a refusal to allow access to essential facilities may amount to an abuse of market power. This doctrine has evolved as a means of determining whether an entity has monopoly or market power for the purposes of the offence of monopolisation under section 2 of the Sherman Act, under which it is an offence to "monopolise or attempt to monopolise, to combine or conspire ... to monopolise" trade or commerce. Instead of adopting the usual approach of analysing market share, the doctrine permits a focus on the nature of the facility and the monopoly power it yields. It applies "if duplication of the facility would not be economically feasible and if denial of its use inflicts a severe handicap on potential market entrants".

The test can be broken into four elements:

i) Control of the essential facility by a monopolist;
ii) A competitor's inability practically or reasonably to duplicate the essential facility;
iii) The denial of the use of the facility to a competitor, and
iv) The feasibility of providing the facility.

The doctrine has been developed both by the anti-trust authorities and the FERC to introduce competition in transmission and to mandate access. However, the obligation to grant access to an essential facility is far from absolute. There have been difficulties in defining whether it is "economically feasible " to duplicate the facility and whether access is "feasible". The difficulties suggest that an analysis of efforts to monopolise vertically integrated markets has to be more complex than the typical analysis of concentration in a single market, where conventional market share tests might be applied.

Summary

Over the past decade there has been intensive deregulation aimed at bringing about gas-to-gs competition and creating a substantial spot market. The advantages of this system have been lower consumer prices and greater choice. It may also be noted that the interstate pipeline operators have been under pressure to withdraw from the sale of gas to end users (like British Gas). Competition ot supply gas to end users is generally confined to the largest industrial and commercial customers. Most trading and distribution activities within each state have remained under integrated ownership. The disadvantages are well-known: the system encourages litigation, has a complex and legalistic character and has a large and bureaucratic regulatory agency.

3. Canada

The structure of the gas industry in Canada bears a resemblance to that found in Europe: there is one pipeline carrier for interprovincial transport of gas, from the producing states of the west to the markets of the east. There are several intra-State pipelines and about seven hundred gas producers but all are in the west of the country. Between one third and a half of this production is exported to the USA. In the 1980s deregulation began, similar to the US experience, with the pipeline carrier being compelled to provide access to the network; distribution companies and industrial users were allowed to purchase gas directly and lower prices resulted.

The Constitution of Canada assigns power over natural resources to the federal parliament and to the legislatures of the provinces. Parliament may declare any Act of any provincial legislature inoperative. The National Enterprise Board (NEB) regulates the export of gas from Canada and regulates in detail the tolls and tariffs and the construction of pipeline facilities which are regarded as major systems having a monopoly position and being of vital importance to producers and consumers. The principal federal and provincial agencies (in Canada as a whole, Alberta, Ontario and Manitoba) are responsible for the resource's stewardship.

The NEB was created by Canadian Parliament in 1959 with the passing of the National Energy Board Act. The Board's jurisdiction under the NEB Act with respect to natural gas is restricted to export and import approvals, facilities certification, export pricing, traffic, toll, and tariff regulation. Its jurisdiction with respect to domestic gas pricing is found in the Energy Administration Act. A major impetus to its creation was the decision by the federal government to promote the construction of an all-Canadian natural gas trunk pipeline from Alberta to central Canadian markets.

Under the NEB Act, certain advisory functions were ascribed to the Board. It is to make continuous studies and reports on Canadian energy resources to the Minister of Energy, Mines and Resources. It has adjudicatory functions which cover the following matters:

i). Approval of the NEB is required for the construction and operation of international or interprovincial oil and gas pipelines and electric power lines;
ii). Approval of the NEB is required for sales, amalgamation or abandonment of commercial pipelines, limiting transactions in this area;
iii). The procedure for the expropriation of pipeline rights of way.
iv). In the area of rate regulation, approval is required for extra provincial pipeline rates, tariffs and tolls. All tolls are required to be just and reasonable and the NEB may disallow rates and prescribe other rates instead.

These functions are facilitated by the NEB's ability to make its own rules of practice and procedure. With the approval of the Governor in Council, it may use its delegated powers to make pipeline safety rules and compel the production of books of account. All NEB decisions are final and conclusive except for a limited appeal which lies to the Federal Court of Appeal on a question of law or a question of jurisdiction. The NEB has an influence in policy development separate from the policy directives that it inherits through the Act. It has a quasi-judicial function in the award of licences. Licences must be issued under the NEB's authority in order to export gas from or import it to Canada.

During the past few years, the NEB has spent increasing amounts of time on matters relating to pipeline jurisdiction. The cases coming before it have ranged from jurisdiction over proposed offshore installations to jurisdiction over storage and distribution facilities in Central Canada and to jurisdiction over gathering and feeder lines in the West. There can be little doubt that this spate of jurisdictional issues has been generated by several processes such as deregulation, the open access system and the ratification of the Free Trade Agreement with the United States. The Board currently regulates about 28,000 kilometres of oil and gas pipelines, operated by 40 separate companies. Its jurisdiction over pipeline facilities is most commonly triggered by applications under Part 3 of the NEB Act for authorisation to construct and operate pipeline facilities which will cross a provincial or an international boundary.

Jurisdictional matters are less clear than in the USA. In contrast to the USA, Canada has no broad Federal Constitutional power over trade and commerce. Though there have been some recent developments, Canadian doctrine gives provinces exclusive power to regulate particular business or trade. The NEB's power is based principally on jurisdiction over interprovincial facilities and not regulation of trade and commerce. There is a lack of clarity over the limits to the competence of the provincial tribunals which originates from the

constitutional apportionment of legislative power in the federal state. Despite court hearings on these matters, key questions such as whether major pipeline systems in provinces (e.g. NOVA in Alberta) connected to interprovincial pipelines (TCPL) are legally part of the interprovincial pipeline and subject to Federal regulation have never been decided.

At the Provincial level, the Alberta Energy Resources Conservation Board (AERCB), originally created in 1938, is the principal agency. Its powers have been progressively reformed and broadened over the years. Another body, engaged in rate-making for natural gas which is transported and sold, is the Public Utilities Board. By statute, the AERCB is given authority to make just and reasonable orders and directions to promote those purposes (economic, orderly and efficient development in the public interest of oil and gas in addition to the prevention of waste) of the Act which are not specifically stated. To facilitate this task, the ERCB is endowed with wide investigatory and advisory powers on petroleum related matters. The Board assists the formulation of government policy with the acquisition and dissemination of technical information with a view to determining supply and demand of the resources under its stewardship. From both a provincial and a national perspective, one of the key functions of the ERCB is its control over the export of Alberta gas, also a matter of constitutional dispute. There have been no determinations. In order to export gas, a removal permit may be obtained from the Board following an inquiry into all applications.

It may seem as if Alberta has comprehensive regulatory control of the downstream disposition of its natural gas resources, but in the case of east-bound gas, the ramifications of this control may eventually flow to the consumer via the TCPL main-line, and subsequently by local distribution companies.

The Ontario Energy Board (OEB) and the Manitoba Public Utilities Board (PUB) regulate the domestic market in each respective jurisdiction, particularly setting tariffs and tolls for provincial consumers. The OEB is the principal energy regulatory and advisory tribunal having jurisdiction over pipelines as well as the power to make orders approving or fixing just and reasonable rates and other charges for the sale of gas by transmitters, distributors and storage companies, and for the transmission, distribution and storage of gas. Similarly, the Manitoba PUB has jurisdiction over intra-provincial pipelines and the authority to fix just and reasonable rates, tolls or schedules which must be followed by a public utility.

As a matter of fact, all three gas producing provinces have a more or less equal system, consisting of an Energy Board and a Public Utilities Board.

4. Germany

The unification of Germany has entailed a process of privatisation and commercialisation of the state-owned gas industry in the Eastern territories. The analysis of the regulatory structure can therefore be divided into two parts, focussing on the legal structure of the established gas industry which is largely in private ownership and the legal processes involved in absorbing the gas industry of former East Germany.

Currently, some gas is produced domestically by companies such as Mobil, Wintershall and Brigitta und Elwerath (BEB) but the largest proportion of gas consumed is imported. There are more than thirty owners of pipelines but only a half of them could be considered significant and of these the most important is Ruhrgas. Ownership is complex but includes large shares by international oil companies. Gas is distributed by more than 500 companies which are in public, private and mixed ownership. In the east, the principal gas transmission company was Verbundnetz Gas (VNG), which imports gas from Russia and competes against Wintershall Erdgas Handelshaus (WIEH), a joint venture between Wintershall and Gasprom.

Competence in regulatory matters is shared between the Federal and the State authorities. The established structure of regulation requires a minimal role for them, in principle leaving as much as possible to market forces. The relevant legislation comprises both energy legislation and competition law. The latter is largely directed at preventing abuses of competition through the Competition Act (Kartellgesetz). Recent amendments to that legislation have attempted to stimulate competition but the results have been very modest. There is a trend, however, for the Federal Competition Office (Bundeskartellamt) to become more active in monitoring abuses of dominant power in the market. At the State level, there are also competition offices.

The other piece of central legislation is the Energy Act (Energiewirtschaftsgesetz) which dates from 1935 and is a much less complex instrument. Its objectives are to provide for a secure energy supply and to do so at a low cost.

For many years the legislators have been willing to tolerate agreements between energy companies to divide the country into closed regions, in which no competition exists. This is an exception to the general legislation against monopoly practices. Two kinds of agreements are therefore not subject to the competition law: concession agreements between the municipalities and the energy supply companies, and demarcation agreements between the energy supply companies. In a concession agreement a municipality grants an energy company an exclusive right to use the areas for networks, while the demarcation agreement permits energy companies to divide territory among themselves, undertaking not to compete with each other. To avoid abuse of this lack of competition, an extensive system of controls has been set up. Particularly important is the obligation of supply companies to connect and to supply each client in the closed areas at published tariffs.

In all stages of energy supply there are different forms of control. A permit is required to start an energy supply company and all new investments have to be announced or notified. A company has to fulfill its tasks or it can be closed down.

There is a provision concerning third party access in the competition law. A refusal to conclude agreements on reasonable terms with other companies with respect to the transport of energy is considered unfair. In assessing the unfair conduct, the effect of the transmission on the market conditions is to be taken into account, especially the conditions of supply for the purchasers from the public utility committed to such a carriage. Previously, a refusal to transmit was not treated as unfair if the transmission would result in supply to a third party in the area served by the public utility. This has been dropped, strengthening the provision by removing an exception to abuse practices.

The first decision in which the Competition Office has found evidence of an abusive practice when third party access was refused occurred on 29 June 1992, and has since been the subject of appeals.

In the event of an abuse, the responsible competition authorities may issue an administrative injunction requiring an abuse to cease or requiring a change in the agreement. The strictest form of sanction is to declare the agreement void. Recent developments have tended to promote competition. For example, a maximum period has been set for the duration of demarcation and concession agreements. They can run their course to a length of 20 years.

German legislation draws a distinction between tariff customers and non-tariff customers: roughly a division between domestic and non-domestic customers. Under the Federal Tariff Regulations for Gas of February 1959,

distribution companies are obliged to publish at least two tariffs to domestic customers (i.e. small consumers only):

- A Small Consumer Tariff, consisting of an obligatory meter charge and a commodity charge. In general the annual consumption is under 1200 cubic metres. The consumer is offered a general supply contract.

- A Basic Tariff, including a standing and a commodity charge valid for all users and all types of customers. The tariff may not exceed 60% of the commodity charge in the Small Consumer Tariff. These customers are not offered a completely standardized contract, though some are offered rather similar contract terms. Therefore they are referred to as `normalized' customers.

In practice most distribution companies offer at least three tariffs to domestic consumers, whereby the first two would apply to natural gas used for cooking and/or hot water as the third would be more suitable for central heating.

The distribution companies can decide their own tariffs within the framework of the aforesaid "Bundestarifordnung Gas". Because of the large municipal shareholdings, indirect government influence is present. In cases where the distribution company is a municipality, the tariffs have to be approved by the municipality. The Federal Minister of Economic Affairs has the competence to regulate the general supply conditions for tariff customers of the gas distribution companies. The Regional Ministers of Economic Affairs supervise the prices.

The general pricing principle is that of market-valued price for each customer, with the distribution company setting the gas price according to the next closest fuel alternative. Since the enactment of the Federal Tariff Regulations for Gas, the distribution companies have been free to change the prices (no price-stop).

There is no legal obligation providing for consumer consultation on prices and conditions of supply. Nevertheless, consumer organisations do hold regular discussions with the associations of gas suppliers in Germany on the subject of general terms and conditions of gas supply. They do not deal with specific complaints.

The formerly state-owned gas companies in the Eastern territories were privatised by the Treuhandanstalt or Government Trustee Agency. The result was an enhanced role for Ruhrgas and Wintershall and the entry of the Russian gas concern, Gasprom, into the market as a shareholder in VNG and WIEH. The shares of the companies engaged in the regional gas supply business have also been privatised. A 50% share was reserved for local authorities in the eastern territories. The other purchasers of these companies are largely West German transmission and distribution companies, some of which already hold an nterest in municipal supply companies. Some foreign companies have also acquired minor stakes however.

The privatisation of the regional gas and electricity supply companies was carried out separately. Formerly, in East Germany, gas and electricity were distributed jointly by energy distribution companies. In future, as in the rest of the country, they are to be marketed separately. To this end regional gas supply companies have been established.

5. Australia

Australia is a federal system with regulatory competence split between the Federal and State levels. The country has three interstate pipelines and a potential for several interstate connections. A Code of Conduct has been introduced for negotiating access to interstate gas transmission pipelines by gas producers seeking to deliver gas into markets remote from the fields. The Code was developed by the three industry associations together with state and federal governments, and the Trade Practices Commission. The result will be to make the pipeline industry self-regulating. It provides a mechanism for potential gas suppliers to negotiate access on commercial terms to large gas pipelines which cross state borders. The Code includes general pricing principles, guidelines on information exchange and aims at the promotion of non-discrimination and transparency in further use of gas pipelines. An independent mechanism is set up for dispute settlement. One of the benefits sought by gas producers by this arrangement was access to existing and future pipelines by providing greater certainty that pipeline capacity would be made available at a known price.

The State Models

1. France

A small percentage of gas demand is met by domestic production carried on by Elf, a company in mixed ownership. For the most part transportation and distribution is carried on by the state-owned monopoly, Gaz de France (GdF) and supervision of the gas industry is carried out by the Ministry of Industry.

The dominant company in gas transmission and distribution is GdF, created on the nationalisation of gas and electricity sectors by the Loi No. 46 628 of 8 April 1946 Sur La Nationalisation De L'Electricité Et Du Gaz (NEG Act). Article 3 of the NEG Act entrusts the operation of the nationalised gas services to GdF. The combined effect of the nationalisation provision (Article 1) and the `trust' provision (Article 3) in the NEG Act is granted to GdF, subject to some statutory exceptions, a legal monopoly for the supply of natural gas in addition to its distribution. The NEG Act allowed GdF to take over the concessions held by private parties and also granted GdF the franchise for all the communes with some exceptions.

It should be noted that the same law gave public enterprises a "mission de service public" which can be summarised as requiring that any customer without discrimination should have the cheapest supply compatible with the strategic economic and industrial orientations laid down by the Government. The aim of profit maximisation was replaced by the aim of 'optimum social' and state owned enterprises were required to appear as a 'model social' for the management of human resources. The French Government takes the view that the monopoly is an essential condition for meeting the requests for gas supply and that this is compatible with the exemptions under the Treaty of Rome (Article 90.2). This recognises that undertakings entrusted with the operation of services of a general economic interest are subject to the Treaty rules only insofar as those rules do not obstruct the performance of the tasks entrusted to them. The import monopoly is essential to the performance of GdF's obligations under the 1946 Act. Abolition of the monopoly would lead in the Government's view to an increase in prices, to discrimination between large and small users and to a loss of supply security.

In general, the public distribution of gas is according to the NEG Act a public service aimed at the improvement of domestic and business consumers, especially specific industries whose consumption of gas is compatible with the capacity of the pipelines.

There are no legal limitations on the activities of companies in the distribution sector. It may be noted, however, that the distribution of gas is regarded as a public service. There are several means of carrying out the public gas distribution service. There is a droit commun and several special legal regimes. With respect to the first, the legal device used is the concession. This is a contract through which the State or a local authority permits a public or a private person to set up operations and run a public service at its own risk and expense. Two documents are required: a convention and a schedule of charges annexed to the convention. The latter determines the rights and obligations of the conceding authority and the concessionaire. The concession is given on a zonal basis, extending over a specific geographical area, the territory of a commune or several communes. An alternative to this is the use of the municipality (régie) as a basis for exploitation of the public gas service. A public entity carries out distribution on a local basis so as to assure distribution at its own risk and peril, principally with its own staff and at its responsibility. There are many types of régies in existence.

Imports of gas are a legal monopoly of GDF under the NEG Act. According to Article 1(2) of the NEG Act, its scope extends over the import and export of fuel gas and according to Article 3 the management of the nationalised undertakings is the responsibility of GdF. Taken together, these two articles authorise GdF as the sole importer and exporter of fuel gas into and out of France. The monopoly is not unfettered however. Agreements made by a licensed transport company to supply gas to an industrial customer, distribution company or for export have to be submitted to the administration responsible for gas matters. Such agreements may be opposed if it is in the public interest to do so, within two months of the date of receipt of the application. These provisions are also applicable to the import and export of LNG.

GdF has rights to transport gas under the NEG Act. In the case of the companies associated with the Lacq field in the South-west, the legal basis for these rights to transport is the NEG Act as amended by a law of 1949.

GdF is subject to the supervision of two Ministries, the Ministry responsible for gas and the Ministry responsible for economy and finances. In particular, the economic and financial control is exercised by the government in a permanent manner via a mission de controle placed under the authority of the Ministry of Economy and Finance. The Director General of Competition, Consumption and Investigation of Fraud has responsibility for implementation of a Declaration of 7 February, 1991 on prices of gas sold to distributors. Prior approval of the Ministries is required for specific acts, especially the `etats previsionnels' of receipts and expenses. External control therefore co-exists with a substantial element of internal control over the principal distributor. Governmental control over GdF is also exercised through a Council of Administration comprising six representatives of the State, six persons nominated by Decree, three because of their competence in this area, three to represent the consumers and the local communities and six to represent the employees. The President is chosen from among the Administrators and both he and the Director-General are named on the proposal of the Council of Administration following a decree of the Council of Ministers.

The body responsible for supervision of supply conditions and prices is the Ministry of Economy, Finance and the Budget. Penalties for non-compliance with supply conditions and prices cover the obligation to supply (obligation de résultat). The responsibility of GdF is fixed.

The industrial and commercial character of the GdF means that its operations fall under the rules of private law. At the same time GdF is subject to some controls applicable to public authorities. They concern the fixing of certain tariffs. GdF is obliged to honour the clauses in the schedule of charges which are laid down by the concession authority and in the standing charge contract itself and to follow the principles applicable to the idea of public service:

Under the Decree of 30 November, 1990, a distinction is made between `tarifs du reseau public de transport' (industrial consumers) and `tarifs du reseau de distribution' (distribution companies). With respect to industrial consumers, there is no obligation to supply; however, with respect to distribution consumers, there is an obligation to supply.

Prices for domestic consumers are subject to regulation by the Ministry of Economy, Finance and the Budget, according to Decree No. 90-1029 of 20 November 1990, irrespective of the stipulations of the schedule of charges and the contracts approved or concluded before entry into force of the Decree. According to Article 2 of the Decree, it is to take into account the costs of construction, maintenance and renewal of installations for storage, transport and distribution; the costs of providing the gas, and the costs of using the above installations.

The consumers are represented by "public representatives" in the Board of Directors of GdF. Links with consumer groups at the local level are encouraged by GdF, both to explain general policy and deal with complaints.

For non-domestic consumers, there is an obligation to supply the contracted quantities of gas except in the case of contracts for interruptible supplies of gas. This follows from the obligation to provide `egalite de traitement'. The average length of contracts is three years renewable by tacit agreement. In the cahier des charges, there is an obligation to provide continuity of service according to the conditions set out in the contract. Firm and interruptible contracts are used. With respect to the scale of tariffs, the approval of the administration is obtained automatically if there is no response within a period of seven days on receipt of a tariff.

In 1993, the Government commissioned a study on the Act of 1946 on the nationalisation of gas and electricity, as amended by an Act of 1949. Under these Acts only a public undertaking or a national company in which the state or public undertakings hold a majority, may transport natural gas to the inlet meter of a distribution company. The right to transport natural gas is currently limited to two undertakings: Gaz de France and SNGSO -Societe Nationale des Gaz du Sud-Ouest, in which Gaz de France has a 30% holding. The Ministries responsible for the regulation of the gas industry are the Ministry of Industry and the Ministry of Economy and Finance.

The study (the Mandil Report), where it applies to natural gas, argues that GdF should retain control over the provision of gas and this should be recognized by the priority award of import licenses. It supports the idea that large purchasers should be able to negotiate imports directly with international suppliers, and recommends that unbundling should be introduced to the extent of separating the GdF's accounts, but not its management.

2. Italy

Apart from some small domestic production, gas supplies are imported into Italy from several sources. Domestic gas is largely produced by AGIP, a wholly-owned subsidiary of the state-owned ENI. Transportation is carried out by SNAM, another subsidiary of ENI, which also purchases gas at the border of the exporting country. There is no legal monopoly of gas imports but the SNAM has the exclusive right to install and operate pipelines for the transport of hydrocarbons produced in Italy.

There is no single framework law governing the gas sector. The rules can be found in statutes and in the ENI Charter. The relevant laws are rules of Italian public administrative law, which differs considerably from the common law of England and the USA.

The pricing of gas by SNAM for gas distributors is not subject to strict regulation but is nevertheless subject to government intervention through the CIPE, an inter-ministerial committee (Comitato Interministeriale della Programmazione Economica).

There are two principal instruments for government control. Under the CIPE Decree of 26 June 1974, gas prices were to be frozen pending further decision. Through this measure, CIPE reserved the right to fix the price of gas for industrial, domestic and technological use, which is distributed by network for use in the domestic, crafts trades and industrial sector, and bottled gas. All decisions concerning the regulation of the price of methane gas subsequent to the decree were reserved to CIPE.

Under the CIPE Decree of 20 September 1974, price control was applied to natural gas prices. The price indexation system was originally based on the fuel oil price but now takes other factors into account. The control function is delegated to CIP (Comitato Interministeriale Prezzi).

In practice, the price of gas to distributors is agreed between SNAM and the association of gas distributors, then sent to CIP, which has the right to reject it. CIP has to be convinced that an increase in costs has occurred sufficient to justify the price increase. A complex method of calculation is used. The same principle is applied to the industrial customers. The agreed price is sent to CIP which may object to it. If it does not object, the procedure is straightforward: a single contract will be concluded, a carbon copy of the general agreement.

For domestic consumers CIP must specifically approve a price increase to consumers. Its decision is published in the official gazette. Law No 798 of 29 November 1984 for the protection of Venice provides a special reduction of the price for gas which is distributed to glass-manufacturing companies.

Some limited steps towards introducing wider access to existing networks have been introduced. In January 1991 Law No. 9 (Article 12) permitted producers of Italian gas to seek carriage (vettoriamento) from transporters if the gas is to be used in their own plants, or in plants owned by the parent company or affiliated company by the producers or to be delivered to the state electricity utility, ENEL or to companies falling within the scope of the existing legislation. Conditions and fees are to be agreed by the parties, taking into account remuneration of investments, the operating costs, the criteria followed in the European gas market in determining gas carriage fees for third parties and the evolution of the energy market. If the parties fail to reach agreement, the conditions and fee will be established by the Comitato Interministeriale Prezzi (CIP), after it has heard the parties. The gas to be carried has to be interchangeable and be acceptable in terms of transportability and content of noxious substances. Carriage proposals will be evaluated in terms of transportation capacity, development programmes and the utilisation ratio of the network.

All companies owning gas pipelines in Italy are subject to this carriage obligation. In practice, this means SNAM (the state gas company) and local distribution companies. However, the system was designed for use by SNAM. New market entrants will have to build new pipelines.

The issue of privatisation has raised much interest recently. This has concerned not only the privatisation of state-owned companies such as SNAM but of entities such as the ENI. A draft Decree envisaged a partial sale of shares in the public enterprises. This would have been made possible by the law but not mandatory and no deadline for privatisation was included. It would nonetheless be possible in theory to float all the shares. For SNAM, holding company would have been set up, with separate SNAM companies dealing with transportation and with purchase and sales.

3. Spain

Gas supply is a public service in Spain and is provided by the state or by the autonomous communities. There is a Gas Act of 1987 which sets out the main rules applicable to the sector. The legal device for the exploitation of the public service is the administrative contract or concession.

The allocation of authority between state and local government in the granting of concessions has been a subject of some controversy. There is a distinction in the Gas Act 1987 between concessions and authorisations. Once a company has been allowed to distribute gas by receiving a concession, it has to seek authorisations for the installations it requires, which are subject to a different procedure. Both concessions and authorisations are awarded by the Ministry of Industry or by the Energy Department of the Autonomous Community. Among gas companies this has been criticised as an excessively bureaucratic procedure. Every change they propose to make in their installations is subject to a prior authorisation from one or other body of government. The central government retains the main powers with regard to gas policy, because only the Ministry of Industry is allowed to award concessions and authorisations relating to fundamental aspects of the sector. This includes concessions for the use and exploitation of the National Gas Grid, strategical gas storages, regasification plants, concessions to distribution companies which operate in more than one Community and concessions for the international connection of the network.

The national gas utility is Empresa Nacional del Gas (Enagas). It is owned by the state through its holding company, the Instituto Nacional de Hidrocarburos (INH). Import, transmission and most sales of natural gas to industry are undertaken by Enagas. It also sells gas directly to power stations and to more than 320 large industrial consumers directly connected to the transmission network. Enagas is also responsible for the supply to more than thirty local distribution companies for resale to domestic and commercial users. Three of those companies also resell to industrial users: Gas de Euzkadi, Gas Madrid and Catalana de Gas (these two latter companies have been merged into Gas Natural, a new holding company). There is no significant private ownership in the Spanish gas industry.

INH has a significant role in the gas industry as the owner of Enagas. It is a government agency created in 1981 to hold investments in both the gas and the oil industries on behalf of the Kingdom of Spain. It was primarily designed to bring about a degree of vertical integration in the Spanish oil market. INH manages and monitors its investment in companies it controls through representation on the companies' boards of directors and through mandatory reporting, planning and authorisation requirements.

The exploration and production of oil and gas is carried out by Repsol, a subsidiary of INH, which was partly privatised in 1989: 26% of its shares were floated on the Madrid stock exchange or made available overseas. On privatisation, Repsol took over all INH's interests in exploration, production, refining, distribution and marketing of hydrocarbons and petrochemicals.

Repsol Butano is the major importer and distributor of butane and propane (LPG) in the Spanish market but is also involved in the natural gas market. While Spain lacks an extensive natural gas distribution system, LPG will remain an important fuel. The price at which Repsol Butano purchases gas from both domestic refiners and Enagas is controlled by the state. In the distribution sector, it is only involved in distributing natural gas to domestic and commercial consumers, since Enagas controls the sales to industrial users.

In the distribution sector a major change occurred during 1991-92. A new holding company called Gas Natural became the dominant player in the distribution of gas. It is the result of a merger of Gas Madrid (owned by Repsol) and Catalana de Gas. Gas Natural also combines the respective stakes of Repsol and Catalana de Gas in several distribution companies.

The Ministry of Industry is responsible for fixing the purchase and transfer prices of natural gas and LPG for the concessionaire companies. According to Article 15 of the Gas Act, the setting of prices is to take into account several factors such as the economic and financial situation of the company and the financing of R & D and compliance with the Government's objectives on gasification. Maximum selling prices are imposed on all tariff sectors but the aim is maximum price liberalisation in tariffs for the industrial users. All prices are valid for the whole country and are linked to the price of competitive fuels: essentially, heating oil and heavy fuel no.1. The aim is to fix prices to the final consumer in such a way as to allow a competitive position for gas as opposed to the other fuels to be substituted.

With respect to technical and safety standards, these are subject to regulations contained in the General Regulation of Public Service of Gaseous Fuels, approved by Decree 2913/1973 and regulations made under it.

In an effort to develop a gas market very quickly, Spain has opted for a highly `statist' approach to its organisation of the gas sector. This has not prevented a number of conflicts emerging between the central, regional and local authorities nor extensive criticisms from the gas companies about the extent of bureaucracy which this approach has entailed.

An announcement was recently been made that the state transportation company and monopoly supplier of gas to industrial customers, Enagas, would be taken over by the principal distribution company for domestic consumers, Gas Natural, which would create the third largest gas group in Europe after British Gas and Gaz de France. This step towards concentration in the Spanish gas industry, with no accompanying concern for the promotion of competition, is on the face of it rather inconsistent with the international trend.

Conclusions

In most of the European markets the gas industry is subject to a high degree of state control and in many cases of state ownership. Germany and Britain have privately owned industries but only in Germany is there evidence of regulation of the light variety. However, in that case the industry is characterised by a high degree of vertical integration by long-term contracts or corporate structure, particularly the former. Elsewhere, the aims of state interference are several, including security of supply, safety, the economy and environmental protection. As far as the domestic or small consumer end of the market is concerned, political reasons play a role.

In Britain efforts have been made to regulate the industry to promote competition. This has been done through the regulatory agency, the Office of Gas Supply and also through the competition law. Since privatisation, both have been active in promoting competition, with some success. A key role in the process has been played by the licence as vehicle for public control over the monopolist's operations, permitting a number of modifications to be made with the consent of both parties. However, since privatisation a key role has been played by competition law as well as an active regulator in eroding the power of the monopolist in Britain. In the regimes described herein as state models, such as France, Italy and Spain, the role of competition law has been negligible and the role of state agencies much greater. However, the regulatory mechanisms of these countries should not be underestimated. In most cases, the vehicle for exercising control is the concession granted for transport or distribution or both. Ministries have been granted fairly extensive powers to intervene or alternatively the institutional frameworks are designed in such a way as to permit frequent participation by the government in decision-making.

The scope for private parties to challenge anti-competitive behaviour in the state models is minimal or non-existent - in contrast to the United States. In those countries with extensive regulatory systems, one may note that, irrespective of having unitary or federal systems, the regulatory power is fragmented, involving several agencies (Britain, the US and Germany).

In North America and Europe virtually all countries have been reviewing their legal frameworks for gas production, transportation and distribution. Their reasons for doing so and their aims differ widely but the trend is clear: to reduce the scope of monopoly and to induce gas companies to behave as if they were stimulated by a more competitive environment. The instruments adopted include the removal of legal monopolies and exclusive rights, privatization, open access to pipeline networks, unbundling of services and the use of regulatory bodies to enforce these market-oriented policies. This body of international experience may yield lessons. However, three considerations need to be taken into account. Firstly, there is no single model which might be applied to Brazil's gas sector, only lessons and cautionary advice in designing a Brazilian system. Secondly, much innovation has occurred in markets which have already attracted major investments in their gas markets, whereas Brazil has the challenge of designing a system from scratch which is both market-oriented and which attracts large investments. Finally, it is likely that the experiences of countries which have large state sectors will probably be most relevant.

ANNEX 4.4

SCENARIOS FOR CONSTITUTIONAL REFORM

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Option 1 Retention of Petrobras Monopoly

	Imports	Production	Transmission	Distribution
Petrobras	X	X	X	
States:				
- Comgas				X
- CEG				X
Other States				xx...

ADVANTAGES:

* Integrated Control of Gas Flows From Production to Transmission
* Very limited number of agents to deal with.
* Large Entity Able to Deal Strongly on Imports
* Integrated control makes distribution of rents easy.

DISADVANTAGES:

* Gas sector development constrained by the financial possibilities of a single entity.
* Strong and extensive regulation required, requiring high calibre independent expertise which may not be available in the country, with access to information likely to be difficult.
* Least attractive to private investors, due to concentrated power of a single (state owned) monopolist, most stages of the oil and gas buinesses and to extensive price controls.
* Petrobras may be tempted to influence gas-to-oil competition to suit its best interests.
* Lack of transparancy in costs and benefits at all stages, and liklihood of cross-subsidies.
* Price controls threaten viability of distribution Activities.
* Least attractive to consumers; No competition, hence i) no real customer choice ii) no competitive pressure to improve efficiency iii) no market determination of price
  Largest potential for abuse of monopoly power.
* Domestic gas resources not fully exploited.
* Petrobras get political concessions on prices and subsidies.
* System encourages Petrobras to empire build.
* No open access.

REGULATION REQUIRED:

* Core regulations, except for concessions (not required).
* No open access allowed.
* Setting up of gas prices, transmission and distribution tariffs at every level; setting up of oil product prices at refinery levels to reflect economic costs, setting up of power tariffs to reflect LRMC.

Option 1(continued)

* Control of gas allocation to categories of clients and types of uses, in particular self-use by Petrobras.
* Possibly prohibition of Petrobras entering the distribution stage.
* Profit Accounting for Different Activities Required (imports,production etc)
* Unbundling within Major Activities Required

Option 2a Relinquish Petrobras Monopoly for Gas Imports and Transmission and State Monopolies over Distribution

	Imports	Production	Transmission	Distribution
Petrobras	X	X	X	
Others	XX...		XX...	
Comgas				X
CEG				X
Other States				XX...
Private Concessions				XX...

ADVANTAGES:

* Will help bring private sector resources in capital intensive transmission segment, and into faster development of the distribution networks.
* Increased competition at transmission and distribution levels, making comparison of performance feasible.
* Though limited to two transmission supply networks, introduces gas-to-gas competition in the main Sao Paulo market, thus providing some user choice, more incentives for efficiency and for lower prices.
* Limits the possibilities for manipulation of oil-to-gas competition.
* More transparancy in costs and prices, thus limits the possibilities of cross subsidies.
* More incentives for downstream investments if users have more than one choice (improved security of supplies).
* Provides more incentives for Petrobras to efficiently develope domestic gas resources.
* Regulation is easier, because more transparant information is accessible from several sources, and comparisons of performance are possible; increased market determination of prices at import, production and transmission stages.
* Increased efficiency from the process of granting concessions (transmission, imports, distribution) through a bidding process.

DISADVANTAGES:

* Domestic production is still constrained by Petrobras's ability to develop these resources and its own balance of interest between oil and gas.
* Scope for manipulation of oil-to gas competition still exists,though more limited.
* Need to provide open-access (at least to importers), and by-passes after a market development phase, introduce an element of uncertainty which may discourage investors at this stage of development.
* Uncertainty in the distribution of rents may discourage investors at this stage of development.

Option 2a (Continued)

REGULATION REQUIRED:

* Core regulation, including concessions.
* Open Access on transmission system.
* Setting up gas transmission tariffs (through price cap) and gas prices to captive consumers, with gas prices elsewhere freely negotiated.
* Setting oil prices ex-refinery to reflect economic costs, and electricity tariffs on the basis of LRMC.
* Watching over oligopolistic tendencies, especially at the transmission stage.
* Watch for unfair practices associated with cross ownership of upstream and downstream activities, whilst allowing a degree of cross ownership with the exception of the transmission function.

Option 2b Relinquish Petrobras Monopoly for Gas Imports & Production and State Monopolies over Distribution

	Imports	Production	Transmission	Distribution
Petrobras	X	X	X	
Other Suppliers	XX...	XX...		
Comgas				X
CEG				X
Other States				XX...
Private Concessions				XX...

ADVANTAGES

* Faster development of domestic gas resources, hence increased availability of gas on the market;
* Will attract private sector investment in exploration and production stages;
* If concessions granted through bidding, domestic gas development should be at the lowest cost;
* Greater specialization at production and import stages will permit comparison of performance increase efficiency and lower costs;
* Access of imported gas will have the same effect - more sources of gas should lead to lower domestic prices;
* Still a large measure of integrated control of gas flows from production through transmission;
* Gas consumers and distributors have more choice to contract their own supplies, which will encourage private sector investment in power generation and distribution;
* Greater possibilities for consumers to negotiate for supplies giving rise to gas completion and more pressure on PETROBRAS to increase efficiency of its own domestic production;
* Stronger indirect inputs from producers and clients into planning of transmission networks.

DISADVANTAGES

* Transmission network still controlled by the major gas and oil producer, allowing the risk of abuse of power to influence gas to gas and oil to gas competition (e.g., by denying access or Charging others excessive transmission fees);
* Probability of cross-subsidies within PETROBRAS system.

Option 2b (Continued)

REGULATION REQUIRED

* Strong regulator required, focusing of control of abuse of monopoly power at the transmission stage and watching over oil-to-gas completion;
* Gas prices freely negotiated, but regulator sets transmission fees on price cap basis. Oil product and power prices set as for previous options.

Option 2c Relinquish Monopoly for Gas Imports, Production, Transmission and Distribution, and State Monopolies over Distribution

	Imports	Production		Distribution
Petrobras	X	X	X	
Other Suppliers	XX...	XX...	XX...	
Comgas				X
CEG				X
Other States				XX...
Private Concessions				XX...

ADVANTAGES

* Promotion of competition at all stages, will further efficiency, low prices;
* Comparison of performance possible at all stages, making regulation easier;
* Lighter regulation required, limited to natural monopoly stages (transmission and distribution to residential sector);
* Attractive to private sector, will promote faster development at all stages;
* Best for consumers as they have the most choices;
* Planning of networks the most market-responsive, hence, the most efficient;
* Award of concession through bidding process also helps achieving efficiency and lower prices;
* No price setting required except transmission and residential distribution tariffs.

DISADVANTAGES

* Elements of natural monopoly in transmission and distribution still require regulation;
* Still scope for manipulation of oil-to-gas competition by Petrobras which may discourage investors;
* Requires regulator to watch over a larger number of agents and concessions;
* Distribution of rents left to negotiations may be discouraging for large investments in transmission.

REGULATION REQUIRED

* Regulation of tariffs for gas transmission and captive consumers;
* Regulation of oil product prices and power tariffs as in previous options;
* Open access.
* Watch for unfair practices associated with cross ownership of upstream and downstream activities, whilst allowing a degree of cross ownership.

Option 3 No Monopolies on Either Gas or Oil

	Imports	Production	Transmission	Distribution
Petrobras	X	X	X	
Other Suppliers	XX...	XX...	XX...	
Comgas				X
CEG				X
Other States				XX...
Private Concessions				XX...

ADVANTAGES

- Same as previous option, plus;
- Oil to gas competition only subject to market forces.

DISADVANTAGES

* Same as previous option, except for risks of manipulation of oil to gas competition.

REGULATION REQUIRED

* Same as previous option, except that oil product prices no longer need to be set, but are left to market forces;
* No need for regulator to watch over oil-to-gas competition.

Regulatory Requirements Common to All Options

A. REGULATIONS (Gas Act, plus complementary regulations)

- Approve prices and fees at the natural monopoly stages: Transmission fee (Price Cap); gas price to residential consumers;
- Obligation to supply;
- Prevention of abuse and control of monopoly power (to avoid discrimination and denial of access to gas);
- Regulations regarding distribution by-pass
- Obligation to supply information;
- Quality of gas;
- Quality of service;
- Avenues for consumer complaints and resolution of disputes;
- favorable foreign investment regulations.

B. REGULATORS

At FEDERAL Level :

- Independent regulator with emphasis on production, transmission and import stages, and for establishing principles and norms (safety, gas quality) applicable to distribution stages; watching over compliance with terms of concession contracts at E and P and transmission levels;
- Government authority to grant E and P, transmission and imports concessions (when possible), based on criteria established by law; and
- Consumer/users representation bodies/councils.

At STATE Level:

- Independent state regulators with emphasis on distribution stages; and on watching over compliance with terms of distribution concessions;
- State government authority to grant distribution concessions;
- Consumer representation councils/bodies.

ANNEX 4.5

FRAMEWORK OF A GAS LAW

FRAMEWORK OF A GAS LAW

Summary of Main Provisions

1. Scope and Aims of the Legislation and Definitions
[To include references to the highest international standards; security of supply; low prices to be sought; definitions of key terms such as concession, production, transportation, and distribution]

2. Rights of the Federal and State Authorities over Gas
[Nature of provision will vary according to constitutional arrangements; aim is to assert Federal Authority's exclusive right to act with respect to the provision of gas supply. Fundamental building block for the entire legal structure and its right to act in this area; then a division of competence between federal and state authorities]

3. Planning and Development of the Gas Network
[The scale and the integrated nature of gas operations requires a clear scheme for co-ordination of the gas supply, identifying the appropriate Federal Ministry and State authorities as the key bodies with responsibility for fostering development of the gas network]

4. Prohibition of Unauthorised Supply
[Gas is a substance of strategic importance which needs careful handling for reasons of safety. It should be supplied only by persons who are permitted to do so by authorisation, not least to ensure uniform standards. The regulatory authority will have a role in advising on safety aspects of such authorisation]

5. Concession System
[A system needs to be developed for licensing utilities to finance, design, build, develop, operate, repair, maintain and own an efficient, co-ordinated and profitable high-pressure or low -pressure system; procedures for award of such concessions; various service obligations have to be included since the element of public interest is considerable; the competences of federal and state authorities have to be clearly specified]

6. Gas Storage
[To fix authority for gas storage on the appropriate Federal and State authorities and to ensure that the authorities have the means to exert control by means of a licence over any entity or entities granted rights to store gas]

7. Regulation of the Gas Supply
[To establish a regulatory agency distinct from the Minister and its composition, powers and duties; detail of provisions dependent upon policy decisions taken with respect to industry structure and type of agency preferred: e.g. specialist or sectoral in scope; need to link the operations of the regulator to any existing competition authority to avoid overlap and strengthen the pro-competition aspects of the structure]

8. Public Gas Supply Regulation
[To comprise the regulation of various technical and safety matters which, due to their need to be amended and up-dated from time to time, often with the agreement of the parties, should not be included in the basic law but in a form of subordinate legislation]

9. Tariffs
[To establish the tariff principles in the regulatory framework, not to create rigidity. Distinct procedures to be set out for approvals of gas tariffs in the large industry sector and in the small consumer market. Regulatory uncertainty to be avoided with respect to the calculation of rate of return to investors]

10. Standards of Quality
[To establish the essentials with respect to quality standards without entering into the sort of matters which can be covered in subordinate legislation. It identifies responsibility and ensures that the information flows are satisfactory to permit monitoring of gas quality]

11. Investigation of Complaints
[To provide for a procedure for the fair and prompt handling of complaints from all classes of customer. Must be effective]

12. Access to Land
[To provide for speedy access to land for the purpose of laying and maintaining pipelines. Balance required between protection of private property rights, environmental interests and investors' concern about large costs of delays to projects, which can be a serious disincentive]

13. Enforcement
[To designate the appropriate federal and state authorities for enforcement of the law and of the terms of the concessions granted]

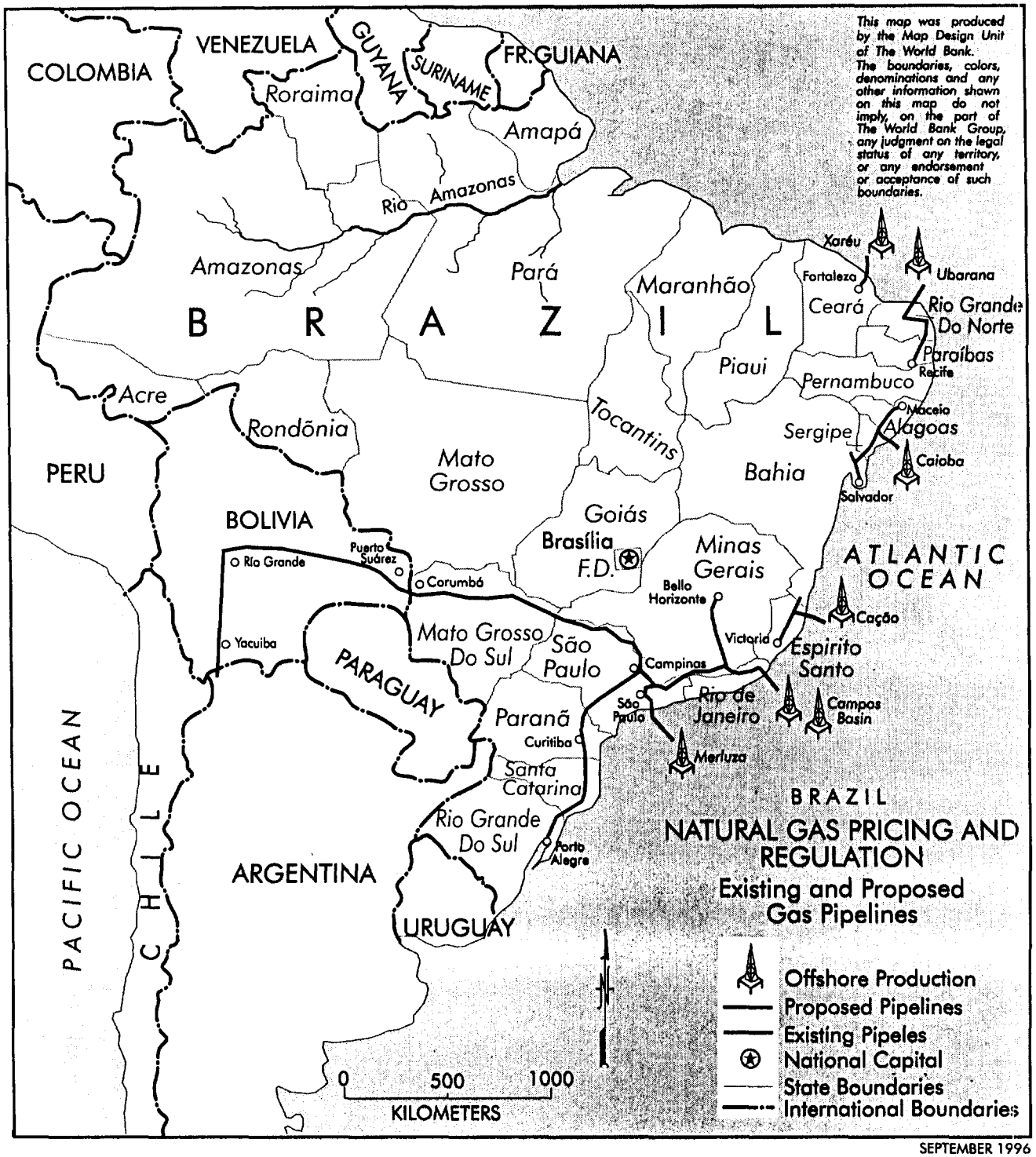
14. Gas Consumers Councils
[To require the Federal and State authorities to establish channels for advice on consumer matters with powers to refer complaints and make recommendations to the regulatory agency]

15. Transitional Provisions, affecting existing rights
[To set out details of a transitional period from adoption of this Law to full implementation. To provide potential investors with as much security as is necessary to go ahead with their plans]

16. Affected Legislation
[Prior legislation containing conflicting provisions to be superceded by provisions in this Law]

17. Entry into Premises

IBRD 28067



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